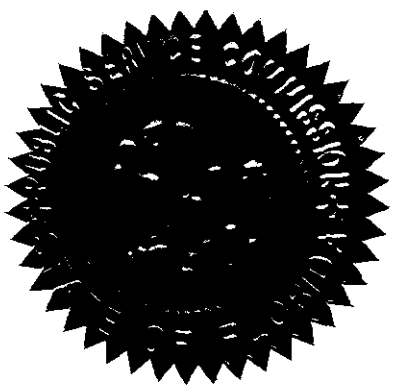
BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 080253-EM

In the Matter of:

PETITION TO DETERMINE NEED FOR CANE ISLAND POWER PARK UNIT 4 ELECTRICAL POWER PLANT IN OSCEOLA COUNTY, BY FLORIDA MUNICIPAL POWER AGENCY.

_____/



PROCEEDINGS:	HEARING
BEFORE:	CHAIRMAN MATTHEW M. CARTER, II COMMISSIONER LISA POLAK EDGAR COMMISSIONER NANCY ARGENZIANO
DATE:	Monday, August 4, 2008
TIME:	Commenced at 9:30 a.m. Concluded at 9:38 a.m.
PLACE:	Betty Easley Conference Center Room 148 4075 Esplanade Way Tallahassee, Florida
REPORTED BY:	JANE FAUROT, RPR Official FPSC Reporter (850) 413-6732

DOCUMENT NUMBER-DATE
06893 AUG-5 08
FPSC-COMMISSION CLERK

(REPORTER NOTE: Page 2 inadvertently blank.)

APPEARANCES:

FREDERICK M. BRYANT, ESQUIRE, Post Office Box 3209, Tallahassee, Florida 32315-3209, representing Florida Municipal Power Agency.

GARY V. PERKO, ESQUIRE, Hopping Law Firm, Post Office Box 6526, Tallahassee, Florida 32314, representing Florida Municipal Power Agency.

KATHERINE FLEMING, ESQUIRE and ERIC SAYLER, ESQUIRE, FPSC General Counsel's Office, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing on behalf of the Florida Public Service Commission Staff.

I N D E X

WITNESSES

NAME:	PAGE NO.
ROGER A. FONTES	11
THOMAS E. REEDY	19
JONATHAN P. NUNES	41
MYRON R. ROLLINS	48
JASON L. WOLFE	64
NICHOLAS P. GUARRIELLO	70
BRADLEY E. KUSHNER	90

EXHIBITS

NUMBER:		ID.	ADMTD.
1	Comprehensive Exhibit List	7	8
2	Staff's Composite Exhibits	7	8
3-17	(Description contained in Comprehensive Exhibit List	7	10
18	Proof of Publication	10	10

P R O C E E D I N G S

CHAIRMAN CARTER: I would like to call this hearing to order. First of all, Commissioner Argenziano, are you there?

COMMISSIONER ARGENZIANO: Yes, sir, I sure am.

CHAIRMAN CARTER: Good morning. Good morning to you.

COMMISSIONER ARGENZIANO: Good morning.

CHAIRMAN CARTER: I hope you had a great weekend. I certainly did.

COMMISSIONER ARGENZIANO: I'm glad to hear that.

CHAIRMAN CARTER: Commissioner Edgar and I were here commensurating about how much we had to spent on our kids this weekend. Other than that, it's a pretty nice day. All right, then.

So, staff, read the notice, please.

MS. FLEMING: Pursuant to notice issued by the Commission Clerk, this time and place has been set for a hearing in Docket Number 080253-EM.

CHAIRMAN CARTER: Okay. Let's take appearances.

MR. PERKO: Good morning, Mr. Chairman.

Gary Perko with the Hopping Green and Sams law firm on behalf of the Florida Municipal Power Agency, and with me is Mr. Frederick Bryant, General Counsel for FMPA.

MS. FLEMING: Katherine Fleming and Erik Sayler on behalf of the Commission.

CHAIRMAN CARTER: Thank you.

Staff, are there any preliminary matters?

MS. FLEMING: Yes, Chairman, there are several preliminary matters, such as the proposed stipulation of issues, and the witnesses that have been excused. I would suggest that we just take that up at the beginning of the technical portion of the hearing.

CHAIRMAN CARTER: Okay.

MS. FLEMING: And at this time, staff has prepared a Comprehensive Exhibit List, and we would request that the exhibits be identified and marked as indicated in the Comprehensive Exhibit List.

CHAIRMAN CARTER: Okay. Without objection, show it done.

(Exhibits 1 through 7 marked for identification.)

CHAIRMAN CARTER: Any other preliminary matters?

MS. FLEMING: I'm not aware of any other matters, Chairman.

CHAIRMAN CARTER: Okay. Let's go into our public testimony portion. Do we have anyone wishing to speak, anyone from the public?

MS. FLEMING: I'm not aware of anyone here wishing to speak on this matter.

CHAIRMAN CARTER: Is there anyone in the audience? Okay.

Hearing none, let's proceed. We will close out our public testimony and convene our technical hearing.

And with that, Mr. Perko and Mr. Bryant, whichever if you wish to make an opening statement, you are recognized.

MR. PERKO: Just very briefly, Mr. Chairman.

The Florida Municipal Power Agency in a joint power agency consisting of member municipalities throughout the state of Florida located from Key West to Havana. And we are very pleased that the staff has concluded that our project meets the growing needs of FMPA's All Requirements Power Supply Project, which is an important component of meeting the needs of its 15 member municipalities. And we thank staff for its hard work and cooperation in this matter.

CHAIRMAN CARTER: Thank you so kindly.

Staff, are there any preliminary matters?

MS. FLEMING: Yes, Chairman.

As we discussed previously, at this time we have marked and identified Exhibit 1, which is the Comprehensive Exhibit List, and, Exhibit 2, which is Staff's Stipulated Exhibits. Staff would request that Exhibits 1 and 2 be moved into the record.

CHAIRMAN CARTER: Commissioners, any objections? Show it done.

(Exhibits 1 and 2 marked admitted into the record.)

CHAIRMAN CARTER: Staff, you're recognized.

MS. FLEMING: Staff would also like to note that all witnesses have been excused, and at this time I would suggest that FMPA address their prefiled testimony and their exhibits.

CHAIRMAN CARTER: Mr. Perko.

MR. PERKO: Would you prefer that I take them separately, Commissioner?

CHAIRMAN CARTER: You can just do one omnibus presentation, that would take care of it.

MR. PERKO: Okay. At this time, FMPA would request that the testimony of all of its witnesses be entered into the record as if read.

CHAIRMAN CARTER: Any objections? Without objection, show it done.

MR. PERKO: And at this time, Mr. Chairman, FMPA would request that all the exhibits listed on staff's composite exhibit list be entered into the record.

CHAIRMAN CARTER: Let's do this first. Let's move the notice. Let's do the notice.

MR. PERKO: Okay.

MS. FLEMING: The notice would be Hearing Exhibit 18.

CHAIRMAN CARTER: Commissioners, this is the notice that's showing proof of publication of the notice for FMPA on this matter, and we will just make that Exhibit Number 18, is that correct?

MS. FLEMING: That's is correct.

CHAIRMAN CARTER: Any objections? Without objection, show it done.

(Exhibit Number 18 marked for identification and admitted into the record.)

CHAIRMAN CARTER: Now, Mr. Perko, you're recognized for the remainder of your exhibits.

MR. PERKO: Thank you.

At this time, FMPA would request that all the exhibits listed on Staff's Comprehensive Exhibit list be entered into the record.

CHAIRMAN CARTER: Any objections? Without objection, show it done.

(Exhibit Number 3 through 17 admitted into the record.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

ROGER A. FONTES

ON BEHALF OF

FLORIDA MUNICIPAL POWER AGENCY

DOCKET NO. _____

MAY 7, 2008

Q. Pease state your name and business address.

A. My name is Roger A. Fontes. My business address is 8553 Commodity Circle, Orlando, Florida 32819.

Q. What is your current position?

A. I am General Manager and Chief Executive Officer of Florida Municipal Power Agency, which is commonly referred to as FMPA.

Q. Please briefly describe your professional background.

A. I have over 37 years of experience in the utility industry. Prior to joining FMPA in 2001, I was the Assistant General Manager at the Northern California Power Agency (NCPA). I spent 20 years with NCPA, including executive positions as System Planning and Development Manager and Legislative and Regulatory Manager. During this period I was appointed by California's Governor and the U.S. Secretary of the Interior to serve on the Bay-Delta Advisory Council representing the state's hydroelectric power industry. Prior to joining NCPA, I was

employed for five years by the California Energy Commission as Chief Energy Engineer and Energy Supply Assessment Manager. Prior to that, I was with the City of Los Angeles Department of Water and Power from 1971 to 1976.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an overview of FMPA and its All-Requirements Power Supply Project (ARP) relative to the need for Cane Island 4. I also will discuss FMPA's ability to finance the construction of Cane Island 4.

Q. Are you sponsoring any Sections of the Need For Power Application that has been marked as Exhibit No. ___ [FMPA-1]?

A. Yes. I am sponsoring Section 22.0 of the Application, which was prepared under my direct supervision.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring Exhibit No. __ [RAF-1], entitled "ARP Member Cities."

Q. Please describe FMPA.

A. FMPA is a nonprofit, public, joint action agency consisting of 30 municipal electric utilities with the primary purpose of developing competitive power supply and related services. FMPA's mission is to develop economical and competitive power supply projects, to be proactive in providing member services, and to promote the image of public power, enabling its member utilities to succeed in a rapidly changing environment. Each member appoints one representative to FMPA's

Board of Directors, which governs the Agency's activities. Each member utility is locally owned and operated; however, municipal utilities share common concerns that can best be solved by working together. This helps reduce the cost of power through economies of scale. Through FMPA, municipals have been successful in reducing power costs, diversifying power supply resources, and providing a measure of competition in the wholesale market.

Q. Please provide an overview of the All-Requirements Power Supply Project.

A. FMPA is specifically authorized under the Joint Power Act to undertake joint projects for its members and to issue tax-exempt bonds and other obligations to finance the costs of such projects. Pursuant to that authority, FMPA developed the ARP to secure an adequate, economical and reliable supply of electric capacity and energy to meet the needs of the ARP members, which are comprised of fifteen municipal utilities serving approximately 180,000 customers throughout Florida. ARP members purchase all their capacity and energy from the ARP. FMPA serves the needs of the ARP using FMPA owned or co-owned facilities, as well as power purchases from generating ARP members (i.e., members with their own generating capacity and purchases) and other, utilities or independent power products (IPPS).

Q. Who are the fifteen members of the ARP?

A. The fifteen ARP member utilities currently include the Kissimmee Utility Authority, Fort Pierce Utilities Authority, Keys Energy Services (Key West), Beaches Energy Services (Jacksonville Beach), and the Cities of Bushnell, Clewiston, Fort Mead, Green Cove Springs, Havana, Lake Worth, Leesburg,

Newberry, Ocala, Starke and Vero Beach. With members extending from Havana to Key West, the ARP member cities are geographically diverse, as shown in Exhibit No. __ [RAF-1].

Q. Please describe how the Membership governs the ARP.

A. The ARP is governed by an Executive Committee. The Executive Committee is comprised of one representative from each of the 15 ARP members.

Q. What steps has FMPA taken to lower cost and improve reliability for the ARP?

A. Historically FMPA's options were limited to being a joint participant in generating units to obtain fuel diversity and economies of scale. Examples of these projects include the St. Lucie 2 nuclear unit, the Stanton 1 and 2 coal fueled units, and the Stanton A and Cane Island 2 and 3 combined cycle units. In addition, FMPA relied on purchase power agreements. Many of the ARP member owned generating units are old and inefficient. Recently FMPA has been developing new larger and more efficient combined cycle units in order to meet ARP load growth and to allow retirement of the old inefficient member generation. One example of this is the Treasure Coast Energy Center in Fort Pierce which is scheduled to enter commercial operation in May 2008. Another example is this proposed Cane Island Unit 4. These efficient combined cycle units have allowed FMPA to reduce generating costs with natural gas by significantly lowering the system heat rate. This retooling and modernization of the ARP system has the additional benefit of reducing emissions, including emissions of CO_2. Without these new combined

cycle units including Cane Island 4, it would be very difficult for FMPA to reduce emissions cost effectively.

FMPA has also been active in the areas of renewables and DSM. FMPA went to the market through several requests for proposals (RFP) which will be discussed in detail by our other witnesses. We continue to negotiate in earnest with a number of the bidders. Since our member cities are surrounded by the investor-owned utilities service areas, it is extremely important that our rates remain competitive. Thus the cost of renewables and their overall impact on our rates is important. One of the bright spots from our RFP process is the identification of a 10 MW initial solar photovoltaic project with potential to ultimately increase the photovoltaic capacity to 100 MW. Our Executive Committee is currently scheduled to address approval of the contract for the initial 10 MW at their May 22, 2008 meeting. While the costs are significantly above our avoided costs, many of our members feel it is important to move forward with solar. I am optimistic about the projects' ultimate implementation. FMPA's potential 10 MW solar project is significant, particularly considering the size of FMPA's system. By comparison, Florida Power & Light Company (FPL), which has a much larger system, recently announced an equally sized (10 MW) initial commitment to solar with a potential ultimate commitment of 300 MW.

With respect to DSM, FMPA is negotiating with bidders from the RFP process and I am hopeful that an agreement will be reached that will enable FMPA to cost effectively reduce our peak demand.

In the longer term, FMPA is actively pursuing nuclear capacity for economic and environmental benefits. FMPA has been in active discussions regarding participation in Progress Energy Florida's Levy County Units 1 and 2. FMPA is also looking forward to discussions with FPL for potential participation in Turkey Point Units 6 and 7.

Q. How does FMPA intend to finance the construction of Cane Island 4?

A. FMPA has several funding sources available that may be used to finance the development and construction of Cane Island 4. These sources include internal funds, pooled loans, and new long-term debt issuances.

Q. Please explain how these financing sources may be used by FMPA.

A. FMPA would typically use a combination of pooled loans and long term debt.

As the initial development concludes and construction commences, FMPA may rely on its pooled loan commercial paper to get the construction process underway. The pooled loan is an ongoing FMPA project which provides FMPA and its members' loans at very competitive rates which are ultimately financed with tax exempt commercial paper. The pooled loans could be expected to be used for financing up to the first $100 million of costs.

Once the project is well defined and construction underway, FMPA could and would ultimately initiate a revenue bond issuance for long-term project funding.

Q. Is FMPA confident in its ability to secure revenue bonds to finance Cane Island 4?

A. Yes. Based on the project's favorable economics and FMPA's excellent credit rating, we believe there will be no problems issuing debt to cover the project cost. FMPA has recently initiated bond offerings with tax-exempt interest rates consistent with or below the rates assumed for the economic analyses of Cane Island 4.

Q. What are FMPA's current credit ratings?

A. FMPA has a credit rating of A+ from Fitch and an A1 from Moody's Investors Service. Typically, FMPA purchases bond insurance on its long-term bonds to increase its ratings to AAA and Aaa, respectively.

Q Please summarize FMPA's need for Cane Island 4.

A. As discussed in detail in the Need for Power Application and testimony of other witnesses, Cane Island 4 is needed by FMPA to maintain the ARP's system reliability by providing capacity to meet load growth and to enable potential retirement of old inefficient units. Cane Island 4 is FMPA's lowest cost alternative and provides significant environmental benefits to FMPA's system. While renewables, DSM, and conservation are and are projected to be important parts of the ARP system, there are no reasonably available renewable, DSM, or conservation alternatives which would supplant the need for Cane Island 4.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF THOMAS E. REEDY

ON BEHALF OF

FLORIDA MUNICIPAL POWER AGENCY

DOCKET NO. _____

MAY 7, 2008

Q. Please state your name and business address.

A. My name is Thomas E. Reedy. My business address is 8553 Commodity Circle, Orlando, Florida 32819.

Q. By whom are you employed and in what capacity?

A. I am employed by Florida Municipal Power Agency (FMPA) as the Assistant General Manager of the Power Resources Division.

Q. Please describe your responsibilities in that position.

A. As the Assistant General Manager of the Power Resources Division for FMPA, I have responsibility for managing power supply and transmission planning, project development, power supply contracts, regulatory affairs, operations, and fuels.

Q. Please state your educational background and professional experience.

A. I received a Bachelor of Science degree in Electrical Engineering, with a focus on Electrical Energy Engineering, from the University of Florida, Gainesville,

Florida. I am a registered professional engineer in the state of Florida. My 30 years in the electric utility industry have encompassed many facets of the business, including experience in cogeneration development, electric utility planning, electric utility dispatching and operations, forecasting and load research. Before joining FMPA, I served four years as an executive consultant for Resource Management International, Inc (now Navigant Consulting).

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to:

- explain how FMPA serves the needs of the All-Requirements Power Supply Project (ARP);
- discuss FMPA's participation the Florida Municipal Power Pool (FMPP)
- summarize FMPA's existing generation system and existing purchase power resources as well as FMPA's transmission system;
- provide an overview of the supply of natural gas and availability of natural gas transportation for Cane Island 4;
- discuss transmission system impacts associated with the addition of Cane Island 4.
- summarize FMPA's historical and planned conservation and DSM programs; and
- discuss the solar photovoltaic (PV) resources that FMPA is considering as a result of a request for proposals process.

Q. Are you sponsoring any exhibits as part of your testimony?

A. Yes. I am sponsoring Exhibit No.__ [TER-1], entitled "ARP's Existing Resource Capacity," and Exhibit No.__ [TER-2], which is a copy of my resume.

Q. Are you sponsoring any sections of Exhibit No. __ [FMPA-1], the Cane Island Unit 4 Need for Power Application?

A. Yes. I am sponsoring Sections 3.0, 6.0, 8.0, 11.0, 16.3, 17.0 (except for 17.2), and Appendix C, all of which were prepared under my direct supervision.

Q. Why is FMPA submitting a Need for Power Application?

A. FMPA is projected to require additional capacity by 2011 to continue to reliably serve the needs of ARP members.

Q. How does FMPA serve the ARP members' electricity needs.?

A. ARP members are required to purchase all of their capacity and energy from the ARP with the exception of excluded resources that are the ARP members' ownership shares of nuclear generating units (Crystal River 3 and St. Lucie 2). ARP members that own generation must make that capacity available for use by the ARP. The ARP supplies all the member requirements with FMPA owned resources, jointly owned resources, purchased power, and member owned resources. ARP member contracts for purchase and sale have an initial term of 30 years and are then automatically extended on a year-for-year basis.

Q. Please describe the Florida Municipal Power Pool.

A. The FMPP was formed in 1988 and is a power pool comprised of three members including the Orlando Utilities Commission (OUC), Lakeland Electric, and FMPA. The FMPP's member generating resources are centrally dispatched to meet the combined energy requirements of the FMPP members.

FMPP resources include the members' generating units as well as purchased power. Each FMPP member is responsible for maintaining sufficient capacity to serve its own load, including an adequate reserve margin. The resources are committed and dispatched by OUC, which handles the day-to-day operations of the FMPP.

Q. Please describe FMPA's current spinning and operating reserve requirements.

A. The Florida Reliability Coordinating Council (FRCC) operating reserve is maintained by the combined systems in Florida at a value equal to, or greater than, the summer gross FRCC capability rating of the largest generating unit in service in FRCC. Currently, the operating reserve requirement of the FMPP is 99 MW, which includes 25 MW of spinning reserves. FMPA's share of FMPP's operating reserves is 31.6 MW, which includes 7.9 MW of spinning reserves.

Q. Please describe FMPA's current transmission system.

A. Florida's electric grid is tied to the rest of the continental United States at the Florida/Georgia/Alabama interface. Florida Power & Light Company (FPL), Progress Energy Florida (PEF), JEA, and the City of Tallahassee own the transmission tie lines at the Florida/Georgia interface. ARP members' transmission lines are interconnected with transmission facilities owned by FPL, PEF, OUC, JEA, Seminole Electric Cooperative, Florida Keys Electric Cooperative Association, and Tampa Electric Company (TECO). The Florida electric transmission grid is interconnected by high voltage transmission lines ranging from 69 kV to 500 kV.

Q. Does the ARP utilize purchase power contracts as part of their power supply portfolio?

A. Yes. The ARP may purchase power from other entities to contribute to its power supply resources. Additionally, purchase power contracts that individual member cities had in place prior to joining the ARP are utilized to serve the ARP's electricity needs. Existing purchase power contracts include purchases from PEF, FPL, Calpine, and Southern Power Company.

Q. Did FMPA consider either extending existing purchase power contracts or entering into new purchase power contracts in lieu of the construction of Cane Island 4?

A. Yes. FMPA held discussions with PEF, FPL, and Calpine regarding extension of existing purchase power contracts that will expire in the near future. These

discussions did not result in any contract extensions. The Southern Power Company contract already contains contract extension provisions and for evaluation purposes, it was assumed to extend through the evaluation period.

As discussed in the prefiled testimony of Mr. Nicholas Guarriello, FMPA conducted a request for proposals (RFP) process to solicit power supply offers from other entities. No responses to the power supply RFP were submitted to FMPA.

Q. Please summarize the capacity resources currently available to the ARP.

A. The ARP's existing capacity resources (summer rating) are presented in Exhibit No. __ [TER-1]. Exhibit No. __ [TER-1] illustrates that ARP's capacity resources decrease as many of ARP's purchase power contracts will expire in the near-term and older, less efficient generating units are retired.

Q. Which units will be retired and how will their retirement affect FMPA's generating capacity?

A. FMPA plans for certain member-owned generating units to be retired because of their age and inefficiency. However, ARP members control the retirement of their generating units. The units planned by FMPA to be retired during the period considered in this Application include units owned by Fort Pierce Utilities Authority, Lake Worth, and Kissimmee Utility Authority. The total reduction in summer capacity due to these unit retirements is 250 MW.

Q. Are there concerns regarding the availability of natural gas?

A. No. Based on information provided in the Energy Information Administration's Annual Energy Outlook 2007 (AEO2007). FMPA believes that there will be adequate supply of natural gas. The incremental addition of natural gas recovered from available leasing and development areas along with natural gas from new leasing and development areas, would serve as a potential natural gas resource for the Cane Island 4. Based on the pricing forecast established for transporting natural gas into the Florida Reliability Coordinating Council region, the sources of natural gas located in the lower 48 Outer Continental Shelf and new onshore production provide reasonable assurance of the adequate availability of natural gas for Cane Island 4.

Q. How will liquefied natural gas (LNG) contribute to the availability of natural gas for Cane Island 4?

A. With US natural gas production remaining relatively constant, imports of natural gas are projected to increase to meet the growing power generation demand of domestic consumption. Most of the expected growth in US natural gas imports is expected to be in the form of LNG. The expansion of LNG supplies after 2012 will increase the probability for Cane Island 4 to receive natural gas from LNG terminals located in the southeastern United States.

– **Q. How have recent proven natural gas reserves compared to historical levels?**

– A. As of December 31, 2006, proven natural gas reserved were at the highest level since 1976. Proven reserves of natural gas increased by 3 percent from 2005 to 2006.

–

Q. Please discuss natural gas pipeline and storage infrastructure as it relates specifically to Florida.

A. The southeastern portion of the United States accounts for approximately 38,127 total miles of pipelines, with the State of Florida accounting for 4,746 miles of pipeline. The total Florida pipeline capacity is served by four companies: Florida Gas Transmission (FGT), GulfSouth Pipeline, Gulfstream Natural Gas System, LLC (Gulfstream), and Southern Natural Gas. In addition, natural gas storage facilities are being developed along the Gulf Coast in numerous locations in close proximity for serving the State of Florida. Current gas transportation capacity serving the State of Florida on these four pipelines is fully subscribed. The additional demand caused by future power generation projects like Cane Island 4 in Florida will require pipeline capacity expansions. FGT has already announced a significant expansion of its facilities and other expansions are currently being evaluated. These four pipelines current and proposed transportation capacity, along with the existing and proposed storage facilities, will provide adequate natural gas transportation and storage capacity for the Florida market.

Q. Please describe the natural gas storage facilities that will serve the Florida market.

A. There are a number of natural gas storage facilities under development and in operation that will serve the Florida market. The Floridian Natural Gas Storage Company LLC (FGS) facility is proposed and will be located in an industrial area near Indiantown in Martin County, Florida. The FGS facility will consist of two aboveground LNG storage tanks, each capable of storing up to 4 billion cubic feet (Bcf) of natural gas; refrigeration compressors to cool the gas; and re-gasification equipment. Natural gas will be delivered to and from FGS using both the FGT and Gulfstream natural gas pipeline systems. FGS is expected to begin commercial operation in mid-2011 as currently proposed.

Southern Pines Energy Center is being developed as a FERC-regulated natural gas storage facility in Greene County, Mississippi. The project site has the capability to develop up to five 8 Bcf caverns for a total working gas capacity of 40 Bcf. The first cavern entered commercial operation on May 1, 2008 with a second cavern planned for commercial operation later this year. A third cavern is currently scheduled for commercial operation in 2010. FMPA will have 1 Bcf of capacity in this facility by the time Cane Island 4 is constructed. This storage will provide significant capabilities for daily operations and provide supply source reliability during gas supply production interruptions.

MoBay Storage Hub LLC will provide high-deliverability, multicycle (HDMC) gas storage services to the Southeast market. MoBay is located in Mobile

County, Alabama and will initially connect with four major interstate pipelines systems serving the Southeast and Northeast markets. Currently, the combined pipeline takeaway capacity at MoBay is 6.9 Bcf per day to the east and 3.9 Bcf per day to the west. MoBay would be the most southeasterly HDMC storage facility in the United States and the only storage facility directly connected to the Gulfstream Natural Gas System. The proposed MoBay compressor station will be located directly adjacent to Gulfstream Station 410 in Mobile County, Alabama. Working gas capacity will be 50 Bcf, with maximum injection and withdrawal capability of 1 Bcf per day.

Bay Gas Storage operates two high-deliverability, natural gas, salt dome storage caverns located in the northeastern corner of Mobile County, Alabama with a combined total working gas capacity of 6.0 Bcf. Total injection capacity at the facility is 200 million cubic feet (MMcf) per day, and withdrawal capacity is 610 MMcf per day. A third storage cavern is currently under development and is expected to be operational by spring 2008; this cavern will add approximately 5.0 Bcf of working gas capacity. Injection capacity at this cavern will be 250 MMcf per day, and withdrawal capacity will be 600 MMcf per day. Total working gas capacity will increase from 6.0 Bcf to 11.0 Bcf upon completion of the third cavern.

Q. Are there other proposed projects that will benefit the Florida natural gas market?

A. Yes. The Southeast Supply Header, LLC (SESH) is a joint venture between subsidiaries of CenterPoint Energy, Inc. and Spectra Energy. The 270 mile,

36 inch and 42 inch diameter pipeline will have an estimated capacity of 1 Bcf per day. The pipeline will extend from the Perryville Hub in northeastern Louisiana to Gulfstream in southern Mobile County, Alabama, and will have two interconnects with FGT, yielding a capacity of over 1 Bcf per day into each pipeline.

Q. Will the addition of Cane Island 4 require FMPA to construct any new natural gas pipelines?

A. No. The Cane Island site is currently served by two separate existing natural gas pipelines – one owned by FGT and one owned by Gulfstream Natural Gas System, LLC (Gulfstream).

Q. Please describe Gulfstream.

A. The Gulfstream system consists of a 691 mile pipeline that was placed in service in May 2002. Gulfstream can serve customers on both the east and west coasts of Florida, as well as the interior of the peninsula. The Gulfstream system went into service with an initial capacity of 1.1 Bcf per day of gas.

Q. Does FMPA anticipate that Gulfstream will have adequate natural gas delivery capacity to reliably serve Cane Island 4?

A. Yes. Gulfstream has undertaken several system extensions/expansions since its initial in-service date of May 2002. Most recently, Gulfstream conducted an Open Season from June 1 to August 31, 2007, to gauge market interest in an expansion of its existing natural gas pipeline system. The expansion was

designed for up to 750,000 MBtu per day of incremental firm transportation service. Since then, Gulfstream has reduced their proposed expansion by approximately 50 percent of the initial design, with a proposed expansion capacity of between 350,000 and 450,000 MBtu per day.

Q. What is the planned in-service date for the proposed Gulfstream expansion?

A. The new service from the mainline expansion is anticipated to be available in late 2011 to 2012. Gulfstream has indicated that they would be able to supply 30,000 to 45,000 MBtu per day of firm capacity for Cane Island 4 prior to the in-service date of the mainline expansion if such provision was necessary for Cane Island 4.

Q. Has FMPA explored the potential acquisition of firm natural gas transportation from the proposed Gulfstream expansion?

A. During the Open Season period, FMPA submitted a request for a volume of 20,000 MBtu per day of firm capacity to serve Cane Island 4. This submittal was a non-binding request for capacity. Subsequent discussions are ongoing to define the specific details of an arrangement which could lead to a binding Precedent Agreement between FMPA and Gulfstream for incremental capacity of up to approximately 45,000 MBtu per day.

Q. Please describe FGT.

A. FGT operates a 5,000 mile natural gas pipeline system that extends from south Texas to south Florida with a current mainline capacity of 2.1 Bcf per day. FGT's total receipt point capacity is in excess of 3.0 Bcf per day and includes interconnections with 10 interstate and 10 intrastate pipelines to facilitate receiving supplies of natural gas into its pipeline system. The pipeline has extensive access to diverse natural gas supplies, including the offshore Gulf of Mexico region.

Q. Does FMPA anticipate that FGT will have adequate natural gas delivery capacity to reliably serve Cane Island 4?

A. Yes. FGT has continuously added pipeline capacity to increase its ability to offer firm natural gas transportation service into the state of Florida and meet the growing demand for natural gas within the State. Most recently, FGT conducted an Open Season ending on February 15, 2008, for a proposed Phase VIII expansion project. The Phase VIII expansion is expected to provide an additional 0.8 Bcf per day, and bring the total capacity of FGT to 2.9 Bcf per day when completed. On February 11, 2008, FGT announced that Florida Power & Light Company (FPL) had agreed to become the anchor shipper of the proposed natural gas pipeline expansion project through a 25 year service agreement for 400 MMcf per day of capacity.

Q. Has FMPA explored the potential acquisition of firm natural gas transportation from FGT's proposed Phase VIII expansion?

A. During the Phase VIII Open Season period, FMPA submitted a request for firm capacity of 30,000 MBtu per day to serve Cane Island 4. This submittal was a nonbinding request for capacity. Subsequent discussions have occurred where FGT required a binding volume commitment from FMPA to meet its material commitment schedule. FMPA was not prepared to make a binding commitment in the timeline necessary to meet this requested deadline. As a result, FGT formally withdrew its offer of capacity to FMPA on May 1, 2008. However, FMPA is continuing to explore other available options for serving Cane Island 4 and anticipates no problems in meeting the incremental natural gas demand of this facility. Furthermore, FMPA has not ruled out acquiring firm natural gas transportation from FGT in the future.

Q. Are there any other natural gas transportation options that FMPA is pursuing for Cane Island 4?

A. Yes. There is the proposed East Coast Pipeline project being proposed by Peoples Gas Systems, a TECO Energy subsidiary. This proposed pipeline begins at the terminus of the Cypress Pipeline and runs along the east cost of Florida and then inland to provide service to the Orlando area and will terminate in the vicinity of the Cane Island Power Park. The project plans to interconnect with Gulfstream in close proximity of Cane Island Power Park. This new pipeline will have a capacity of approximately 300 MMcf/d. The Cypress Pipeline supplies LNG from Southern Natural's Elba Island LNG facility. Cane

Island 4 would be supplied by BP Energy, who is discussing a bundled natural gas supply and transportation deal with FMPA.

Q. Has FMPA made any final decisions related which natural gas transportation system will be used to serve Cane Island 4?

A. No. At this time, FMPA is continuing to evaluate both the amount of incremental firm natural gas transportation capacity needed to serve Cane Island 4 and which pipeline system will provide the best alternative for such service.

Q. Is FMPA confident in its ability to secure firm natural gas transportation capacity to reliably serve the needs of Cane Island 4?

A. Yes. With the proposed natural gas supply expansion projects under way throughout the State of Florida, FMPA is confident that adequate natural gas transportation capacity will be available to provide reliable service for Cane Island 4. The site being served by both FGT and Gulfstream offers FMPA the opportunity to choose and/or reallocate gas transportation capacity to select the best option available. The construction of a new generating unit in an area served by two pipelines enhances the reliability of delivering natural gas to Cane Island 4.

Q. Have the costs associated with firm natural gas transportation been accounted for in the economic evaluations presented in the Cane Island 4 Need for Power Application?

A. Yes. The costs associated with incremental firm natural gas transportation capacity are discussed in the testimony of Mr. Bradley Kushner.

Q. How will Cane Island 4 be interconnected to the transmission system.

A. Cane Island 4 will be interconnected to the existing Cane Island Substation. The Cane Island substation is served by four 230 kV transmission lines including a 230 kV transmission line to TECO's Osceola Substation, a 230 kV transmission line to OUC's Taft Substation, a 230 kV transmission line to Kissimmee Utility Authority's Clay Street Substation, and a 230 kV transmission line to PEF's Intercession City Substation.

Q. Has FMPA requested Network Resource Interconnection Service (NRIS) from PEF for Cane Island 4?

A. Yes. FMPA has requested NRIS from PEF and PEF approved NRIS for Cane Island 4 on March 31, 2008.

Q. Has the FRCC reviewed the addition of Cane Island 4 to the transmission system?

A. Yes. The FRCC's Transmission Working Group (TWG) and Stability Working Group (SWG) have reviewed the study conducted by FMPA for the interconnection and integration of FMPA's Cane Island 4 based on the 2007

FRCC databank. Based on the review and analysis conducted by the TWG and SWG, the FRCC Planning Committee determined on April 2, 2008 that the proposed interconnection and integration plan will be reliable, adequate and will not adversely impact the reliability of the FRCC transmission system.

Q. Has FMPA explored the opportunity to install solar PV capacity throughout the ARP member cities?

A. Yes. FMPA issued a request for proposals specifically for solar PV equipment or purchase power agreements (Solar RFP) on December 5, 2007.

Q. Please describe the Solar RFP.

A. The Solar RFP invited bidders to submit bids for the installation of 10 MW of solar PV capacity by the end of 2008, with the potential for up to 100 MW of solar PV capacity by 2013. Bidders were allowed to submit proposals ranging from the supply of PV equipment, to the installation of turnkey solar project, to a power purchase contract for energy generated by a solar system.

Q. Did FMPA receive any bids in response to the Solar RFP?

A. Yes. Twenty-six bids, some with multiple offerings, were received – 12 offering a power purchase agreement (PPA), 13 offering turnkey, or EPC, installation of the equipment, and 7 offering to sell the equipment directly.

Q. How were these bids evaluated by FMPA?

A. FMPA solicited the expertise of OUC staff and the staff of the Florida Solar Energy Center (FSEC) to be on a bid review team. The team met in January 2008 to review and rank the bids received in response to the solar RFP. The results of the review team meeting were compiled and finalized.

Q. What were the results of the bid evaluation process?

A. All of the proposals were found to be above FMPA's avoided costs and therefore more expensive than traditional resources. However, FMPA is continuing to explore the potential use of solar technology as part of its commitment to develop a balanced mix of power resources including renewable technologies such as solar energy.

Q. Is FMPA currently considering any of these bids?

A. Yes. FMPA's Executive Committee approved the ranking of proposals developed following FMPA's evaluations. On April 4, 2008, FMPA staff issued an e-mail soliciting interest from FMPA's ARP member cities to identify those members which might have an interest in locating a solar photovoltaic (PV) installation in their community. The various sites selected will require the execution of agreements between the property owner, FMPA, and the contractor. FMPA staff is currently working with one of the bidders to develop a contract to bring to the ARP Executive Committee for their approval in May 2008.

Q. Please describe FMPA's existing conservation and demand-side management (DSM) programs.

A. As a wholesale electricity provider, FMPA does not directly provide conservation and DSM programs to retail customers. The ARP members, however, provide numerous conservation and DSM programs to their customers. The following lists some of the programs provided.

- Energy audits
- Energy saving tips
- Appliance and other rebates
- Load profiling for commercial customers
- Fix-up programs
- Tree planting incentives
- On-line energy audits
- Compact fluorescent bulbs
- ESCO projects
- City wide energy conservation programs
- Energy Star
- LED traffic signals

These programs are described in detail in Section 17.0 of the Cane Island Unit 4 Need for Power Application Exhibit No.__[FMPA-1].

Q. Has FMPA made an effort to identify additional DSM measures?

A. Yes. FMPA conducted an innovative request for proposals (RFP) process for DSM resources. That process is discussed in the pre-filed testimony of Mr. Nicholas Guarriello.

Q. Is FMPA pursuing other conservation and DSM measures not identified in the RFP for DSM resources?

A. Yes. FMPA is pursuing a number of other conservation and DSM measures. One innovative program that FMPA has been working on is a demand response program with Publix Super Markets. This program would use Publix's standby generators to reduce FMPA's peak demand. Since these standby generators must be exercised periodically, their use to reduce FMPA's demand displaces FMPA generation and reduces FMPA's CO_2 and other emissions.

Q. How does FMPA support the ARP members in their conservation and DSM programs?

A. FMPA supports the ARP member conservation and DSM programs in a number of ways. FMPA provides conservation and DSM training for the ARP members. In addition, FMPA participates in numerous organizations and associations that provide assistance to utilities in developing and operating conservation and DSM programs. FMPA administers a contract with an energy services company (ESCO) which works directly with ARP member commercial and industrial customers to develop programs to reduce demand and energy. Section 17.0 of the Cane Island 4 Need for Power Application Exhibit No.__ [FMPA-1]

describes in detail ways in which FMPA assists the ARP members in implementing conservation and DSM programs.

Q. Have conservation measures been utilized by FMPA and the ARP members to the extent reasonably available?

A. Yes. The ARP members are providing numerous conservation and DSM measures. FMPA has done a thorough test of the available market for DSM through its RFP process and is currently pursuing the reasonably available alternatives.

Q. Are there conservation measures reasonably available to FMPA and the ARP members that mitigate the need for Cane Island 4.

A. No. Cane Island 4 is still needed by FMPA even after the existing and reasonably available conservation measures are considered.

Q. Does this conclude your testimony?

A. Yes.

Pre-Filed Testimony, Reedy
Page 6, Lines 21-22

Change " owned by Fort Pierce Utilities Authority, Lake Worth, and "

To

" owned by Lake Worth and "

Pre-Filed Testimony, Reedy
Page 6, Line 23

Change " is 250 MW. "

To

" is **136** MW. **In addition to the planned retirements, the Fort Pierce generating units with a total summer capacity of 114 MW were retired during the first half of 2008 and demolition of these units has begun.**"

Pre-Filed Testimony, Reedy
Page 16, Line 17-18

Change "Yes. FMPA has requested NRIS from PEF and PEF approved NRIS for Cane Island 4 on March 31, 2008."

To

"No. NRIS was not requested under the Open Access Transmission Tariff (OATT). FMPA requested that Cane Island 4 be served as a new resource under the existing transmission service agreement with Progress Energy Florida (PEF), and PEF approved this request on March 31, 2008."

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF JONATHAN P. NUNES

ON BEHALF OF

FLORIDA MUNICIPAL POWER AGENCY

DOCKET NO. _____

MAY 7, 2008

Q. Please state your name and business address.

A. My name is Jonathan P. Nunes. My business address is 1000 Legion Place, Suite 1100, Orlando, Florida 32801.

Q. By whom are you employed and in what capacity?

A. I am employed by R. W. Beck as a Senior Economist.

Q. Please describe your responsibilities in that position.

A. As a Senior Economist in R. W. Beck's Generation Planning and Analysis practice, I am responsible for providing consulting services in the areas of power supply planning, financial planning and analysis, and modeling and systems analysis. In particular, I have been responsible for numerous load forecasts in support of power supply decisions, power plant need filings, wholesale and retail rate planning, and budgeting for a variety of municipal and cooperative utilities throughout the United States.

Q. Please describe R. W. Beck.

A. R. W. Beck is a national management consulting and engineering firm with a multi-disciplined staff of 550 with 26 offices in North America and one in Singapore. R. W. Beck provides a variety of consulting and engineering services across several industries, including energy, water, and solid waste. For the energy industry, R. W. Beck provides power supply analysis, assistance with Request for Power Supply Proposals (RFPs), independent engineering reviews and financial feasibility assessments, appraisal evaluations, due diligence reviews, transmission and distribution design services, construction management, planning and owner's engineering services for generation and transmission facilities, preparation of environmental reports, monitoring, permitting, and licensing. Since its founding in 1942, some of the milestones that the firm has achieved include:

- Provided independent engineering and feasibility assessments associated with over $150 billion in capital investment.
- Performed due diligence reviews and/or designed and engineered over 400 power-related projects.

Q. Please state your educational background and professional experience.

A. I received a Bachelor of Science degree in Business Administration, Economics from the University of Central Florida. I also received a Master of Arts degree in Applied Economics from the University of Central Florida. I have over 14 years of experience in the utility industry.

Q. Have you previously testified before the Florida Public Service Commission?

A. Yes. In the Taylor Energy Center Need for Power, my testimony regarding FMPA's load forecast was stipulated to by all Parties.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to summarize the forecast of electrical power demand and energy consumption for the Florida Municipal Power Agency (FMPA) All-Requirements Project (ARP) developed by R. W. Beck. This summary will include a brief description of the methodology of the forecast, as well as the projected annual growth rates for summer and winter peak demand and net energy for load.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. Exhibit No. __ [JPN-1] is a copy of my résumé.

Q. Are you sponsoring any sections of Exhibit No. __ [FMPA-1], the Cane Island 4 Need for Power Application?

A. Yes. I am sponsoring Section 5.0, which was prepared under my direct supervision.

Q. Please briefly describe the methodology used to develop the load forecasts for the All-Requirements Project.

A. The ARP Load Forecast relies on an econometric approach to project electric sales by major rate classification in the service territories of the ARP Members. Econometric forecasting makes use of regression analysis to establish historical relationships between energy consumption and various explanatory variables based on fundamental economic theory and experience. These historical models are evaluated and selected on their statistical ability to explain variations in energy usage. The resulting models are then simulated using projections of the explanatory variables to produce forecasts of energy sales. Forecasts of net energy for load and peak demand are then derived from the energy sales forecast based on assumed loss and load factors, generally based on recent historical averages of these factors. Finally, the total ARP energy requirements and peak demand are based on summations of these load determinants across the Members supplied by the ARP and, in the case of coincident peak demand, assumed coincidence factors generally based on recent historical averages. Sections 5.4 through 5.7 of Exhibit No. __ [FMPA-1] summarize the general methodology used to forecast load for each rate classification.

Q. Are there any changes to the ARP Members during the forecast period?

A. Yes. The City of Vero Beach has provided FMPA with its *Notice of Establishment of Contract Rate of Delivery* (CROD). The load forecast was developed assuming that Vero Beach's CROD becomes effective January 1, 2010. The effect of the notice on the forecast is that Vero Beach's load will no

longer be included in the ARP load forecast once Vero Beach's CROD becomes effective. Also, the City of Fort Meade is included in the forecast beginning January 2009, at which time the ARP will begin serving its electricity needs.

Q. Please summarize the ARP's Base Case forecast summer peak demand.

A. The forecast 2008 summer peak demand is 1,545 MW, and the 2026 forecast summer peak demand is 2,077. The summer peak demand is projected to grow at a rate of 3.2 percent from 2008 to 2009, which reflects the addition of Fort Meade, and at an average annual rate of 2.2 percent for 2010 through 2026.

Q. Please summarize the ARP's Base Case forecast winter peak demand.

A. The forecast 2008 winter peak demand is 1,427 MW, and the forecast 2026 winter peak demand is 1,878 MW. The winter peak demand is projected to grow at a rate of 3.2 percent from 2008 to 2009, which reflects the addition of Fort Meade, and at an average annual rate of 2.2 percent from 2010 through 2026.

Q. What is the ARP's Base Case forecast net energy for load?

A. The forecast 2008 net energy for load is 7,655 GWh and the forecast net energy for load in 2026 is 10,233 GWh. The NEL is expected to grow at a rate of 3.1 percent from 2008 to 2009, which reflects the addition of Fort Meade, and at an average annual rate of 2.2 percent from 2010 to 2026.

Q. How are the changes to ARP members discussed previously in your testimony reflected in the peak demand and net energy for load projections you just summarized?

A. The growth rate from 2008 to 2009 includes the addition of the Fort Meade load following expiration of its existing full requirements agreement with TECO as discussed above. Growth rates have been shown separately for the 2008 to 2009 and 2010 through 2026 periods to avoid distortion due to Vero Beach's establishment of CROD, effective January 1, 2010. All values decrease from 2009 to 2010 as a result of the removal of Vero Beach loads beginning in 2010.

Q. Were any alternative load forecasts developed?

A. Yes. In addition to the Base Case forecast that I just described, high and low case projections were developed to reflect various assumptions regarding future levels of population and economic activity. These high and low case forecasts are intended to capture 90 percent of the uncertainty in these long-term driving variables (1.7 standard deviations). Summaries of the results of the high case and low case forecasts are presented in Table 5-4 of Exhibit No. __ [FMPA-1].

Q. In your opinion, are the assumptions used in the load forecasts reasonable for planning purposes?

A. Yes. The methodology used to estimate and simulate the forecasting equations is commonly accepted and widely used in the utility industry. The estimated parameters of the forecasting equations benchmark well against economic theory and the results of similar analyses done elsewhere. Economic data was

provided by Economy.com, a nationally-recognized provider of such data. Historical and normal weather data, on which the load forecast is based, were provided by the National Oceanic and Atmospheric Administration, a widely used source for weather data.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF MYRON R. ROLLINS

ON BEHALF OF

FLORIDA MUNICIPAL POWER AGENCY

DOCKET NO. _____

MAY 7, 2008

Q. Please state your name and business address.

A. My name is Myron R. Rollins. My business address is 11401 Lamar Avenue, Overland Park, Kansas 66211.

Q. By whom are you employed and in what capacity?

A. I am employed by Black & Veatch Corporation. My current position is Director.

Q. Please describe your responsibilities in that position.

A. I am responsible for the management of various projects for utility and non-utility clients. These projects encompass a wide variety of services for the power industry. The services include load forecasts, conservation and demand-side management, reliability criteria and evaluation, development of generating unit addition alternatives, fuel forecasts, screening evaluations, production cost simulations, optimal generation expansion modeling, economic and financial evaluation, sensitivity analysis, risk analysis, power purchase and sales evaluation, strategic considerations, analyses of the effects of environmental

regulations, feasibility studies, qualifying facility and independent power producer evaluations, power market studies, and power plant financing.

Q. Please describe Black & Veatch.

A. Black & Veatch Corporation has provided comprehensive engineering, consulting, and management services to utility, industrial, and governmental clients since 1915. Black & Veatch specializes in engineering, consulting, and construction associated with utility services, including electric, gas, water, wastewater, telecommunications, and waste disposal. Service engagements consist principally of investigations and reports, design and construction, feasibility analyses, rate and financial reports, appraisals, reports on operations, management studies, and general consulting services. Present engagements include work throughout the United States and numerous foreign countries.

Q. Please state your educational background and experience.

A. I received a Bachelor of Science degree in Electrical Engineering from the University of Missouri – Columbia. I also have two years of graduate study in Nuclear Engineering at the University of Missouri – Columbia. I am a licensed professional engineer and a Senior Member of the Institute of Electrical and Electronic Engineers.

I have 32 years of experience in the power industry specializing in generation planning and project development. In the past ten years, I have been the project manager for over 100 projects, the vast majority of which have been for Florida

utilities. Florida utilities for which I have worked include Florida Municipal Power Agency (FMPA), Kissimmee Utility Authority, Lakeland Electric, Orlando Utilities Commission (OUC), JEA, City of Tallahassee, Reedy Creek Improvement District, City of St. Cloud, Utilities Commission of New Smyrna Beach, Sebring Utilities Commission, City of Homestead, Florida Power Corporation, Tampa Electric Company, and Seminole Electric Cooperative.

I was responsible for the development of Black & Veatch's POWRPRO chronological production costing program and POWROPT optimal generation expansion program. I am also responsible for power market analysis and project feasibility studies. I have been responsible for supporting need for power petitions on a number of power plants in Florida including Stanton 1, 2, A, and B; Cedar Bay; Cane Island 3; McIntosh 5; the Brandy Branch Combined Cycle Conversion, and Treasure Coast Unit 1;. I also participated in the need for power proceeding for the Hardee and Hines projects. I have presented expert testimony on several occasions before the Alaska, Indiana, Missouri, and Florida public service commissions and have presented numerous papers on strategic planning and cogeneration.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to provide an overview and summary of the Cane Island 4 Need for Power Application, Exhibit No. __ [FMPA-1]. In addition to this general summary, I will discuss the economic parameters used in the economic analyses of Cane Island 4. I will provide an overview of the Cane

Island 4 project and discuss considerations made in determining not to include fuel oil backup on the proposed unit. I will also discuss the reliability criteria used by FMPA and the projected need for additional capacity to satisfy these criteria.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. Exhibit No. __ [MRR-1] is a copy of my résumé. Exhibit No. __ [MRR-2] is a summary of the Cane Island 4 capital cost estimate. Exhibit No. __ [MRR-3] is a summary of the Cane Island 4 estimated performance.

Q. Are you sponsoring any sections of the Cane Island 4 Need for Power Application, Exhibit No __ [FMPA-1]?

A. Yes. I am sponsoring Sections 1.0, 2.0, 4.0, 9.0, 10.0, 12.0, and 13.0, all of which were prepared by me or under my direct supervision.

Q. Please summarize the Cane Island 4 Need for Power Application, Exhibit No. __ [FMPA-1].

A. FMPA is submitting the Cane Island 4 Need for Power Application in support of a proposed natural gas-fired "combined cycle" electric generating unit to be located at the existing Cane Island generating station in Osceola County, Florida.

Exhibit No. __ [FMPA-1] presents the results of a comprehensive analysis that was performed to demonstrate that the proposed Cane Island 4 satisfies all of the statutory criteria set forth in Section 403.519 Florida Statutes.

Q. Please discuss these statutory criteria.

A. Section 403.519(3), Florida Statutes, sets forth the following criteria which the Commission must consider in making need determinations:

- The need for electric system reliability and integrity.
- The need for adequate electricity at a reasonable cost.
- The need for fuel diversity and supply reliability.
- Whether the proposed plant is the most cost-effective alternative available.
- Whether renewable energy sources and technologies, as well as conservation measures, are utilized to the extent reasonably available.
- Whether there are conservation measures taken by or reasonably available to the applicant or its members which might mitigate the need for the proposed plant.

Q. Please summarize the process used to determine that Cane Island 4 met each of these statutory criteria.

A. FMPA went through a multistage evaluation process to ensure the proposed Cane Island 4 is consistent with the criteria in Section 403.519(3).

The first step involved developing detailed cost and performance estimates for Cane Island 4. These estimates are presented in Section 9.0 of Exhibit No. __[FMPA-1] and are discussed in more detail later in my testimony.

The second step involved the development of cost and performance estimates for numerous natural gas-fired supply-side alternatives to Cane Island 4. These supply-side alternatives included simple cycle combustion turbines and a combined cycle alternative identical to the proposed Cane Island 4. These alternatives are discussed in the testimony of Mr. Bradley Kushner.

FMPA issued four separate requests for proposals (RFPs) to identify alternatives to the construction of the proposed Cane Island 4. These four RFPs included a power supply RFP soliciting proposals for purchase power, an RFP soliciting renewable sources of capacity and energy; an RFP seeking demand-side management (DSM) services; and an RFP for solar photovoltaic resources. The RFP processes are discussed in the testimony of Mr. Nicholas Guarriello and Mr. Thomas Reedy.

Detailed economic evaluations were performed to evaluate the proposed Cane Island 4 as well as the bids received in response to the four RFPs. The methodology and results of these evaluations are discussed in the testimony of Mr. Bradley Kushner. As Mr. Kushner explains in detail, construction of Cane Island 4 in May 2011 represents the most cost-effective resource addition under all of the scenarios and sensitivities evaluated, which included consideration of

new renewable and demand-side management projects identified in the RFP's and being considered by FMPA.

Q. Please describe the economic parameters used in the Cane Island 4 Need for Power Application, Exhibit No. __ [FMPA-1].

A. A 2.3 percent annual general inflation rate was used. Escalation rates of 2.3 percent annually were used for capital and O&M costs. An annual rate of 5.0 percent was used for the long-term tax-exempt bond interest rate, interest during construction rate, and present worth discount rate. Alternatives were evaluated over a 20 year planning period from 2008 through 2027.

Q. What is the fixed charge rate?

A. The fixed charge rate (FCR) represents the sum of a project's fixed charges as a percent of the initial investment cost. When the FCR is applied to the initial investment, the product equals the revenue requirements needed to offset the fixed charges during a given year.

Q. What were the financing terms used in your assumptions?

A. Simple cycle combustion turbines were assumed to have a 25 year financing term, while natural gas fired combined cycle units were assumed to be financed over 30 years.

Q. What fixed charge rates were used in the evaluation of Cane Island 4?

A. The levelized FCR calculations assume a 2.0 percent bond issuance fee, an assumed 0.50 percent annual property insurance cost, and a debt service reserve fund equal to 100 percent of the average annual debt service requirement earning interest at an interest rate equal to the bond interest rate. The resulting 25 year fixed charge rate is 7.824 percent and the 30 year fixed charge rate is 7.194 percent.

Q. Are these economic parameters appropriate for use in this Need for Power Application?

A. Yes. They are consistent with economic parameters that we have been using in similar evaluations before the Commission and more importantly, they are internally consistent across all the evaluations.

Q. Please describe the proposed Cane Island 4 project.

A. The proposed Cane Island 4 is a 1x1 F class combined cycle unit with a nominal rating of 300 MW at average temperature conditions. The unit will be installed at the existing Cane Island Power Park (CIPP) site which is located near Intercession City, in Osceola County, Florida. The unit will be interconnected with the existing CIPP substation.

Cane Island 4 will include supplemental firing and evaporative cooling. The unit will include steam turbine bypass to the condenser to allow operation in simple cycle mode if an extended steam turbine generator outage occurs.

Cooling tower makeup will be provided by Toho Water Authority via an existing pipeline. In addition, four new onsite wells will be provided for backup cooling tower makeup water supply. Cooling tower blowdown and other process wastewaters will be returned to the Toho Water Authority pipeline.

Q. How was the Cane Island 4 capital cost estimate developed?

A. The capital cost estimate was based on building a new 1x1 7FA combined cycle generating unit at the existing CIPP near Intercession City, Florida. The capital cost estimate includes direct costs for purchased equipment and materials, construction contract costs, and indirect costs. Direct costs include the costs associated with the purchase of equipment, erection, and all contractor services.

Construction costs were developed on the basis of an EPC contract. It was assumed that construction would be performed using a 50 hour work week, with some 60 hour work weeks. Local labor craft rates used included payroll, payroll taxes, and benefits. Construction indirects and construction equipment costs were included in the construction and service contracts portion of the estimate.

Indirect costs associated with construction were included in the base cost estimate. General indirect costs included all necessary services required for checkouts, testing services, and commissioning. Insurance for general liability was included. Contractor engineering, contractor field construction management, technical direction, contingency, profit, equipment transportation

costs, startup, and commissioning were also included. Owner's costs were estimated on the basis of FMPA's experience with other similar projects.

Q. What is the resulting capital cost estimate for Cane Island 4?

A. The capital cost estimate for Cane Island 4 is approximately $421,600,000. This estimate includes equipment costs, EPC costs (direct and indirect), project contingency, and owner's costs. The capital cost estimate also includes interest during construction and is representative of an installed, in-service cost estimate for May 2011 commercial operation of Cane Island 4. The capital cost estimate in presented in Exhibit No. __ [MRR-2].

Q. Please summarize the operating and maintenance (O&M)cost estimates developed for Cane Island?

A. Fixed and nonfuel variable O&M cost estimates were developed for Cane Island 4. Fixed costs include labor, payroll burden, fixed routine maintenance, and administration costs. Variable O&M costs include consumables, chemicals, lubricants, water, and major inspections and overhauls.

The fixed O&M cost estimate for Cane Island 4 is $4.56/kW-year, and the nonfuel variable O&M cost estimate for Cane Island 4 is $3.30/MWh. These estimates are presented in 2008 dollars.

Q. Please summarize the estimated performance of Cane Island 4.

A. Performance estimates were developed for various ambient conditions at various load points. Non-recoverable output and net plant heat rate (NPHR) degradation factors were applied to the new-and-clean net output and NPHR estimates. The resulting degraded net plant output and NPHR estimates are summarized in Exhibit No. __[MRR-3].

Q. Will Cane Island 4 be designed to operate on fuel oil as a backup fuel source?

A. No. In reviewing the projected operation of Cane Island 4, FMPA has concluded that the potential reliability benefits of including oil backup capability in this unit are overshadowed by the incremental costs, maintenance, and limited reliability benefits associated with this capability.

Q. Are there any State or Federal requirements for oil backup capability?

A. No.

Q. Will fuel supply reliability be maintained for Cane Island 4 without having dual fuel capability?

A. Yes. Historically, utilities proposed dual fuel capability because natural gas was supplied to Florida through a single natural gas pipeline. The single pipeline was subject to disruptions affecting the supply for all the natural gas usage in the state. The possibility of natural disasters (such as hurricanes that could affect the predominant supply source in the Gulf of Mexico) has caused concern of

natural gas curtailments within Florida. However, as the natural gas transportation network has expanded and supply sources and storage have become more diverse, the probability that a hurricane or other natural disaster could or would disrupt natural gas supplies to the state has decreased.

Q. Has the FPSC approved need applications for other natural gas fueled projects that do not include oil backup?

A. Yes. The FPSC approved Florida Power & Light Company's Manatee Unit 3 project without oil backup. Like the Cane Island site, Manatee Unit 3 has access to natural gas transportation service from both FGT and Gulfstream. Access to dual pipelines dramatically increases the reliability of natural gas supplies.

Q. Was the incremental capital cost for fuel oil backup been estimated for Cane Island 4?

A. Yes. The incremental capital cost for dual fueled capability for Cane Island 4 was estimated to be approximately $13.0 million. Several additional problems with dual fuel operation could be quantified and would result in significant additional cost when viewed from the utility's perspective.

Q. Were other non-price related factors considered in determining not to include oil backup for Cane Island 4?

A. Yes. Although oil backup for generating units may potentially enhance system reliability, there is a limit to the value in requiring that all units include this capability. In the event of a total and prolonged gas outage, many units that

have oil backup will not be able to operate as required because of the extreme difficulty in continuously providing fuel oil by truck. Recent improvements to the Florida natural gas supply network have also increased the diversity and reliability of the gas supply, further reducing the need for dual fuel capability on every new natural gas fueled generating unit proposed in the State.

Other specific factors taken into consideration related to inclusion of oil backup include:

- Increased demineralized water consumption resulting from water injection when operating on fuel oil.
- Increased air permitting requirements and greater emissions.
- Increased operations and maintenance costs to maintain and test the added equipment including test firing on fuel oil.
- Increased permit requirements due to increased water consumption and wastewater disposal.
- Increased environmental compliance requirements during operation of the plant.
- Increased probability of forced outage due to increased equipment complexity.
- Deterioration of stored fuel resulting in chance of failure when switching to fuel oil or starting on fuel oil.

Q. How reliable has the natural gas supply been to the Cane Island Power Park?

A. Very reliable. Since the first unit went into operation at Cane Island in 1995, oil has only been burned a total of 77 hours. That is equivalent to an additional forced outage rate of only 0.07 percent.

Q. Do FMPA's other natural gas units have oil backup.

A. Yes.

Q. How does Cane Island 4 relate to FMPA's planning reserve margin?

A. The capacity from Cane Island 4 will be equivalent to approximately 19.9 percent of FMPA's projected 2011 summer demand. Thus Cane Island 4 is essentially equal to FMPA's reserve margin and the loss of the unit will generally not affect FMPA's ability to serve load.

Q. How does FMPA determine its reserve requirements?

A. FMPA determines its reserve requirements by comparing net system capacity and system peak demand plus reserves for the summer and winter peaks. FMPA adheres to a minimum 18 percent reserve margin in summer and a minimum 15 percent reserve margin in winter. The planning reserve margin covers uncertainties in extreme weather, forced outages for generators, and uncertainty in load forecasts. FMPA plans to maintain the 18 percent reserve margin only for firm load obligations. Interruptible load and curtailable load are not considered in setting the 18 percent reserve margin.

Q. Please describe FMPA's expected need for additional capacity to satisfy reserve margin requirements under the base case load forecast.

A. Based on FMPA's existing and approved/planned capacity resources (discussed in the testimony of Mr. Thomas Reedy) and the base case load forecast (discussed in the testimony of Mr. Jonathan Nunes), FMPA is projected to require additional capacity to maintain its 18 percent summer reserve margin beginning in the summer of 2010. By the summer of 2011, FMPA's reserve margin is projected to fall to negative 1.3 percent, or 286 MW below the capacity required in order to maintain an 18 percent reserve margin. Projected summer capacity deficits continue to increase beyond 2011, growing to an estimated deficit of 363 MW by 2012.

Q. Does this conclude your pre-filed testimony?

A. Yes.

Pre-Filed Testimony, Rollins
Page 8, Line 3-5.

Change "and a debt service reserve fund equal to 100 percent of the average annual debt service requirement"

To

"and **a 6 month debt service reserve fund**."

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF JASON L.WOLFE

ON BEHALF OF

FLORIDA MUNICIPAL POWER AGENCY

DOCKET NO. _____

MAY 7, 2008

Q. Please state your name and business address.

A. My name is Jason Wolfe. My business address is 1000 Legion Place, Suite 1100, Orlando, Florida 32801.

Q. By whom are you employed and in what capacity?

A. I am employed by R.W. Beck. My current position is Senior Analyst.

Q. Please describe R.W. Beck.

A. R.W. Beck is a national management consulting and engineering firm with a multidisciplined staff of 550 with 26 offices in North America and one in Singapore. R.W. Beck provides a variety of consulting and engineering services across several industries, including energy, water, and solid waste. For the energy industry, R.W. Beck provides power supply analysis, assistance with requests for proposals (RFPs); independent engineering reviews and financial feasibility assessments; appraisal evaluations; due diligence reviews; transmission and distribution design services; construction management; planning and owner's engineering services for generation and transmission

facilities; preparation of environmental reports; and monitoring, permitting, and licensing. Since its founding in 1942, some of the milestones that the firm has achieved include the following:

- Providing independent engineering and feasibility assessments associated with more than $150 billion in capital investment.
- Performance of due diligence reviews and/or design and engineering of more than 400 power-related projects.

Q. Please state your educational background and experience.

A. I received a Bachelor of Science degree in Business Administration with a concentration in Finance from the University of Central Florida.

Since joining R.W. Beck in 2000, I have provided a wide range of consulting services, including quantitative risk assessments, wholesale power market studies, wholesale power cost projections, and financial analyses. I have also provided analytical support in legal and regulatory proceedings, including new generating resource need determination filings, and have been involved in the preparation of annual engineering reports.

Prior to joining R. W. Beck, I worked for one year as a financial analyst in the Combustion Turbine Engineering Department of Siemens Westinghouse Power Corporation.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to discuss the preliminary analysis of the ARP's historical carbon footprint for the years 1990 and 2000. In doing so I will discuss the methodology used to determine the ARP's carbon footprint. I will also discuss the current status of greenhouse gas regulation in the State of Florida.

Q. Are you sponsoring any sections of Exhibits to your testimony?

A. Yes. Exhibit No. ___ [JLW-1] is a copy of my resume.

Q. Are you sponsoring any sections of Exhibit No. ___[FMPA-1], the Cane Island Unit 4 Need for Power Application?

A. Yes. I am sponsoring Section 18.2, which was prepared by me.

Q. Please provide a summary of the current status of greenhouse gas emission regulation in Florida.

A. Greenhouse gas emissions currently are not regulated in Florida. On July 13, 2007, however, Governor Crist issued Executive Order Number 07-127, entitled "Immediate Action to Reduce Greenhouse Gas Emissions within Florida." Among other things, the order directed the Florida Department of Environmental Protection (DEP) to adopt rules requiring carbon dioxide (CO_2) emission reductions from electric utilities. As of the date of this filing, DEP has not adopted any such regulations.

Q. What are the CO_2 reduction targets set forth in Executive Order 07-127?

A. The Executive Order contemplates reductions of utility CO_2 emissions to 2000 levels by 2017, to 1990 levels by 2025, and to levels 80 percent lower than 1990 levels by 2050.

Q. Have you assessed the ARP's CO_2 emissions for the 1990 and 2000 baselines contemplated in Executive Order 07-127?

A. Yes. I calculated the historical CO_2 emissions for 1990 and 2000 for all 15 current ARP Members, regardless of the date each Member joined the ARP.

Q. What guidelines did you use to measure these historical CO_2 emissions?

A. Because DEP has not adopted guidelines for the reporting of greenhouse gases as of the date of this filing, the emissions inventory was performed using the guidelines set forth in the United States Department of Energy's (US DOE) final "Technical Guidelines Voluntary Reporting of Greenhouse Gases (1605(b)) Program" (Technical Guidelines or 1605(b) Guidelines), issued in January 2007.

Q. How do the 1605(b) Guidelines categorize emissions for electric utilities?

A. The 1605(b) Guidelines categorize emissions for electric utilities as occurring from either direct or indirect sources. Direct emissions are those emissions that the utility is directly responsible for producing; that is, the utility produces these emissions through operation of its own generating units. Indirect emissions are those emissions associated with purchased power.

Q. How does purchased power factor into carbon emission measurements?

A. To the extent the utility purchases energy from a specific generating resource, the emissions quantities can often be measured using the approach described for computing direct emissions. For other purchases, the 1605(b) Guidelines indicate that the purchasing utility should apply an EIA-provided regional emissions factor to the quantity of energy purchased to estimate the CO_2 emissions associated with the purchase(s).

Q. How were historical CO_2 emissions measured for FMPA?

A. In inventorying historical emissions quantities for the ARP Members, data availability was the key driver of the methodology chosen. Because the 1605(b) Guidelines identify continuous emissions monitoring system (CEMS) data as the most accurate source of emissions quantities, CEMS data was utilized wherever possible.

Q. Was it possible to capture all of the ARP's emissions data for the years 1990 and 2000 using CEMS data?

A. No. Because CEMS were not required to be installed on plants until after 1990, this data was not available for the 1990 computation. Additionally, some small generating units are not required to file CEMS data with the US EPA, so this data was not available for all generators for 2000. The CO_2 emissions associated with generating units for which CEMS data was not available were estimated using emissions factors specific to the appropriate fuel types.

Q. What is the ARP's resulting carbon footprint for the years 1990 and 2000 using the methodology you've described?

A. The ARP's total CO_2 emissions for 1990 and 2000 were approximately 3.48 million tons and 4.71 million tons, respectively.

Q. What steps is FMPA taking to reduce its carbon dioxide emissions?

A. Mr. Nicholas Guarriello discusses those efforts in his pre-filed testimony.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF NICHOLAS P. GUARRIELLO

ON BEHALF OF

FLORIDA MUNICIPAL POWER AGENCY

DOCKET NO. _____

MAY 7, 2008

Q. Please state your name and business address.

A. My name is Nicholas P. Guarriello. My business address is 1000 Legion Place, Suite 1100, Orlando, Florida 32801.

Q. By whom are you employed and in what capacity?

A. I am employed by R.W. Beck. My current position is Principal and Immediate Past President/CEO.

Q. Please describe R.W. Beck.

A. R.W. Beck is a national management consulting and engineering firm with a multidisciplined staff of 550 with 26 offices in North America and one in Singapore. R.W. Beck provides a variety of consulting and engineering services across several industries, including energy, water, and solid waste. For the energy industry, R.W. Beck provides power supply analysis, assistance with requests for proposals (RFPs); independent engineering reviews and financial feasibility assessments; appraisal evaluations; due diligence reviews;

transmission and distribution design services; construction management; planning and owner's engineering services for generation and transmission facilities; preparation of environmental reports; and monitoring, permitting, and licensing. Since its founding in 1942, some of the milestones that the firm has achieved include the following:

- Providing independent engineering and feasibility assessments associated with more than $150 billion in capital investment.
- Performance of due diligence reviews and/or design and engineering of more than 400 power-related projects.

Q. Please state your educational background and experience.

A. I received a Bachelor of Science degree in Electrical Engineering from the Polytechnic University. I have a Master of Business Administration from New York University. I am also a registered Professional Engineer in the State of Florida.

I have more than 35 years of experience in the electric, gas, solid waste, water, and wastewater industries. My experience includes financings, appraisals, retail rate studies, wholesale rate work, power supply planning, load forecasting, consulting engineer's reports for bond financing, contract analyses and negotiations, annual and biennial reports required by bond resolutions, and expert testimony and litigation support.

I also have significant experience in strategic and long-term planning for electric utility clients. I have been involved in several internal task forces and external presentations addressing the competitive and restructuring issues facing the utility industry in the United States, including transmission access, deregulation, technological improvements, and retail wheeling.

I have been involved in providing expert assistance or testimony regarding open access transmission filings in light of a changing utility environment and increased competition and in need determination proceedings.

Q. Have you worked for Florida Municipal Power Agency (FMPA) as a consultant before?

A. I have worked as a consultant to FMPA since FMPA's founding in 1978.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to discuss FMPA's recent request for proposals (RFP) related to purchase power, renewable energy, and demand-side management (DSM). I will also discuss FMPA's ongoing efforts to 1) utilize renewable generation; 2) potentially participate in future nuclear generating units; and 3) reduce CO_2 emissions.

Q. Are you sponsoring any sections of Exhibits to your testimony?

A. Yes. Exhibit No.___ [NPG-1] is a copy of my resume.

Q. Are you sponsoring any sections of Exhibit No. ___[FMPA-1], the Cane Island Unit 4 Need for Power Application?

A. Yes. I am sponsoring Sections 15.0, 16.0 (except for Section 16.3), 17.2, 18.0 (except for Section 18.2), 19.4 and Appendices A, B, and D to Exhibit No. ___(FMPA-1) , all of which were prepared under my direct supervision.

Q. Please summarize FMPA's RFP efforts.

A. In an effort to identify real projects to lower FMPA's cost and to improve FMPA's environmental performance, FMPA initiated four separate RFP's to evaluate purchase power alternatives to Cane Island 4, renewable energy resources (including a Solar RFP specifically for solar photovoltaic capacity and energy referred to as the solar RFP and discussed in the testimony of Mr. Tom Reedy), and demand-side management resources. Through the purchase power RFP, the renewables RFP, the Solar RFP, and the DSM RFP, FMPA sought to identify various potential alternatives to the addition of Cane Island 4. Although none of the four RFP's identified alternatives that could delay or replace Cane Island 4, they did result in projects which FMPA is pursuing. The status of the various RFP processes is summarized as follows:

- No purchase power alternatives to Cane Island 4 were submitted under the purchase power RFP;
- FMPA is continuing to negotiate potential purchase power agreements for capacity and energy from a new biomass and solar photovoltaic resources from both the renewables and Solar RFPs;

- FMPA is continuing to negotiate contracts with two DSM providers that could result in a reduction of the ARP's coincident peak demand by as much as 44 MW by 2016; and
- FMPA is also continuing to negotiate a contract with an Energy Service Company (ESCO).

Through the RFP processes described above and elaborated upon further in my testimony, FMPA has performed a thorough evaluation of reasonably available purchase power, renewable, and demand-side management alternatives to construction of Cane Island 4 in 2011.

Q. Does the FMPA currently use purchase power agreements to satisfy the ARP's generation requirements?

A. Yes. As discussed in the testimony of Mr. Tom Reedy, several purchase power agreements are in place with various entities including Progress Energy Florida (PEF), Florida Power & Light (FPL), Calpine, and Southern Power Company.

Q. Were any of these purchase power agreements a result of previous RFP processes?

A. Yes. The Calpine and Southern Power Company purchase power agreements were the result of previous RFP processes.

Q. Did FMPA make any efforts to extend existing purchase agreements that may expire during the evaluation period considered in this Application?

A. Yes. Mr. Tom Reedy discusses those efforts in his pre-filed testimony.

Q. Please describe FMPA's recent purchase power RFP.

A. The RFP served as an invitation for qualified companies to submit proposals for the supply of capacity and energy to meet a portion of the projected power requirements of the ARP beginning on January 1, 2011 and continuing over a period of at least 10 years. The RFP requested a minimum of 50 MW (up to a maximum of 300 MW) and required that the proposed capacity and energy be delivered to the PEF transmission system.

Q. How did FMPA notify potential bidders of the purchase power RFP?

A. The power supply RFP was distributed directly to 14 utilities and independent power producers (IPPs). Additionally, the RFP was posted on FMPA's website which allowed industry publications to pick it up for further distribution.

Q. What was the overall response to the RFP?

A. One of the requirements set forth in the power supply RFP was mandatory attendance at the pre-bid conference prior to submitting a response to the RFP. No potential bidders attended the pre-bid conference, nor did any entities submit notices of intent to bid, which were required (as stated in the RFP) to be submitted no later than July 3, 2007. The schedule set forth in the power supply RFP required that all bids in response to the RFP be submitted by August 17, 2007. No bidders responded to the power supply RFP, and therefore the power supply RFP process was terminated on November 5, 2007.

Q. Why do you believe FMPA did not receive any bids for the power supply RFP?

A. I do not have any direct knowledge of why individual entities decided not to bid. However, there are several potential reasons. First, Cane Island Unit 4 will be located at an existing site utilizing existing infrastructure. Second, FMPA's low cost of financing through the use of tax exempt municipal bonds results in lower cost power. Third, FMPA's ability to exercise an existing option to purchase the combustion turbine below the current market price makes FMPA's Cane Island 4 very economical. Finally, the current condition of the power market in the state of Florida is very tight.

Q. Does FMPA currently have any renewable capacity?

A. Yes. FMPA currently receives renewable energy from two sources. The first is as-available energy from a cogeneration plant fueled with bagasse owned by US Sugar Corporation. The second is landfill gas (LFG) from the Orange County Landfill that is burned as a supplemental fuel source in Stanton 1 and 2, coal fired units of which FMPA is a joint owner.

Q. Please discuss FMPA's Renewable RFP.

A. FMPA issued its Renewables RFP on June 29, 2007. The Renewables RFP served as an invitation for qualified companies to submit proposals for the supply of capacity and energy to meet a portion of the projected power requirements of the ARP beginning on January 1, 2011 or earlier and continuing

over a period of at least 5 years. The RFP requested a minimum of 1.0 MW with no upper limit on capacity and required that the proposed capacity and energy be delivered to either the FPL or PEF transmission systems.

Q. How did FMPA notify potential bidders of the Renewables RFP?

A. The Renewables RFP was distributed directly to 26 entities and notification of the RFP was posted in two industry publications. Additionally, the RFP was posted on FMPA's website which allowed industry publications to pick it up for further distribution.

Q. Did the Renewables RFP include a preference for the type of renewable energy resources proposed?

A. No, the RFP was open to any renewable technology. The Renewables RFP requested resources where the sole source of fuel used for the production of energy for sale to FMPA was from one or more of the following sources of renewable energy defined in 377.803(6) F.S.: hydrogen produced from sources other than fossil fuels; biomass; solar energy; geothermal energy; wind energy; ocean energy; hydroelectric power; waste heat from a commercial or industrial process; or any other technologies utilizing fuel/energy sources deemed by FMPA to be renewable in nature.

Q. How many bids did FMPA receive in response to the Renewables RFP?

A. FMPA received three bids. The three bids included a 58 MW summer rated biomass circulating fluidized bed (CFB) plant proposed that would burn waste wood and other materials including recycled pallets and paper derived fuel; 10 MW of roof-mounted solar photovoltaic (PV) systems; and a 1 MW to 3 MW centralized PV system.

Q. Please describe how these proposals were evaluated.

A. The first phase of the evaluation involved a screening of bids received with the minimum requirements as described in Section 20 of the Renewables RFP. This evaluation, which was completed on September 12, 2007, indicated that two (2) of the proposals had not clearly met certain of the minimum requirements. Questions were submitted to these two proposers to obtain additional information. At this point, FMPA decided to continue to consider all three of the proposals received.

A preliminary quantitative evaluation was completed for all three proposals on October 19, 2007. Based on the preliminary evaluation, FMPA short listed all three proposers and meetings were held with the proposers on October 31 through November 2, 2007. After the meetings a second set of questions were submitted to the proposers. Responses to the questions were received between November 14, 2007 and November 27, 2007. The centralized PV proposer

indicated that it could not support the original price offered and provided a higher priced verbal offer. After the second set of responses to questions was received, the evaluations were updated.

Q. What were the results of these evaluations?

A. The evaluations indicated that the levelized busbar costs for the three renewable alternatives were projected to be above FMPA's avoided cost. The biomass proposal was projected to be the lowest cost of the three proposals on a dollar per MWh basis.

Nevertheless, in spite of their higher costs, FMPA decided to continue negotiations with two of the proposers as part of its commitment to renewable resources. As of the time of the updated evaluation the bidder proposing the centralized PV system did not supply the required proposal security. As a result, no further meetings were held with this proposer.

Q. What were the results of these continued negotiations?

A. As a result of further negotiations, the rooftop PV proposer offered reduced pricing which was still above FMPA's avoided cost. FMPA is continuing negotiations with the rooftop PV proposer for an open-ended contract for up to 10 MW at FMPA's discretion. The proposer has agreed to continue discussions on this basis.

Negotiations with the biomass proposer have continued over the course of three additional meetings during March and April 2008. FMPA has explored different pricing arrangements over the course of the negotiations.

Q. Is FMPA moving forward with either of these proposals for renewable energy?

A. Yes. FMPA's ARP Executive Committee has approved continued negotiations for a power purchase from the biomass facility. Because the cost of biomass energy is higher than FMPA's avoided cost, before entering into a final contract with the proposer, FMPA will need to assess the cost penalty associated with the project. Furthermore, FMPA's ultimate commitment to utilizing biomass energy to serve its energy requirements will depend on whether biomass continues to be considered a renewable and carbon neutral energy source in Florida. FMPA will also need to examine the actions of other utilities in Florida in meeting their renewable targets to ensure that FMPA's rates remain cost competitive. The time frame for implementation of a biomass resource would depend on the time necessary to complete negotiations and obtain all required regulatory approvals and permits and approval of mutually agreeable commercial terms by FMPA.

The ARP Executive Committee also has approved continued negotiations for an open ended power purchase of up to 10 MW at FMPA's discretion from the roof-mounted PV systems bidder. While the cost of this alternative appears to

be higher on a $/MWh basis than the least cost solar PV bid discussed in the testimony of Mr. Tom Reedy, there may be special circumstances for which roof-mounted PV systems would be desirable. Again, FMPA will need to assess the cost penalty associated with the project and negotiate mutually agreeable commercial terms.

Q. Is FMPA considering other renewable opportunities?

A. Yes. FMPA is exploring several other renewable opportunities which include the following. FMPA is investigating the use of bio-fuels in several of its generating units. FMPA plans to conduct initial trials of the bio-fuel in Stock Island Units 1-3 which are combustion turbines that currently operate only on No. 2 oil. FMPA is working with a developer who is attempting to develop a large 15 MW LFG project. FMPA is working with Geoplasma, LLC, a developer which is attempting to develop a plasma arc project that would convert solid waste from the St. Lucie County landfill into syngas. FMPA has signed a letter of intent with Geoplasma, LLC, to explore the feasibility of the technology and development of the project. More detailed discussion of these additional renewable alternatives is presented in Section 16.4 of the Need for Power Application Exhibit ---(FMPA-1).

Q. Why did FMPA issue a DSM RFP?

A. As discussed in the testimony of Thomas Reedy, it is difficult for FMPA as a wholesale power provider to directly provide conservation and DSM programs

to retail customers. Through a DSM RFP, FMPA was looking for innovative ways in which private industry could provide conservation and DSM programs directly to ARP member retail customers.

Q. Please discuss FMPA's DSM RFP.

A. On July 27, 2007, FMPA issued its DSM RFP. The DSM RFP served as an invitation for qualified companies to submit proposals for DSM resources. DSM resources include any facility, program, or service implemented for retail customers that serves to permanently reduce or shift the time of consumption of electric energy and/or electric demand. The RFP requested a minimum contract term of one-year beginning no earlier than June 1, 2008. On-peak demand reductions must be at least 1,000 kW for third party proposers, and 500 kW for customer proposers.

Q. How did FMPA notify potential bidders of the DSM RFP?

A. The DSM RFP was distributed directly to thirty five (35) DSM providers and notification of the RFP was posted in one industry publication. Additionally, the RFP was posted on FMPA's website which allowed industry publications to pick it up for further distribution.

Q. How many bids did FMPA receive in response to the DSM RFP?

A. Four (4) proposals were received by the September 26, 2007 due date specified in the DSM RFP. Of the proposals received, three offered programs to reduce

FMPA's capacity or energy requirements – two using demand-response and the third through an energy services company or "ESCO" arrangement. The fourth proposal was an offer to provide computer software and equipment, which was not the type of proposal being sought by FMPA.

Q. Please describe the two demand response proposals and the ESCO proposal received in response to the DSM RFP.

A. The first demand response type proposal was projected to reduce the ARP's peak demand by 20 MW - 35 MW over a 5-year period. FMPA would pay a contractual rate for demand and energy reductions. The bidder would monitor FMPA's load from its 24 hour centralized control center and would curtail load when notified by FMPA. The bidder would bear the cost associated with monitoring and equipment installations. The bidder would guarantee MW reductions and would pay FMPA penalties for failure to deliver. Reductions would be measured against average kW usage during peak periods over the three highest usage days of the last 10 days.

The second demand response bidder's current offer is up to 44 MW of demand reduction over an 8-year period. The bidder would curtail load when notified by FMPA. The curtailment would be measured against the average of the participating facilities' single highest hourly demands for each of the four summer months of the previous year. The payment to the customer for the curtailment would be based on the average curtailment for all hours of the

events occurring during the month. The bidder would guarantee MW reductions and would pay FMPA penalties for failure to deliver. FMPA would be responsible for metering costs for each participating customer.

The proposed ESCO arrangement would set up an ESCO that would work directly with ARP members' customers such as schools, colleges, and large commercial and industrial customers to reduce energy usage by changing equipment, sequence of operation, or run times to reduce a customer's energy use. The customers would pay to get guaranteed energy reduction that would be guaranteed by the proposer.

Q. Please describe how these proposals were evaluated.

A. On October 26, 2007, lists of clarifying questions were submitted to the three qualified proposers described previously. Responses to the questions were received over the period November 3, 2007 through November 20, 2007. Based on these responses an evaluation of the DSM proposals was prepared on December 3, 2007. The evaluation compared pricing for each of the definitive proposals against the cost of conventional capacity.

Q. What were the results of these evaluations?

A. This evaluation concluded that both of the demand response proposals offered definitive proposals for demand response programs that were projected to reduce FMPA's demand. The pricing for one of the demand response proposals was

clearly lower than the other and could potentially reduce FMPA's demand related costs compared to supply-side alternatives. The third proposal, the ESCO, did not provide a specific energy reduction or pricing after clarifying questions had been asked except to project that participating customers could reduce their energy consumption by 15 percent to 20 percent. None of the proposals offered definitive energy efficiency or conservation programs.

Based on the initial evaluation of the DSM proposals, FMPA decided to meet with the three qualified DSM proposers to further clarify DSM programs that could reduce FMPA's costs and help meet FMPA's goals to reduce greenhouse gas emissions. FMPA met with all of the proposers in January 2008 and has followed up with all of them with further meetings and/or phone calls. FMPA continued to negotiate agreements with all three proposers.

Q. What were the results of these continued negotiations?

A. Following initial negotiations between FMPA and the DSM proposers, both of the demand response proposers were approved by the ARP Executive Committee for further negotiations. FMPA is continuing negotiations with both demand response proposers. In addition, FMPA is continuing discussions with the ESCO proposer relating to their energy efficiency/conservation type proposal.

Q. Is FMPA moving forward with either of the demand response proposals?

A. Yes. Based on responses to the DSM RFP and subsequent discussions with the demand response proposers, FMPA is examining the possibility of implementing a demand response program that could potentially reduce the ARP coincident peak demand by up to approximately 44 MW by 2016, with the following assumed implementation schedule based on the information provided by one of the proposers:

- 15 MW in 2009
- 7 MW in 2010 (22 MW cumulative)
- 4 MW in 2011 (26 MW cumulative)
- 4 MW in 2012 (30 MW cumulative)
- 4 MW in 2013 (34 MW cumulative)
- 4 MW in 2014 (38 MW cumulative)
- 4 MW in 2015 (42 MW cumulative)
- 2 MW in 2016 (44 MW cumulative)

Q. Is FMPA pursuing any other conservation and DSM initiatives?

A. Yes. These initiatives are discussed in the prefiled testimony of Thomas Reedy, and Section 17.3 of Exhibit No. __ (FMPA-1).

Q. Has FMPA undertaken any actions that have reduced the ARP's carbon footprint?

A. Yes. Historically, FMPA has sought to improve the efficiency of its generating fleet, which has had the added benefit of reducing carbon intensity (quantity of

CO_2 per unit of energy produced). These activities have involved installation of new efficient natural gas combined cycle generating units which allowed the retirement and displacement of older inefficient oil and gas units. In addition, these efficient natural gas combined cycle generating units also allowed for the replacement of higher emitting purchase power contracts. These efficient natural gas combined cycle units include the existing Cane Island Units 2 and 3, Stanton A, as well as the Treasure Coast Energy Center scheduled for commercial operation in May of 2008. In addition to installing efficient combined cycle generation units, FMPA has also entered into unit specific purchase power arrangements which provide power from efficient natural gas fueled combined cycle resources. Examples of these purchases include the portion of Stanton A that is purchased from Southern Company and Calpine – Osprey. When simple cycle capacity was required, FMPA constructed a LM6000 combustion turbine at Stock Island which is the most efficient combustion turbine of its size. FMPA also recently entered into a purchase power contract from Southern Company's Oleander site which utilizes the efficient General Electric 7FA combustion turbines.

Other historical carbon reduction activities include the U.S. Sugar and Stanton Landfill gas renewable projects discussed earlier as well as existing conservation and DSM programs discussed in the prefiled testimony of Thomas Reedy.

Q. Is FMPA pursuing any additional activities that will further reduce CO_2 emissions?

A. Yes. Cane Island 4 will allow further retirement and displacement of inefficient generation, which will reduce FMPA's total CO_2 emissions. Upgrades to the Crystal River 3 and St. Lucie 2 nuclear units for which ARP or its members are joint owners will increase the capacity of these units which emit zero CO_2. This increase in ARP's nuclear capacity will further reduce the ARP's total CO_2 emissions. In the longer term, FMPA is pursuing participation in the Progress Energy Florida's Levy County units 1 and 2 and FPL's Turkey Point units 6 and 7 nuclear units. Successful implementation of the potential biomass and photovoltaic projects discussed earlier also would reduce FMPA's CO_2 emissions. Continued existing and future new conservation and DSM programs will also reduce FMPA's CO_2 emissions. Details of FMPA's carbon reduction activities are presented in Section 18.0 of the Need for Power Application. Exhibit No.____ (FMPA-1)

Q. How do FMPA's projected CO_2 emissions compare to the 2017 goal in Executive Order 07-127?

A. FMPA's preliminary analyses indicate that the least cost expansion plan with Cane Island Unit 4 would enable FMPA to achieve the 2017 CO_2 emission target level in Executive Order 07-127.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF BRADLEY E. KUSHNER

ON BEHALF OF

FLORIDA MUNICIPAL POWER AGENCY

DOCKET NO. _____

MAY 7, 2008

Q. Please state your name and business address.

A. My name is Bradley E. Kushner. My business mailing address is 11401 Lamar Avenue, Overland Park, Kansas 66211.

Q. By whom are you employed and in what capacity?

A. I am employed by Black & Veatch Corporation where I am currently a Manager.

Q. Please describe your responsibilities in that position.

A. I am responsible for the management of various projects for utility and non-utility clients. These projects include production cost modeling associated with power system expansion planning, feasibility studies, and demand-side management (DSM) evaluations. I also have involvement in the issuance and evaluation of requests for proposals (RFPs).

Q. Please describe Black & Veatch.

A. Black & Veatch Corporation has provided comprehensive engineering, consulting, and management services to utility, industrial, and governmental

clients since 1915. Black & Veatch specializes in engineering, consulting, and construction associated with utility services including electric, gas, water, wastewater, telecommunications, and waste disposal. Service engagements consist principally of investigations and reports, design and construction, feasibility analyses, rate and financial reports, appraisals, reports on operations, management studies, and general consulting services. Present engagements include work throughout the United States and numerous foreign countries.

Q. Please state your educational background and professional experience.

A. I received my Bachelors of Science in Mechanical Engineering from the University of Missouri – Columbia in 2000. I have more than 8 years of experience in the engineering and consulting industry. I have experience in the development of integrated resource plans, ten-year-site plans, demand-side management plans, and other capacity planning studies for clients throughout the United States. Utilities in Florida for which I have worked include Florida Municipal Power Agency (FMPA), JEA, Kissimmee Utility Authority, Orlando Utilities Commission, Lakeland Electric, Reedy Creek Improvement District, Tampa Electric Company (TECO), and the City of Tallahassee. I have performed production cost modeling and economic analysis, and otherwise participated in three previous Need for Power Applications that have been filed on behalf of Florida utilities and approved by the Florida Public Service Commission (FPSC). I have also testified before the FPSC in previous Need for Power filings.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to discuss the fuel and emissions allowance price forecasts and supply-side alternatives used in the economic analysis of Cane Island 4. I will also discuss the methodology utilized in the analyses, as well as the results of the economic evaluations that were performed for numerous scenarios and sensitivities.

Q. Have you prepared any exhibits to your testimony?

A. Yes. Exhibit No. __[BEK-1] is a copy of my resume. Exhibit No.__ [BEK-2] presents the Reference Case fuel price projections. Exhibit No.__ [BEK-3] presents the High Price Case fuel price projections. Exhibit No.__ [BEK-4] presents the Low Price Case fuel price projections. Exhibit__[BEK-5] is a series of tables presenting the results of the economic evaluation of Cane Island 4.

Q. Are you sponsoring any sections of Exhibit No. __ [FMPA-1], the FMPA Cane Island Power Plant 4 Need for Power Application?

A. Yes. I am sponsoring Sections 7.0, 14.0, 19.0 (with the exception of 19.4), 20.0, and 21.0, all of which were prepared by me or under my direct supervision.

Q. Please describe the basis for the fuel price projections used in the Cane Island 4 Need for Power Application, Exhibit No. __ [FMPA-1].

A. The fuel price projections for natural gas, fuel oil, and coal used for the economic evaluations presented in Exhibit No. __ [FMPA-1] were based on

those presented in the US Energy Information Administration's (EIA) Annual Energy Outlook 2007 (AEO2007).

The AEO2007 presents projections of energy supply, demand, and prices through the year 2030. The projections presented within the AEO2007 are based on results from the EIA's National Energy Modeling System (NEMS). NEMS is a computer-based, energy-economy modeling system of US energy markets and projects the production, imports, conversion, consumption, and prices of energy, subject to a variety of assumptions related to macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, technology characteristics, and demographics.

AEO2007 includes the Reference Case, as well as numerous other cases. For purposes of the economic evaluations presented in Exhibit No. __[FMPA-1], the AEO2007 High Price Case and Low Price Case were considered in addition to the Reference Case.

Q. How are state and federal legislation and regulations reflected in AEO2007?

A. Analyses developed by the EIA are required to be policy neutral. Therefore, the projections in the AEO2007 are based on federal and state laws and regulations in effect on or before October 31, 2006 (with few exceptions). As stated in the AEO2007, the potential impacts of pending or proposed legislation, regulations, and standards – or of sections of legislation that have been enacted, but that

require implementing regulations or appropriation of funds that are not provided or specified in the legislation itself – are not reflected in the projections.

Q. Were any steps taken to consider the effects of the potential for future regulation related to emissions of carbon dioxide (CO_2)?

A. Yes. As I will discuss later in my testimony, several different cases reflecting regulation of CO_2 were considered. The CO_2 and corresponding fuel price projections used in these evaluations were based on projections from both the EIA and the US Environmental Protection Agency (EPA) and considered two separate proposals to the 110th US Congress to regulate CO_2 emissions.

Q. Does AEO2007 provide projections of fuel prices for fuel delivered to the Florida region?

A. Yes. The AEO2007 Reference Case includes fuel price projections for delivered fuel to numerous geographic areas throughout the US. The natural gas and fuel oil price projections used in the economic evaluations presented in Exhibit No. __ [FMPA-1] were based on AEO2007 price projections for natural gas and fuel oil delivered to the Florida Reliability Coordinating Council (FRCC). Coal price projections were based on the AEO2007 price projections for coal delivered to the Georgia/Florida region.

The Reference Case fuel price projections considered throughout Exhibit No. __ [FMPA-1] reflect the region-specific fuel price projections for use in the electric power sector.

Q. Were any adjustment made to the AEO2007 region-specific Reference Case fuel price projections?

A. Yes. The AEO2007 fuel price projections were developed in real 2005 dollars. For purposes of the economic evaluations presented in Exhibit No. __[FMPA-1], these projections were converted to nominal dollars using the general inflation rate of 2.3 percent discussed in the testimony of Mr. Myron Rollins.

Q. How were forecasts of nuclear fuel price projections developed?

A. Projections of nuclear fuel prices were based on nuclear fuel price projections used in previous analyses we performed for FMPA. Those costs were adjusted to reflect the general inflation rate of 2.3 percent discussed in the testimony of Mr. Myron Rollins.

Q. What were the resulting Reference Case fuel price projections used throughout Exhibit No. __ [FMPA-1].

A. The Reference Case fuel price projections used throughout the economic evaluations are presented in Exhibit No. __ [BEK-2].

Q. Were solid fuel alternatives among those considered as viable generation expansion options?

A. Biomass generation was the only solid fuel alternative considered for this analysis. A discussion of the biomass generation considered in the analysis is provided in the testimony of Mr. Nicholas Guarriello. Due to permitting and regulatory uncertainties, coal-fired generating alternatives were not considered

for Cane Island 4. Nuclear units were only considered in terms of the potential identified joint ownership opportunities with Florida Power & Light and Progress Energy Florida.

Q. Did the economic analyses consider the costs associated with emission allowances?

A. Yes. AEO2007 considers the potential impact of both the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR). Subsequent to completion of the AEO2007, the US Court of Appeals for the District of Columbia Circuit vacated the CAMR in a decision issued February 8, 2008. Because Exhibit No. __ [FMPA-1] does not consider the addition of any coal fired generating units as future resource alternatives, the impact of the current uncertainty associated with regulation of mercury emissions is insignificant in the analyses presented throughout this Application. Costs associated with emissions of mercury are not considered in this Application. The economic analysis uses the forecast allowance prices for emissions of SO_2 and NO_x from the AEO2007 Reference Case fuel forecast, as well as the High Price and Low Price fuel forecasts.

Emission allowance price forecasts for SO_2, NO_x, and CO_2 were also developed for hypothetical sensitivity evaluations in which emissions of CO_2 would be regulated in the US.

Q. How were the emissions prices for CO_2 derived, given that CO_2 emissions are not currently regulated?

A. Although CO_2 emissions are not currently regulated, the EIA developed analyses of two of the major pieces of proposed legislation. The two proposed bills analyzed were *S. 280, the Climate Stewardship and Innovation Act of 2007* and *S.1766, the Low Carbon Economy Act of 2007.* The CO_2 emission allowance price projections presented in the EIA's analysis of S.280 were generally higher than for S. 1766.

In addition, the EPA recently developed CO_2 cost estimates for *S. 2191, America's Climate Security Act of 2007.* The EPA's cost estimates are higher than those developed by EIA in their analysis of S.280. For that reason, the EPA estimates were utilized in the high CO_2 sensitivity analysis presented in Section 20.0 of the Need for Power Application, Exhibit No. __ [FMPA-1].

Q. How were the detailed economic analyses conducted?

A. The optimal generation expansion plan evaluations were performed using STRATEGIST, a computer software system developed by Ventyx (previously NewEnergy Associates, LLC.). STRATEGIST is the updated version of PROSCREEN.

Q. How does STRATEGIST determine the most optimal generation plan?

A. STRATEGIST includes an automatic expansion planning module which determines the optimal balanced demand and supply plan for a utility system under a prescribed set of constraints and assumptions. It evaluates all combinations of generating unit alternatives and purchase power options in conjunction with existing capacity resources to satisfy forecast capacity requirements while maintaining user-defined reliability criteria. STRATEGIST simulates the operation of a utility system to determine the cost and reliability effects of adding resources to the system or modifying the load through demand-side management (DSM) programs. The expansion plan that results in the lowest cumulative present worth of costs (CPWC) is the optimal generation plan.

Q. How did STRATEGIST simulate utility system operation to arrive at the optimal generation plan for FMPA?

A. The simulation of the utility system operation is accomplished using dynamic programming, a mathematical technique useful for making a sequence of interrelated decisions for determining the combination of decisions that optimizes the desired outcome (lowest CPWC in this case). In this Application, all expansion plans were analyzed over a 20 year period from 2008 through 2027.

Q. What supply-side alternatives were included in the detailed economic analysis?

A. The detailed economic analysis considered the following generating unit alternatives:

- GE LM6000 Simple Cycle
- GE LMS100 Simple Cycle
- GE 7EA Simple Cycle
- GE 7FA Simple Cycle
- GE 1x1 7FA Combined Cycle

In addition, the economic impacts of renewable (biomass and photovoltaic resources) and DSM proposals available to FMPA were evaluated. Further description of these proposals is provided in the testimony of Mr. Nicholas Guarriello and Mr. Thomas Reedy.

Four distinct scenarios were developed. Scenario 1 considered the addition of only combustion turbine and combined cycle generating units. Scenario 2 considered the addition of new renewable energy resources supplemented by combustion turbine and combined cycle generating unit alternatives when additional capacity was needed. Scenario 3 considered the addition of new DSM resources supplemented by combustion turbine and combined cycle generating unit alternatives when additional capacity was needed. Scenario 4 considered the addition of both the new renewable energy resources and the new DSM resources again supplemented by combustion turbine and combined cycle generating alternatives when additional capacity was needed.

Q. How was the least-cost capacity expansion plan identified for FMPA?

A. STRATEGIST was used to identify the optimal, or least cost, expansion plan based on CPWC. The CPWC which are presented in Exhibit No.__[BEK-5] include production costs consisting of fuel, purchase power, variable O&M, and emission allowance costs and fixed costs consisting of fixed O&M, fixed charges on new generating units, DSM charges, and incremental natural gas transportation charges. The CPWC are presented in 2008 dollars over the 2008 through 2027 evaluation period using the 5.0 percent present worth discount rate discussed in the testimony of Mr. Myron Rollins.

Q. What were the results of the economic analysis for FMPA?

A. Analysis of the CPWC associated with each of the cases analyzed indicates that expansion plans including the addition of Cane Island 4 in May 2011 are the most cost-effective expansion plans for all cases considered.

Q. Did you conduct any sensitivity analyses?

A. Yes.

Q. Please provide an overview of this sensitivity analysis.

A. Sensitivity analyses were performed on the Scenario 1 cases to supplement the base case economic analysis and to demonstrate the robustness of the capacity expansion plans. The sensitivity analyses measure the impact of varying key

assumptions used in the base case economic analysis, as well as the impacts of considerations not included in the base case.

The general methodology used in the sensitivity analyses was similar to the methodology used in the base case analysis described previously in my testimony. STRATEGIST was used to determine the optimal capacity expansion plan for all cases considered under different sensitivity cases.

Q. What sensitivity analyses were conducted?

A. Sensitivity analyses were developed to evaluate the impact of:

1. High fuel prices
2. Low fuel prices
3. High loads
4. Low loads
5. High capital costs
6. Regulated CO_2
7. High fuel prices with regulated CO_2
8. High CO_2 costs

Q. What were the results of these sensitivity analyses?

A. Exhibit No.____[BEK-5] presents a summary of the results of all of the economic evaluations, including each of the sensitivity analyses performed. As shown in Exhibit No.____ [BEK-5], the addition of Cane Island 4 in May 2011

represents the least-cost capacity expansion plan under all sensitivity evaluations.

The results of the sensitivity analyses, coupled with the results of the base case analysis, demonstrate that the capacity expansion plan including the addition of Cane Island 4 in May 2011 is a robust plan, and is sufficiently flexible to overcome variations and deviations from the base case assumptions.

Q. Is Cane Island 4 the most cost-effective alternative available to FMPA?

A. Yes. Cane Island 4 is the most cost-effective alternative available to FMPA. In Scenario 1 (conventional resources), the addition of Cane Island 4 in May 2011 will result in CPWC savings of approximately $36 million when compared to the least cost plan with Cane Island 4 not installed in May 2011. The amount of CPWC savings for the sensitivity evaluations ranges from approximately $22 million to approximately $81 million.

In Scenario 2 (conventional and renewable resources), the addition of Cane Island 4 in May 2011 will result in CPWC savings of approximately $34 million when compared to the least cost plan with Cane Island 4 not installed in May 2011. In Scenario 3 (conventional and DSM), the addition of Cane Island 4 in May 2011 will result in CPWC savings of approximately $53 million when compared to the least cost plan with Cane Island 4 not installed in May 2011. In Scenario 4 (conventional, renewable, and DSM), the addition of Cane Island 4

in May 2011 will result in CPWC savings of approximately $38 million when compared to the least cost plan with Cane Island 4 not installed in May 2011.

Regulated CO_2 sensitivity evaluations were performed for every scenario considered in Exhibit No. __ [FMPA-1]. For all scenarios considered, the addition of Cane Island 4 in May 2011 represents the most cost-effective alternative available to FMPA.

Q. Will Cane Island 4 provide adequate electricity at a reasonable cost to FMPA Members?

A. Yes. The expansion plan with Cane Island 4 in 2011 will help to meet each Member's electric generation needs at the lowest cost of all the alternatives evaluated.

Q. Have renewable energy sources and technologies, as well as conservation measures been evaluated to the extent that they are reasonably available to FMPA in the economic evaluations?

A. Yes. As discussed in the testimony of Mr. Nicholas Guarriello and Mr. Thomas Reedy, FMPA implemented RFP processes to identify available renewable energy sources and technologies as well as conservation measures. The results of the economic evaluations demonstrate that Cane Island 4 is the most cost effective alternative available to FMPA including consideration of reasonably available renewable energy sources and technologies as well as conservation measures.

Q. What are the consequences to FMPA of delaying Cane Island Unit 4?

A. As demonstrated by the economic evaluations presented in the Application, the results of which are summarized in Exhibit No.__ [BEK-5], the addition of Cane Island Unit 4 in 2011 represents the most cost-effective addition to satisfy FMPA's forecast capacity requirements to reliably serve the ARP members. The consequences of delaying the commercial operation of Cane Island 4 are significant from an economic and reliability standpoint for FMPA.

If the commercial operation of Cane Island 4 is delayed, FMPA would be required to replace the capacity and energy that would otherwise be provided by a new, efficient combined cycle generating unit. The economic consequence of delaying the commercial operation of Cane Island Unit 4 for 2 years (from May 2011 until May 2013) is approximately $35.7 million in CPWC, compared to the next most cost effective expansion plan that meets FMPA's 2011 capacity requirements with simple cycle combustion turbines.

FMPA is projected to require a significant amount of capacity in the summer of 2011 to maintain its reserve margin requirements. If Cane Island Unit 4 is delayed and no additional generating capacity is installed to meet FMPA's forecast capacity requirements by 2011, FMPA's summer reserve margin will fall to approximately -1.3 percent (or 286 MW less than the 18 percent summer reserve criterion) in 2011. The projected capacity deficit in the summer of 2011 is equivalent to nearly all of the capacity that will be provided by Cane Island

Unit 4. With a projected negative reserve margin in 2011, FMPA would not be able to serve firm load with resources under FMPA's control. This would increase the probability that FMPA will not be able to provide FMPA's members with capacity to serve their retail customers and will expose FMPA to potentially high purchase power costs.

Q. Does this conclude your testimony?

A. Yes.

CHAIRMAN CARTER: Staff.

MS. FLEMING: As staff mentioned previously, we would note that there are proposed stipulations on all issues. The proposed stipulations start on Page 4 of the prehearing order. If the Commissioners would like a brief summary as to what those proposed stipulations entail, we would be more than happy to do so.

CHAIRMAN CARTER: Commissioners, any questions on the proposed stipulations?

COMMISSIONER EDGAR: No questions.

CHAIRMAN CARTER: Okay. Well, then without objection, show it done.

MS. FLEMING: With that, Commissioners, staff would recommend that the Commission make a bench decision with respect to the proposed stipulations. If the Commissioners are inclined to do so, then staff would recommend that the Commissioners -- recommend that the issues identified in the prehearing order for the proposed stipulations be approved.

CHAIRMAN CARTER: Thank you.

Commissioners, before we go to that matter, if there are any questions, or concerns, or statements?

Commissioner Edgar, you're recognized.

COMMISSIONER EDGAR: Mr. Chairman, I'm comfortable with the stipulated issues and the work that our staff has done with the parties to present this item before us, and so

whenever you are ready, I will be prepared to make a motion.

CHAIRMAN CARTER: Thank you.

Commissioner Argenziano.

COMMISSIONER ARGENZIANO: I'm right there with Commissioner Edgar. I would like to thank staff for the hard work, because it has all been stipulated and I agree with the stipulations.

CHAIRMAN CARTER: Thank you, Commissioner.

Commissioner Edgar, you're recognized for a motion.

COMMISSIONER EDGAR: Thank you. Then at this time I would move approval of stipulated Issues 1 through 8 as identified in the prehearing order.

CHAIRMAN CARTER: Commissioner Argenziano, the second?

COMMISSIONER ARGENZIANO: Second. I'm sorry.

CHAIRMAN CARTER: It has been moved and properly seconded. Commissioners, any debate? Any further discussion?

Hearing none, all those in favor let it be known by the sign of aye?

(Simultaneous affirmative vote.)

CHAIRMAN CARTER: All those opposed, like sign?

Staff, you're recognized for any concluding matters or procedures.

MS. FLEMING: Thank you, Chairman.

Since the Commissioners have voted to approve the

stipulations identified in the prehearing order, post-hearing filings are not necessary. So with that, we will note that the order will be issued by August 25th.

CHAIRMAN CARTER: Thank you kindly. Commissioners, any further comments before we adjourn?

COMMISSIONER ARGENZIANO: No.

CHAIRMAN CARTER: Thank you so kindly. We are adjourned.

(The hearing concluded at 9:38 a.m.)

STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

COUNTY OF LEON)

I, JANE FAUROT, RPR, Chief, Hearing Reporter Services Section, FPSC Division of Commission Clerk, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 5th day of August, 2008.

JANE FAUROT, RPR
Official FPSC Hearings Reporter
(850) 413-6732

Comprehensive Exhibit List for Entry into Hearing Record

Hearing I.D.#	Witness	I.D. # As Filed	Exhibit Description	Entered
Staff				
1		Exhibit List - 1	Comprehensive Exhibit List	
2		Staff's Composite Exhibits – 2 stipulated	**Interrogatories** 1) FMPA's Responses to Staff's First Set of Interrogatories (Nos. 1-8) *[Bates Stamp Nos. 00000001 – 00000013]* 2) FMPA's Responses to Staff's Second Set of Interrogatories (Nos. 9-20) *[Bates Stamp Nos. 00000014 – 00000028]* 3) FMPA's Responses to Staff's Third Set of Interrogatories (Nos. 21-29)*[Bates Stamp Nos. 00000029 – 00000036]* 4) FMPA's Responses to Staff's Fourth Set of Interrogatories (Nos. 30-31, 34-43, 45-46, 49-50) *[Bates Stamp Nos. 00000037 – 00000137]* 5) FMPA's Responses to Staff's Fifth Set of Interrogatories (Nos. 51-53) *[Bates Stamp Nos. 00000138 – 00000144]*	

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080253-EM **EXHIBIT** 1
COMPANY FL PSC Staff
WITNESS Exhibit List 1
DATE 08-04-08

Comprehensive Exhibit List for Entry into Hearing Record				
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**	**Entered**
			6) FMPA's Responses to Staff's Sixth Set of Interrogatories (No. 54) *[Bates Stamp Nos. 00000145 – 00000148]* **Request for Production of Documents** 7) FMPA's Response to Staff's First Request for Production of Documents (Nos. 1-3) *[Bates Stamp Nos. 00000149 – 00000406]* 8) FMPA's Response to Staff's Third Request for Production of Documents (Nos. 5-6, 8-10) *[Bates Stamp Nos. 00000407 – 00000551]* 9) FMPA's Response to Staff's Fifth Request for Production of Documents (No. 16) *[Bates Stamp Nos. 00000552 – 00000556]* **Additional Items** 10) FMPA-1E, which consists of an errata sheet and revised tables for the Need for Power Application previously filed as FMPA-1 *[Bates Stamp Nos. 00000557 – 00000561]*	

Comprehensive Exhibit List for Entry into Hearing Record

Hearing I.D. #	Witness	I.D. # As Filed	Exhibit Description	Entered
			11) Errata sheet for the Pre-filed Direct Testimony of Thomas E. Reedy *[Bates Stamp Nos. 00000562 – 00000564]* 12) Errata sheet for the Pre-filed Direct Testimony of Myron R. Rollins *[Bates Stamp Nos. 00000565 – 00000566]* 13) Errata sheet for the Pre-filed Direct Testimony of Bradley E. Kushner *[Bates Stamp Nos. 00000567 – 00000568]*	
Florida Municipal Power Agency (Direct)				
3	All witnesses	FMPA-1	Need for Power Application	
4	Roger A. Fontes	RAF-1	Map of ARP Members	
5	Thomas E. Reedy	TER-1	ARP's Existing and Approved/Planned Resource Capacity	
6	Thomas E. Reedy	TER-2	Resumé of Thomas E. Reedy	
7	Jonathan P. Nunes	JPN-1	Resumé of Jonathan P. Nunes	
8	Myron R. Rollins	MRR-1	Resumé of Myron R. Rollins	

Comprehensive Exhibit List for Entry into Hearing Record				
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**	**Entered**
9	Myron R. Rollins	MRR-2	Cane Island 4 In-Service Capital Cost Estimate	
10	Myron R. Rollins	MRR-3	Estimated 1x1 F Class Combined Cycle Performance	
11	Jason L. Wolfe	JLW-1	Resumé of Jason L. Wolfe	
12	Nicholas P. Guarriello	NPG-1	Resumé of Nicholas P. Guarriello	
13	Bradley E. Kushner	BEK-1	Resumé of Bradley E. Kushner	
14	Bradley E. Kushner	BEK-2	Reference Case Fuel Price Projections	
15	Bradley E. Kushner	BEK-3	High Case Fuel Price Projections	
16	Bradley E. Kushner	BEK-4	Low Case Fuel Price Projections	
17	Bradley E. Kushner	BEK-5	Economic Analysis Summaries	

HEARING EXHIBITS				
Exhibit Number	**Witness**	**Party**	**Description**	**Moved In/Due Date of Late Filed**
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				

HEARING EXHIBITS				
Exhibit Number	**Witness**	**Party**	**Description**	**Moved In/Due Date of Late Filed**
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080253-EI **EXHIBIT** 2
COMPANY FL PSC Staff
WITNESS Staff's Composite Exhibit's - 2 Stipulated
DATE 08-04-08

EXHIBIT NO. _____

DOCKET NO: 080253-EM

WITNESS: VARIOUS

PARTY: FLORIDA MUNICIPAL POWER AGENCY

DESCRIPTION: STAFF'S STIPULATED COMPOSITE EXHIBITS - 2

DOCUMENTS:

Interrogatories

1) FMPA's Responses to Staff's First Set of Interrogatories (Nos. 1-8) *[Bates Stamp Nos. 00000001 – 00000013]*

2) FMPA's Responses to Staff's Second Set of Interrogatories (Nos. 9-20) *[Bates Stamp Nos. 00000014 – 00000028]*

3) FMPA's Responses to Staff's Third Set of Interrogatories (Nos. 21-29) *[Bates Stamp Nos. 00000029 – 00000036]*

4) FMPA's Responses to Staff's Fourth Set of Interrogatories (Nos. 30-31, 34-43, 45-46, 49-50) *[Bates Stamp Nos. 00000037 – 00000137]*

5) FMPA's Responses to Staff's Fifth Set of Interrogatories (Nos. 51-53) *[Bates Stamp Nos. 00000138 – 00000144]*

6) FMPA's Responses to Staff's Sixth Set of Interrogatories (No. 54) *[Bates Stamp Nos. 00000145 – 00000148]*

Request for Production of Documents

7) FMPA's Response to Staff's First Request for Production of Documents (Nos. 1-3) *[Bates Stamp Nos. 00000149 – 00000406]*

8) FMPA's Response to Staff's Third Request for Production of Documents (Nos. 5-6, 8-10) *[Bates Stamp Nos. 00000407 – 00000551]*

9) FMPA's Response to Staff's Fifth Request for Production of Documents (No. 16) *[Bates Stamp Nos. 00000552 – 00000556]*

Additional Items

10) FMPA-1E, which consists of an errata sheet and revised tables for the Need for Power Application previously filed as FMPA-1 *[Bates Stamp Nos. 00000557 – 00000561]*

11) Errata sheet for the Pre-filed Direct Testimony of Thomas E. Reedy *[Bates Stamp Nos. 00000562 – 00000564]*

12) Errata sheet for the Pre-filed Direct Testimony of Myron R. Rollins *[Bates Stamp Nos. 00000565 – 00000566]*

13) Errata sheet for the Pre-filed Direct Testimony of Bradley E. Kushner *[Bates Stamp Nos. 00000567 – 00000568]*

PROFFERED BY: STAFF

1

FMPA's Responses to Staff's First Set of Interrogatories (Nos. 1-8)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition to determine need for Cane Island Power Park Unit 4 electrical power plant in Osceola County, by Florida Municipal Power Agency.	DOCKET NO. 080253-EM DATED: JUNE 23, 2008

FLORIDA MUNICIPAL POWER AGENCY RESPONSES TO STAFF'S FIRST SET OF INTERROGATORIES (NOS. 1 - 8)

Florida Municipal Power Agency (FMPA) pursuant to Rule 28-106.206, Florida Administrative Code (F.A.C.), and Rule 1.340, Florida Rules of Civil Procedure, hereby responds to Staffs First Set of Interrogatories (Nos. 1-8).

INTERROGATORIES

1. **For Table 7-17 "Projected CO2 Emission Allowance Prices EIA S.280 Core Case" on page 7-45 of the Need for Power Application, please provide the following information:**
   - **a. Please explain or describe the term "S.280 Core";**
   - **b. Please identify or describe the assumptions forming the basis of the "S.280 Core" case; and**
   - **c. Please explain or describe why "S.280 Core" was designated as the core case in this analysis.**

Response:

a. The EIA defines the "S.280 Core" case as the primary policy case, and uses the S.280 Core case as the basis for numerous sensitivity cases that reflect changes to various areas of uncertainty.

b. The EIA developed its S.280 Care case based on the following assumptions:

- The discount rate for allowance banking is 8.0 percent.
- 30 percent of allowances would be auctioned in 2012, and the percent of allowances auctioned would grow linearly to 90 percent by 2030.

- Commercial sector entities would be exempt from regulation under S.280.
- Half of the incremental costs of energy-efficient appliances in the residential and commercial sectors would be subsidized through rebates from the Climate Change Credit Corporation, which S.280 contemplates establishing as a nonprofit corporation.
- Up to 30 percent of allowance submissions may be satisfied through offsets.
- Non-CO_2 greenhouse gas emissions growth is based on data received from the US Environmental Protection Agency (EPA).
- Non-CO2 greenhouse gas emissions abatement, biogenic carbon sequestration, and international offset supply are based on data received from the US EPA.

c. The S.280 Core case was selected as the basis for two of the three regulated CO_2 sensitivity cases that were evaluated in the Cane Island 4 Need for Power Application because the projected impacts on fuel and emissions allowance prices associated with the S.280 Core case fall within the boundaries set by the other 11 policy cases considered by the EIA in their analysis of S.280. Taken in combination with the S.280 Core case being considered by EIA as representative of the primary policy case, the S.280 Core case was considered an appropriate case to be used as the basis for consideration of the potential impact of future regulations of CO_2.

2. **With regard to the proposed Cane Island 4 generating unit, does FMPA plan to install, now or in the future, any auxiliary system/equipment/technology such as FGD (flue gas desulfurization) and Selective Catalytic Reduction (SCR) to ensure compliance with CAIR, CAMR, or other relevant air emission rules?**

Response:

Yes. FMPA plans to install SCR and dry low-NO_x combustion technology to minimize emissions of NO_x, which will be regulated under CAIR. As a natural gas combined cycle generating unit, the proposed Cane Island 4 generating unit will minimize emissions of SO_2 (which will be regulated under CAIR), as well as particulate matter. Due to the very low sulfur content of natural gas, additional sulfur dioxide emissions control equipment, such as flue gas desulfurization, is not necessary for Cane Island 4. Emissions of carbon monoxide and volatile organic compounds will also be within permitted limits. Emissions of mercury will be negligible and no additional mercury control technologies will be necessary for the proposed Cane Island 4.

3. **If the response to Interrogatory No. 2 is yes, please respond to the following questions:**
   a. **Please identify or describe the related capital and O&M costs associated with the implementation of the items discussed in Interrogatory No. 2; and**
   b. **Please explain or describe whether the costs identified in Interrogatory No. 2 have been included in Table 20-2 "CPWC Summaries for Scenario 1" on page 20-7, of Section 20 of the Need for Power Application.**

Response:

a. The capital and O&M costs associated with the emissions control technologies described in response to Staff's Interrogatory No. 2 are included in the total capital and O&M cost estimates for the proposed Cane Island 4 generating unit presented on pages 9-12 and 9-13 of the Cane Island 4 Need for Power Application but are not separately identified in the Application.

b. The capital and O&M costs associated with the emissions control technologies described in response to Staff's Interrogatory No. 2 are included in the CPWC results presented in Table 20-2 of the Cane Island 4 Need for Power Application.

4. In Section 9.1.6 Air Quality Control, on page 9-3 of the Need for Power Application, it states that SCR will be installed to further reduce NOx emissions. With regard to the proposed installation of SCR, please provide the following information:

a. Please explain or describe when FMPA will install SCR;

b. Please identify or describe the projected capital costs associated with the proposed SCR installation;

c. Please explain or describe whether FMPA has included the costs of SCR installation within its cost estimates for Cane Island 4; and

d. If the response to Interrogatory No. 4c is yes, please identify or describe where the costs associated with the installation of the SCR can found be in FMPA's need filing.

Response:

a. The proposed Cane Island 4 generating unit will include SCR during the construction phase of the project, and SCR will be operational when Cane Island 4 is proposed to begin commercial operation in May 2011.

b. The capital cost associated with installation of SCR is approximately $5 million.

c. The capital and operating and maintenance (O&M) costs associated with SCR installation have been included in the cost estimate for the proposed Cane Island 4 generating unit.

d. The costs associated with the installation of the SCR are not separately identified in the Cane Island 4 Need for Power Application. However, the capital cost associated with installation of SCR is included in the *Total Installed Capital Cost* estimate presented in Table 9-3 on page 9-12 of the Cane Island 4 Need for Power Application, and the O&M cost associated with SCR is included in the variable O&M estimate presented on Page 9-

13 of the Cane Island 4 Need for Power Application. The capital cost associated with installation of SCR is approximately $5 million and the annual O&M cost (including maintenance and ammonia consumption) for SCR is approximately $241,000 per year (in 2008 dollars).

5. **In the first paragraph of Section 9.1.8 Water Usage, on page 9-3 of the Need for Power Application, it states that "[w]ater for cooling tower makeup is expected to be reclaimed water (treated wastewater). . . . . It is expected that a maximum of approximately 3.0 million gallons per day (mgd) will be required." With regard to the FMPA's projected water usage, please respond to the following:**
   a. **Please explain or describe the reliability of the reclaimed water resources;**
   b. **Please identify or describe the estimated costs associated with FMPA's projected usage of reclaimed water;**
   c. **Please explain or describe whether the costs identified in interrogatory no. 5b have been included within the cost estimates for Cane Island 4; and**
   d. **If the response to Interrogatory No. 5c is yes, please identify or describe where the costs associated with FMPA's projected usage of reclaimed water can be found in FMPA's need filing.**

Response:

a. Reclaimed water resources will be provided by the Toho Water Authority through an existing pipeline. The Toho Water Authority has reliably served the existing units at the Cane Island Power Park, and has provided assurances to FMPA that the incremental reclaimed water needs associated with the proposed Cane Island 4 generating unit can be met. In addition, Cane Island 4 is being permitted to allow use of ground water from on-site wells in the event that the reclaimed water is not available due to a pipeline break or some other event.

b. The estimated annual cost associated with the use of reclaimed water for the proposed Cane Island 4 generating unit is approximately $540,000 per year (in 2008 dollars).

c. The cost associated with reclaimed water has been included in the variable O&M cost estimate for the proposed Cane Island 4 generating unit presented on Page 9-13 of the Cane Island 4 Need for Power Application.

d. The cost associated with the use of reclaimed water is not separately identified in the Cane Island 4 Need for Power Application. However, the annual cost associated with reclaimed water is included in the variable O&M cost estimate presented on page 9-13 of the Cane Island 4 Need for Power Application. The estimated annual cost associated with the use of reclaimed water is approximately $540,000 per year (in 2008 dollars).

6. **In the Need for Power Application, FMPA identified a new fire protection water system in paragraph two of Section 9.1.8 Water Usage, on page 9-3. Please respond to the following:**
   a. **Please identify or describe the capital and O&M costs associated with the new fire protection water system;**
   b. **Please explain or describe whether FMPA has included the costs of the new fire protection water system in its cost estimates for Cane Island 4; and**
   c. **If the response to interrogatory no. 6b is yes, please identify or describe where the costs associated with the new fire protection water system can be found in FMPA's need filing.**

Response:

a. The capital cost associated with installation of the new fire protection water system is approximately $400,000. O&M costs for the new fire protection water system were not separately developed, but are included in the total fixed and variable O&M costs. It is estimated that the O&M costs associated with the fire protection system are approximately $150,000 per year, in 2008 dollars of the fixed O&M estimate for the proposed Cane Island 4 generating unit.

b. The cost of the new fire protection water system is included in the capital and O&M cost estimates for the proposed Cane Island 4 generating unit presented in Table 9-3 on Page 9-12 of the Cane Island 4 Need for Power Application.

c. The costs associated with the new fire protection water system are not separately identified in the Cane Island 4 Need for Power Application. However, the capital costs associated with the new fire protection water system are included in the *Total Installed Capital Cost* estimate presented in Table 9-3 on page 9-12 of the Cane Island 4 Need for Power Application, and the O&M costs associated with the new fire protection water system are included in the fixed O&M estimate presented on page 9-12 of the Cane Island 4 Need for Power Application. The capital cost associated with the new fire protection water system is approximately $400,000, and the O&M costs associated with the new fire protection water system are estimated to be approximately $150,000 per year, in 2008 dollars of the fixed O&M estimate for the proposed Cane Island 4 generating unit.

7. In the Need for Power Application, FMPA identified a demineralized water tank on page 9-4 of Section 9.1.8 Water Usage. With regard to the demineralized water tank, please respond to the following:

a. Please identify or describe the capital costs for the installation of a new demineralized water tank.

b. Please explain or describe whether FMPA has included the cost of a new demineralized water tank in its cost estimates for Cane Island 4.

c. If the response to Interrogatory No. 7b is yes, please identify or describe where the cost of a new demineralized water tank can be found in FMPA's need filing.

Response:

a. The estimated capital cost associated with the new demineralized water tank is approximately $1,600,000.

b. The cost of the new demineralized water tank is included in the capital cost estimate for the proposed Cane Island 4 generating unit.

c. The cost of the new demineralized water tank is not separately identified in the Cane Island 4 Need for Power Application. However, the capital cost associated with the new demineralized water tank is included in the *Total Installed Capital Cost* estimate presented in Table 9-3 on page 9-12 of the Cane Island 4 Need for Power Application. The capital cost associated with the new demineralized water tank is approximately $1,600,000.

8. In Section 9.1.9 Project Process Wastewaters, on page 9-4 of the Need for Power Application, FMPA identifies five major sources of wastewater. With regard to the five sources of wastewater, identified in this section, please respond to the following:

a. Please identify or describe the cost estimates for processing the five major sources of wastewater;

b. Please explain or describe whether FMPA has included the costs of the five major sources of wastewater in its cost estimates for Cane Island 4; and

c. Please explain or describe whether FMPA has included the costs associated with its compliance with wastewater-related environmental rules/regulations in its cost estimates for Cane Island 4.

Response:

a. The costs for processing the five major sources of wastewater are minimal, but have not been separately developed. The costs for processing the five major sources of wastewater are included in the capital and O&M costs on pages 9-12 and 9-13 of the Cane Island 4 Need for Power Application. Response 5b provides a more detailed discussion..

b. The costs associated with the five major sources of wastewater from the proposed Cane Island 4 generating unit have been included in the capital and O&M costs. Three of the five wastewaters, consisting of the vast majority of process wastewaters, will be returned to the Toho Water Authority and in return Toho Water Authority will consider the amount of wastewater that is returned to the system as a credit towards the reclaimed water requirements of the proposed Cane Island 4 generating unit, resulting in a reduction to associated costs. The analysis presented in the Cane Island 4 Need for Power Application does not reflect such a credit towards reclaimed water usage (i.e. a decrease in costs associated with reclaimed water requirements). The other two wastewater streams go the existing septic system and an onsite percolation pond.

c. To my knowledge capital and O&M costs for all wastewater related rules/regulations have been included in the Cane Island 4 Need for Power Application.

The answer to Question No. 1 of Staff's First Set of Interrogatories (Nos. 1-8) was provided by Bradley Kushner (consultant to FMPA), Black & Veatch Corporation, 11401 Lamar Avenue, Overland Park, Kansas 66211. Answers to Question Nos. 2-8 of Staff's First Set of Interrogatories (Nos. 1-8) was provided by Myron Rollins (consultant to FMPA), Black & Veatch Corporation, 11401 Lamar Avenue, Overland Park, Kansas 66211.

Dated this 23rd day of June, 2008.

HOPPING GREEN & SAMS, P.A.

Gary V. Perko
Hopping Green & Sams, P.A.
123 S. Calhoun Street
Tallahassee, FL 32314
(850) 222-7500 (telephone)
(850) 224-8551 (facsimile)
Email: GPerko@hgslaw.com

Attorney for Florida Municipal Power Agency

AFFIDAVIT

STATE OF KANSAS)

COUNTY OF JOHNSON)

I hereby certify that on this 16th day of June, 2008, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Bradley E. Kushner, who is known to me, and he/she acknowledged before me that he/she provided the answers to interrogatory number 1 from STAFF'S FIRST SET OF INTERROGATORIES TO FLORIDA MUNICIPAL POWER AGENCY (NOS. 1-8) in Docket No. 080253-EM, and that the responses are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 16th day of June, 2008.

Bradley E Kushner

Notary Public
State of Kansas, at large
Marsha M. Pennington
My Commission Expires:
7-30-2011

MARSHA M. PENNINGTON NOTARY PUBLIC STATE OF KANSAS

AFFIDAVIT

STATE OF KANSAS)

COUNTY OF JOHNSON)

I hereby certify that on this _____ day of _____, 2008, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Myron R. Rollins, who is known to me, and 2, 3, 4, 5, 6, 7, 8 from STAFF'S FIRST SET OF INTERROGATORIES TO FLORIDA MUNICIPAL POWER AGENCY (NOS. 2-8) in Docket No. 080253-EM, and that the responses are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 16th day of June, 2008.

Myron Rollins

Notary Public
State of Kansas, at large
Marsha M. Purinton
My Commission Expires:
1-30-2011

MARSHA M. PURINTON NOTARY PUBLIC STATE OF KANSAS

2

FMPA's Responses to Staff's Second Set of Interrogatories (Nos. 9-20)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition to determine need for Cane Island Power Park Unit 4 electrical power plant in Osceola County, by Florida Municipal Power Agency.	DOCKET NO. 080253-EM DATED: JUNE 23, 2008

FLORIDA MUNICIPAL POWER AGENCY RESPONSES TO STAFF'S SECOND SET OF INTERROGATORIES (NOS. 9 - 20)

Florida Municipal Power Agency (FMPA) pursuant to Rule 28-106.206, Florida Administrative Code (F.A.C.), and Rule 1.340, Florida Rules of Civil Procedure, hereby responds to Staffs Second Set of Interrogatories (Nos. 9-20).

INTERROGATORIES

9. **Please refer to pages 6 - 8 of the direct testimony of Witness Kushner. Please explain or describe whether the High CO_2 scenario economic evaluation (present value analysis with and without Cane Island 4) would change using a fuel price forecast consistent with the underlying Senate legislation (S.2191).**

Response: The magnitude of the present value costs (both with and without Cane Island 4) would change if the High Regulated CO_2 sensitivity reflected a fuel price forecast consistent with an analysis of S.2191 that was integrated with CO_2 emissions allowance price projections. However, the relative economics between the expansion plan including Cane Island 4 in 2011 compared to the expansion plan without Cane Island 4 in 2011 would likely not be significantly altered. Analysis of Table 5 of Exhibit __ [BEK-5] of Witness Kushner's testimony indicates that there is relatively little variation in cumulative present worth cost (CPWC) savings between the three different

regulated CO_2 sensitivities that were considered in the Cane Island 4 Need for Power Application.

10. Please refer to Interrogatory No. 9. Please explain or describe any and all changes that would result from an analysis using a fuel price forecast consistent with the underlying Senate legislation (S.2191).

Response: As of the time that the Cane Island 4 Need for Power Application was prepared, there was no fully integrated forecast of fuel and emissions allowance prices that corresponded to S.2191 available for analysis. While the US EPA developed an analysis of CO_2 emissions allowance prices (which were utilized in the High Regulated CO_2 sensitivity in the Cane Island 4 Need for Power Application), the EPA analysis did not provide integrated fuel price projections.

It is difficult to speculate as to the changes that would result from performing an analysis based on integrated fuel and emissions allowance price projections corresponding to S.2191, since such changes would be dependent upon a number of factors. However, as discussed in the response to Staff's Interrogatory No. 9, Table 5 of Exhibit __ [BEK-5] of Witness Kushner's testimony indicates that there is relatively little variation in cumulative present worth cost (CPWC) savings between the three different regulated CO_2 sensitivity cases that were considered in the Cane Island 4 Need for Power Application. Consideration of a fourth regulated CO_2 sensitivity case would likely not have significant impact on the relative cumulative present worth costs savings between the expansion plan with Cane Island 4 in 2011 compared to the expansion plan without Cane Island 4 in 2011.

11. **Please refer to Section 20.0, pages 20-2 and 20-3, of the Need for Power Application. Of the nine scenarios identified, please identify or describe which scenarios consider the impact of currently proposed green-house-gas legislation.**

Response: The following cases from Section 20.1, Scenario 1 – Conventional Expansion Scenario (pages 20-2 and 20-3 of the Cane Island 4 Need for Power Application), include the impact of currently proposed greenhouse gas legislation. The list below also includes the proposed greenhouse gas legislation on which the case was based.

- Section 20.1.1.7 – Regulated CO_2 Case (S.280)
- Section 20.1.1.8 – High Fuel with Regulated CO_2 Case (S.280)
- Section 20.1.1.9 – High Regulated CO_2 Case (S.2191, recently amended to S.3036)

12. **Please refer to page 8 of the direct testimony of Witness Kushner. Please explain or describe whether the EPA's recently developed CO_2 cost estimates for S.2191 are still current.**

Response:

The EPA Analysis of S.2191 referred to in Witness Kushner's testimony was dated March 14, 2008. The EPA released an updated analysis of S.2191, also dated March 14, 2008, which reflects updates made May 5, 2008. However, the May 5, 2008 updates consisted of minor changes to a few slides that were immaterial to the projections of CO_2 emissions allowance prices that were presented in the EPA's March 14, 2008 analysis of S.2191 (and subsequently reflected in the Cane Island 4 Need for Power Application). The CO_2 emissions allowance price estimates developed by the EPA in its analysis of

S.2191 that were used in the Cane Island 4 Need for Power Application (and referred to in Witness Kushner's testimony) are still current.

13. **If the response to Interrogatory No. 12 above is no, please explain or describe what factors, if any, have impacted the validity of the cost estimates.**

Response: Please refer to the response to Staff's Interrogatory No. 12, which demonstrates that the EPA's estimates of CO_2 emissions allowance prices for S.2191 that were referred to in Witness Kushner's testimony are still current.

14. **Please refer to Section 20, pages 20-2 and 20-3, of the Need for Power Application. Please identify or describe the sources used to derive the fuel-price forecasts used for each scenario. As part of this response, please include the purchase prices and transportation costs for each scenario.**

Response: The sources used to derive the fuel price forecasts for the cases presented on pages 20-2 and 20-3 of the Cane Island 4 Need for Power Application are listed below. Please note that the fuel price projections for use in the electric power sector developed by the EIA and presented in AEO2007 do not explicitly identify the transportation prices to the FRCC region, but these costs are included in the projected costs per million British Thermal Units (MBtu). As discussed on page 19-2 of the Cane Island 4 Need for Power Application, the economic analyses performed for the cases outlined below include costs for 20,000 MBtu of incremental firm natural gas transportation at a cost of $1.28/MBtu, and any natural gas in excess of existing and incremental firm natural gas transportation capacity would incur an adder of $0.598/MBtu.

Sources for Fuel Price Forecasts:

- Reference Case: AEO2007 Reference Case for FRCC region (natural gas and fuel oil) and Georgia/Florida region (coal).

- High Fuel Price Case: AEO2007 High Price Case, adjusted for delivery to the FRCC region as discussed on pages 7-17 and 7-19 of the Cane Island 4 Need for Power Application.
- Low Fuel Price Case: AEO2007 Low Price Case, adjusted for delivery to the FRCC region as discussed on pages 7-19 and 7-20 of the Cane Island 4 Need for Power Application.
- High Load Case: AEO2007 Reference Case for FRCC region (natural gas and fuel oil) and Georgia/Florida region (coal).
- Low Load Case: AEO2007 Reference Case for FRCC region (natural gas and fuel oil) and Georgia/Florida region (coal).
- High Capital Case: AEO2007 Reference Case for FRCC region (natural gas and fuel oil) and Georgia/Florida region (coal).
- Regulated CO_2 Case: EIA S.280 Core Case from the EIA's *Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007*, adjusted for delivery to the FRCC region as discussed on page 7-43 of the Cane Island 4 Need for Power Application.
- High Fuel with Regulated CO_2 Case: AEO2007 High Price Case, adjusted for delivery to the FRCC region as discussed on pages 7-17 and 7-19 of the Cane Island 4 Need for Power Application.
- High Regulated CO_2 Case: AEO2007 Reference Case for FRCC region (natural gas and fuel oil) and Georgia/Florida region (coal).

15. **Please refer to Section 20 of the Need for Power Application and to Exhibits BEK-2, BEK-3, and BEK-4, attached to the direct testimony of Witness**

Kushner. Please explain or describe whether FMPA assigns any weights or probabilities to the alternative fuel-price forecasts.

a. If yes, please explain or describe what weights or probabilities FMPA assigns to each alternative.

b. If no, please explain why FMPA does not assign any weights or probabilities to the alternative fuel-price forecasts.

c. If the response to Interrogatory No. 15a is yes, please explain or describe if the weights or probabilities equal to 1.00 or 100%.

Response:

a. FMPA has not assigned any weights or probabilities to the alternative fuel price forecasts.

b. As illustrated in Table 5 of Exhibit __[BEK-5] to Witness Kushner's testimony, the expansion plans including operation of the proposed Cane Island 4 beginning in 2011 represent the most cost-effective expansion plans for each of the five alternative fuel price sensitivities (including those related to potential future regulation of CO_2 emissions and inclusion of corresponding costs) considered. As a result, FMPA did not consider it necessary to perform a probabilistic analysis to supplement the evaluations included in the Cane Island 4 Need for Power Application.

c. Not applicable, as the response to Staff's Interrogatory 15a is "no."

16. Please refer to Exhibits BEK-2 and BEK-3 attached to the direct testimony of Witness Kushner and to Table 7-3 of the Need for Power Application. Please explain or describe why the natural gas prices in Exhibits BEK-2 and BEK-3 are different from the prices in Table 7-3 of the Need for Power Application.

Response: There are two reasons for the differences between the natural gas price projections presented in Table 7-3 and those presented in Exhibits BEK-2 and BEK-3 of the Cane Island 4 Need for Power Application. One reason for the differences noted is that the prices presented in Table 7-3 are in real 2005 dollars, and the prices presented in

Exhibit BEK-2 and BEK-3 are in nominal dollars (which were calculated using the 2.3 percent general inflation rate used consistently throughout the Cane Island Need for Power Application).

The second reason for the differences noted is that the natural gas prices presented in Table 7-3 represent projections of prices for natural gas at the Henry Hub delivery point, while the natural gas prices projections presented in Exhibits BEK-2 and BEK-3 represent the cost of natural gas for use in the electric power sector in the Florida Reliability Coordinating Council (FRCC) region. The natural gas (and the other fuel price projections) presented in Table 7-3 were intended to illustrate the differentials in prices projected between the AEO2007 Reference Case and the AEO2007 High Price Case. The AEO2007 High Price Case did not include projections of fuel prices for use in the electric power sector in the FRCC region (as were included in the AEO2007 Reference Case), so in order to provide a consistent comparison Table 7-3 presents the Henry Hub natural gas price projections, rather than FRCC-specific natural gas price projections.

The natural gas price projections presented in Table 1 of Exhibit BEK-2 correspond to the natural gas prices projections presented in Table 7-1 of the Cane Island 4 Need for Power Application, after conversion to nominal dollars as described previously. The natural gas price projections presented in Table 3 of Exhibit BEK-3 correspond to the natural gas price projections presented in Table 7-5 of the Cane Island 4 Need for Power Application, after conversion to nominal dollars as described previously.

17. **Please refer to Exhibits BEK-2 and BEK-3 attached to the direct testimony of Witness Kushner and to Table 7-3 of the Need for Power Application. Please explain or describe whether the difference between the natural gas prices in Exhibits BEK-2 and BEK-3 and those in Table 7-3 of the Need for Power Application are attributable to an "inflation factor" or a set of factors. If so, please identify or describe the factor(s).**

Response:

Please refer to the response to Staff's Interrogatory No. 16 for discussion of the factors which account for the differences between the natural gas price projections presented in Table 7-3 and those presented in Exhibits BEK-2 and BEK-3 of the Cane Island 4 Need for Power Application.

18. **Please refer to pages 3-4 of the direct testimony of Witness Kushner. Please identify or describe the changes in the assumptions of the 2007 EIA fuel-price forecasts, from the prior EIA fuel-price forecast, that affected the forecasted price levels.**

Response: Projections of supply and demand for the fuels used to produce energy are the primary factors that will affect fuel price projections between the 2007 EIA fuel price forecast and the prior EIA fuel price forecast (AEO2007 and AEO2006). Table 1 includes a comparison of forecast consumption by fuel type in the years 2010, 2020, and 2030 for liquid fuels, natural gas, coal, and nuclear power, as projected in AEO2006 and AEO2007. The data presented in Table 1 below is based on information from *Table 1* of the *Overview* section of AEO2007, titled *Total energy supply and disposition in the AEO2007 and AEO2006 reference cases, 2005-2030.*

Table 1 Comparison of Consumption by Fuel Type Between AEO2006 and AEO2007 [1]			
Consumption (quadrillion Btu)	Percent Change from AEO2006 to AEO2007		
	2010	2020	2030
Liquid Fuels	-3.20%	-3.39%	-2.65%
Natural Gas	2.87%	-2.38%	-2.75%
Coal	-3.39%	-1.30%	-1.01%
Nuclear Power	-2.49%	1.54%	2.64%

[1] Based on data from AEO2007, Page 14, Table 1 - *Total energy supply and disposition in the AEO2007 and AEO2006 reference cases, 2005-2030.*

Table 2 compares projections of total electricity generation, natural gas supply, coal supply, and petroleum supply between AEO2006 and AEO2007 for the years 2008 through 2027. The data presented in Table 2 is based on information from various tables in AEO2007 and AEO2006, as specified in Table 2.

Table 2
Comparison of Total Electricity Generation and Natural Gas, Coal, and Petroleum Supply Between AEO2006 and AEO2007 [1]

Year	Total Electricity Generation (billion kWh)		Total Natural Gas Supply (trillion cubic feet)		Total Coal Supply (million short tons)		Total Primary Petroleum Supply (million barrels per day)	
	AEO2006	AEO2007	AEO2006	AEO2007	AEO2006	AEO2007	AEO2006	AEO2007
2008	4,256	4,263	22.55	23.35	1,198	1,152	21.49	21.03
2009	4,318	4,330	22.71	23.72	1,226	1,169	21.81	21.30
2010	4,388	4,392	23.00	23.97	1,235	1,195	22.21	21.49
2011	4,440	4,464	23.48	24.13	1,246	1,222	22.55	21.81
2012	4,534	4,534	24.06	24.52	1,265	1,234	22.85	22.04
2013	4,596	4,593	24.56	24.75	1,270	1,246	23.10	22.31
2014	4,660	4,656	24.96	25.04	1,273	1,272	23.35	22.51
2015	4,727	4,721	25.54	25.29	1,277	1,284	23.57	22.78
2016	4,807	4,787	25.95	25.48	1,291	1,299	23.83	23.04
2017	4,880	4,838	26.11	25.54	1,310	1,316	24.10	23.20
2018	4,955	4,897	26.28	25.67	1,329	1,331	24.38	23.45
2019	5,030	4,962	26.48	25.88	1,349	1,351	24.64	23.73
2020	5,108	5,037	26.54	26.21	1,391	1,377	24.87	23.94
2021	5,180	5,097	26.56	26.18	1,433	1,410	25.10	24.23
2022	5,255	5,170	26.55	26.15	1,478	1,454	25.33	24.51
2023	5,329	5,239	26.61	26.11	1,515	1,489	25.56	24.75
2024	5,417	5,317	26.62	26.11	1,556	1,532	25.85	25.01
2025	5,491	5,395	26.60	26.24	1,593	1,582	26.12	25.22
2026	5,579	5,478	26.61	26.08	1,633	1,628	26.43	25.61
2027	5,665	5,558	26.53	26.10	1,675	1,659	26.76	25.92

[1] Data presented in this table is from Reference Case Table 8 (total electricity generation), Reference Case Table 13 (total natural gas supply), Reference Case Table 15 (total coal supply), and Reference Case Table 11 (total primary petroleum supply) from *AEO2006* and *AEO2007*.

As shown in Table 2, AEO2007 projects a lower level of electricity generation than AEO2006. Total natural gas supply (reflecting production and net imports, including liquefied natural gas, or LNG) is expected to increase through 2014 in AEO2007 compared to AEO2006, and then decrease annually through 2030. Annual total coal supply (reflecting production, imports, and exports) is expected to decrease in AEO2007 as compared to AEO2006. Annual total liquid fuels supply (reflecting production, imports, and exports) is expected to decrease in AEO2007 as compared to AEO2006.

19. Please refer to pages 3-4 of the direct testimony of Witness Kushner. With respect to the 2007 EIA fuel price forecast and the prior fuel price forecast, please explain or describe the changes in the deflation factors that were used to convert from real prices to nominal prices (or from nominal prices to real prices).

Response:

The EIA evaluates gross domestic product (GDP) and energy prices on a nominal dollar basis using a contemporaneous deflator series from each AEO. Each AEO presents a "real" GDP measure and a matched price index. AEO2006 and AEO2007 both use the year 2000 as the reference year for the "GDP Chain-type Price Index" – that is, a value of 1.0 is assigned to the GDP Chain-type Price Index for the year 2000. The annual GDP Chain-type Price Indices are presented in *Table 19. Macroeconomic Indicators* of AEO2006 and AEO2007. The annual GDP Chain-type Price Indices from AEO2006 and AEO2007 for the years 2008 through 2027 are presented in Table 3. In general, the GDP Chain-type Price Indices are lower in AEO2007 than in AEO2006, which results in greater increases in real projections of dollar denominated values.

Table 3 AEO2006 and AEO2007 GDP Chain-type Price Indices (Reference Year : 2000 = 1.000) [1]		
Year	GDP Chain-type Price Indices (Reference Year : 2000 = 1.000)	
	AEO2006	AEO2007
2008	1.185	1.210
2009	1.209	1.231
2010	1.235	1.253
2011	1.264	1.276
2012	1.296	1.299
2013	1.330	1.321
2014	1.363	1.343
2015	1.398	1.366
2016	1.433	1.390
2017	1.471	1.415
2018	1.512	1.441
2019	1.554	1.468
2020	1.597	1.495
2021	1.640	1.523
2022	1.684	1.553
2023	1.729	1.584
2024	1.773	1.616
2025	1.818	1.648
2026	1.863	1.680
2027	1.909	1.713
[1] Source: *Table 19. Macroeconomic Indicators* of AEO2006 and AEO2007		

20. Please refer to pages 3- 4 of the direct testimony of Witness Kushner. Please explain or describe whether FMPA intends to revise its fuel-price forecasts in light of the price increases that have occurred since late April 2008.

Response: FMPA does not plan on revising its fuel price forecast in light of price increases that have occurred since late April 2008. The range of fuel price sensitivities (including those related to potential future regulation of CO_2 emissions and inclusion of corresponding costs) that were considered in the Cane Island 4 Need for Power Application provide a wide range of fuel price sensitivities, allowing for a robust evaluation of the cost effectiveness of the proposed Cane Island 4.

All of the foregoing answers to Staff's Second Set of Interrogatories (Nos. 9-20) were provided by Bradley Kushner (consultant to FMPA), Black & Veatch Corporation, 11401 Lamar Avenue, Overland Park, Kansas 66211.

Dated this 23rd day of June, 2008.

HOPPING GREEN & SAMS, P.A.

Gary V. Perko
Hopping Green & Sams, P.A.
123 S. Calhoun Street
Tallahassee, FL 32314
(850) 222-7500 (telephone)
(850) 224-8551 (facsimile)
Email: GPerko@hgslaw.com

Attorney for Florida Municipal Power Agency

AFFIDAVIT

STATE OF KANSAS)

COUNTY OF JOHNSON)

I hereby certify that on this 16th day of June, 2008, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Bradley E. Kushner, who is known to me, and he/she acknowledged before me that he/she provided the answers to interrogatory number 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20 from STAFF'S SECOND SET OF INTERROGATORIES TO FLORIDA MUNICIPAL POWER AGENCY (NOS. 9-20) in Docket No. 080253-EM, and that the responses are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 16th day of June, 2008.

Bradley E Kushner

Notary Public
State of Kansas, at large
Marsha M. Purnell
My Commission Expires:
7-30-2011

NOTARY PUBLIC STATE OF KANSAS

3

FMPA's Responses to Staff's Third Set of Interrogatories (Nos. 21-29)

HEARING EXHIBIT - 00000029

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition to determine need for Cane Island Power Park Unit 4 electrical power plant in Osceola County, by Florida Municipal Power Agency.	DOCKET NO. 080253-EM DATED: JULY 2, 2008

JUL - 2
FLORIDA PUBLIC SERVICE COMMISSION
OFFICE OF THE GENERAL COUNSEL

FLORIDA MUNICIPAL POWER AGENCY RESPONSES TO STAFF'S THIRD SET OF INTERROGATORIES (NOS. 21 - 29)

Florida Municipal Power Agency (FMPA) pursuant to Rule 28-106.206, Florida Administrative Code (F.A.C.), and Rule 1.340, Florida Rules of Civil Procedure, hereby responds to Staffs Third Set of Interrogatories (Nos. 21-29).

INTERROGATORIES

21. Regarding the assumed economic parameters, please explain or describe how the FMPA members analyzed and selected 2.3% as the escalation rate, i.e., the general inflation rate?

Response: The general inflation and escalation rates of 2.3 percent were selected by FMPA based a projection of the long term consumer price index (CPI) of 2.3 percent included in a memo prepared for FMPA by RW Beck. FMPA chose to align their assumed escalation rate with this projection of the CPI.

22. Please explain or describe the basis for the assumed 5.00% cost rate for new debt.

Response: The assumed annual cost rate for new debt used throughout the Cane Island 4 Need for Power Application is based on the long-term tax exempt municipal bond rate at the time the economic parameters were developed. For comparison purposes, the 30 year municipal bond rate presented June 17, 2008 on Bloomberg.com (www.bloomberg.com/markets/rates) for AAA rated, tax exempt insured revenue bonds was 4.85 percent.

The 5.0 percent interest rate used in the Application does not include bond issuance fees, which were accounted for separately in the Cane Island 4 Need for Power Application.

23. Please explain or describe how the FMPA members use the assumed 2.3% escalation rate in the evaluation process.

Response: The 2.3 percent escalation rate was applied to capital costs and operating and maintenance costs in all economic evaluations throughout the Cane Island 4 Need for Power Application. The projections of fuel and emission allowance price forecasts provided by the Energy Information Administration (which were used throughout the Cane Island 4 Need for Power Application) were presented in real 2005 dollars, and the 2.3 percent general inflation rate was used to convert these costs to nominal dollars.

24. Please explain or describe how the FMPA members use the assumed 5.0% rate for interest during construction in the evaluation process.

Response: The 5.0 percent interest during construction rate was used consistently throughout the Cane Island 4 Need for Power Application in the economic evaluation of supply-side alternatives to calculate the interest during construction associated with each of the generating unit alternatives. The interest during construction required for Cane Island 4 was estimated based on a projected monthly cash flow for project expenditures prior to commercial operation. The interest during construction for all other alternatives was estimated assuming interest would accrue for one half of the construction period for each alternative.

25. Please explain or describe how the FMPA members use the assumed 5.0% present worth discount rate in the evaluation process.

Response: The 5.0 percent present worth discount rate was used consistently throughout this Application to discount the annual system costs in the economic evaluations to 2008 values, and

the sum of the annual present worth system costs were aggregated to determine the cumulative present worth costs for each expansion plan considered. These cumulative present worth costs were then compared to identify the least-cost capacity expansion plan under the base case and for each of the sensitivity cases considered.

26. Please explain or describe the basis for the 25 year 7.824% fixed charge rate. For purposes of this response, please discuss all assumptions and show all calculations.

Response: Different generating technologies are assumed to have different economic lives and therefore different financing terms. Simple cycle combustion turbines are assumed to have a 25 year financing term. All levelized fixed charge rate calculations assume the 5.0 percent tax exempt municipal bond interest rate, a 2.0 percent bond issuance fee, an assumed 0.50 percent annual property insurance cost, and a debt service reserve fund (DSRF) equal to six months of debt service requirement earning interest at an interest rate equal to the bond interest rate of 5.0 percent. The resulting 25 year fixed charge rate is 7.824 percent.

The levelized fixed charge rate is essentially the capital recovery factor, adjusted to include the bond issuance fee and the debt service reserve fund, plus 0.50 percent for property insurance, and was calculated as follows:

For the 25 year fixed charge rate where i = 5.0 percent, n = 25 years, DSRF = 0.5 year, bond issuance fees (fees) = 2.0 percent, and property insurance = 0.5 percent:

Capital Recovery Factor (CRF) =

$$\frac{i \times [(1+i)^n]}{[(1+i)^n - 1]} = \frac{0.05 \times [(1+0.05)^{25}]}{[(1+0.05)^{25} - 1]} = 0.07095 = 7.095 \text{ Percent}$$

Adjusted CRF (ACRF) =

$$\frac{(1 - (i \times DSRF)) \times CRF}{[1 - fees - (DSRF \times CRF)]} = \frac{(1 - (0.05 \times 0.5)) \times 0.07095}{[1 - 0.02 - (0.5 \times 0.07095)]} = 0.07324 = 7.324 \text{ Percent}$$

Levelized Fixed Charge Rate =

ACRF + property insurance = 0.07324 + 0.005 = 0.07824 = 7.824 Percent

27. Please explain or describe the basis for the 30 year 7.194% fixed charge rate. For purposes of this response, please discuss all assumptions and show all calculations.

Response: Different generating technologies are assumed to have different economic lives and therefore different financing terms. Combined cycle combustion turbines are assumed to be financed over 30 years. All levelized fixed charge rate calculations assume the 5.0 percent tax exempt municipal bond interest rate, a 2.0 percent bond issuance fee, an assumed 0.50 percent annual property insurance cost, and a debt service reserve fund (DSRF) equal to six months of debt service requirement earning interest at an interest rate equal to the bond interest rate of 5.0 percent. The resulting 30 year fixed charge rate is 7.194 percent.

The levelized fixed charge rate is essentially the capital recovery factor, adjusted to include the bond issuance fee and the debt service reserve fund, plus 0.50 percent for property insurance, and was calculated as follows:

For the 30 year fixed charge rate where i = 5.0 percent, n = 30 years, DSRF = six months (0.5 year), bond issuance fees (fees) = 2.0 percent, and property insurance = 0.5 percent:

Capital Recovery Factor (CRF) =

$$\frac{i\times[(1+i)^n]}{[(1+i)^n-1]}=\frac{0.05\times[(1+0.05)^{30}]}{[(1+0.05)^{30}-1]}=0.06505=6.505\text{ Percent}$$

Adjusted CRF (ACRF) =

$$\frac{(1-(\,i\times DSRF)\,)\times CRF}{[1-fees-(DSRF\times CRF)]}=\frac{(1-(0.05\times 0.5))\times 0.06505}{[1-0.02-(0.5\times 0.06505)]}=0.06694=6.694\text{ Percent}$$

Levelized Fixed Charge Rate =

ACRF + property insurance = 0.06694 + 0.005 = 0.07194 = 7.194 Percent

28. Please explain or describe how the FMPA members use the two assumed fixed charge rates in the evaluation process.

Response: The two levelized fixed charge rates were applied to all estimated capital expenditures in the economic analyses performed in the Cane Island 4 Need for Power Application. The levelized fixed charge rate, or FCR, represents the sum of a project's fixed charges as a percent of the initial investment cost. When the FCR is applied to the initial investment, the product equals the revenue requirements needed to offset the fixed charges during a given year. The resulting levelized capital cost was factored into the determination of annual system costs for each expansion plan evaluated. The levelized fixed charge rates were applied to all capital expenditures consistently throughout the Application. The 25 year fixed charge rate was applied to simple cycle combustion turbine alternatives, and the 30 year fixed charge rate was applied to combined cycle alternatives.

29. Please identify or describe the assumed capital structure for the Cane Island project with the contributions of all the FMPA members.

Response: FMPA has yet to make a final decision regarding the capital structure for the Cane Island Power Park Unit 4. The analysis assumes that 100% debt financing will be used for the project, but if FMPA finds another scenario more favorable it is capable of implementing it to best suit its needs. Possible funding sources include internal funds, pooled loans, and new long term debt issuances, but FMPA normally utilizes pooled loans and long term debt. The FMPA member contributions are the purchase of power based on the All-Requirements Power Supply Contract with FMPA. The power purchased by members under the All-Requirements Power Supply Contract has demand and energy components for the members' total power supply requirements. There is not a separate component specific to the Cane Island project. FMPA is confident it will be able to issue debt to cover the project cost due to the favorable economics of the project and their excellent credit rating.

The answers to Question Nos. 21 - 29 of Staff's Third Set of Interrogatories (Nos. 21-29) were provided by Myron Rollins (consultant to FMPA), Black & Veatch Corporation, 11401 Lamar Avenue, Overland Park, Kansas 66211.

Dated this 2nd day of July, 2008.

HOPPING GREEN & SAMS, P.A.

Gary V. Perko
Hopping Green & Sams, P.A.
123 S. Calhoun Street
Tallahassee, FL 32314
(850) 222-7500 (tel.); (850) 224-8551 (fax)
Email: GPerko@hgslaw.com

Attorney for Florida Municipal Power Agency

AFFIDAVIT

STATE OF KANSAS)

COUNTY OF JOHNSON)

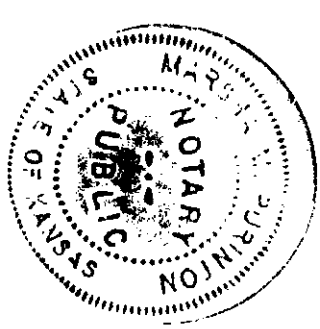
I hereby certify that on this 20th day of June, 2008, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Myron R. Rollins, who is personally known to me, and he/she acknowledged before me that he/she provided the answers to interrogatory numbers 21, 22, 23, 24, 25, 26, 27, 28, 29 from STAFF'S THIRD SET OF INTERROGATORIES TO FLORIDA MUNICIPAL POWER AGENCY (NOS. 21-29) in Docket No. 080253-EM, and that the responses are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 20th day of June, 2008.

Myron Rollins

Marsha M. Runnion
Notary Public
State of Kansas, at large

My Commission Expires:
7-30-2011



4

FMPA's Responses to Staff's Fourth Set of Interrogatories (Nos. 30-31, 34-43, 45-46, 49-50)

HEARING EXHIBIT - 00000037

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition to determine need for Cane Island Power Park Unit 4 electrical power plant in Osceola County, by Florida Municipal Power Agency.	DOCKET NO. 080253-EM DATED: JULY 10, 2008

FLORIDA MUNICIPAL POWER AGENCY RESPONSES TO STAFF'S FOURTH SET OF INTERROGATORIES (NOS. 30 - 50)

Florida Municipal Power Agency (FMPA) pursuant to Rule 28-106.206, Florida Administrative Code (F.A.C.), and Rule 1.340, Florida Rules of Civil Procedure, hereby responds to Staffs Fourth Set of Interrogatories (Nos. 30-50).

INTERROGATORIES & RESPONSES

30. **On page 6, lines 18-23, of his direct testimony, Witness Reedy discusses the retirement of units owned by Fort Pierce Utilities Authority, Lake Worth, and Kissimmee Utility Authority. Please identify or describe the retirement dates and summer capacities of each of the units identified above.**

Response: Table 3-5 of the Cane Island 4 Need for Power Application presented summer capacities and anticipated retirements dates for the Fort Pierce Utilities Authority, Lake Worth, and Kissimmee Utility Authority units that were current as of the time the Cane Island 4 Need for Power Application was being prepared. Subsequent to that time, the Fort Pierce units were retired as of the dates indicated in the update to Table 3-5, which is presented below as Table 30. The anticipated retirement dates of the Lake Worth and Hansel units presented in Table 3-5 have not changed since the Cane Island 4 Need for Power Application was filed. It should be noted that future unit retirements are

contingent upon agreement of the ARP member that owns the unit to affect the retirement of the unit.

Table 30 provides an update to Table 3-5 of the Cane Island 4 Need for Power Application to clearly present the recent retirements of the Fort Pierce units, as well as future planned unit retirements considered in the Cane Island 4 Need for Power Application.

Table 30
FMPA Recent and Planned Retirements

Unit Identification	Retirement Date	Summer Capacity Retired (MW)	Total Annual Summer Capacity Retired (MW)
Recent Unit Retirements			
Fort Pierce Unit 7	5/31/2008	29	
Fort Pierce Unit 8	5/31/2008	49	
Fort Pierce Combined Cycle	5/31/2008	31	
Fort Pierce D1 and 2	5/31/2008	5	
Total of Recent Unit Retirements			114
Planned Unit Retirements			
Lake Worth Unit 3	5/1/2011	25	
Lake Worth Unit 5	5/1/2011	8	
Lake Worth GT 1	5/1/2011	27	
Lake Worth GT 2	5/1/2011	20	
Lake Worth D1-5	5/1/2011	10	89 [1]
Hansel Combined Cycle	5/1/2012	47	47
Total Planned Unit Retirements			136

[1] Total Annual Summer Capacity Retired does not match sum of individual unit Summer Capacity Retired due to rounding.

31. On page 6, lines 18-23, of his direct testimony, Witness Reedy discusses the units to be retired and how their retirement will affect FMPA's generating capacity. Please respond to the following:

A. Please explain or describe what impact, if any, would there be on the need for Cane Island Unit 4, if none of the units discussed were retired.

Response: As discussed in response to Interrogatory No. 30, the Fort Pierce generating units shown in Table 3-5 of the Cane Island 4 Need for Power Application were retired May 31, 2008. As a result, in responding to this Interrogatory, the Fort Pierce units have been treated as retired and Table 31.A presents the projected annual capacity requirements for a scenario in which none of the Lake Worth units nor Hansel Combined Cycle unit are retired. The resulting need for Cane Island 4 in 2011 illustrated in Table 31.A is 197 MW.

Table 31.A
Projected Reliability Levels – Summer – Base Case Load Forecast – No Unit Retirements Beyond Fort Pierce Units

Year	Net Generating Capacity (MW)	Non-Partial Requirements Purchases (MW)	Partial Requirements Purchases (MW)	Net Firm Planned Capacity Reductions[1] (MW)	Net Firm Capacity Additions[2] (MW)	Net System Capacity (MW)	System Peak Demand[3] (MW)	Reserve Margin[4] (%)	Excess/(Deficit) to Maintain 18% Reserve Margin (MW)
2008	1,318	337	75	(114)	296	1,912	1,545	25.0%	103
2009	1,318	337	120	(114)	296	1,957	1,593	24.7%	98
2010	1,318	237	165	(300)	296	1,717	1,483	17.7%	(3)
2011	1,318	237	45	(299)	296	1,597	1,527	4.7%	(197)
2012	1,318	237	45	(289)	296	1,606	1,560	3.1%	(226)
2013	1,318	237	0	(289)	296	1,561	1,594	-2.1%	(320)
2014	1,318	237	0	(289)	296	1,562	1,630	-4.2%	(362)
2015	1,318	237	0	(289)	296	1,562	1,668	-6.3%	(406)
2016	1,318	237	0	(289)	296	1,562	1,705	-8.4%	(451)
2017	1,318	237	0	(289)	296	1,562	1,744	-10.4%	(496)
2018	1,318	237	0	(289)	296	1,562	1,782	-12.3%	(540)
2019	1,318	237	0	(289)	296	1,562	1,820	-14.2%	(586)
2020	1,318	237	0	(289)	296	1,562	1,859	-16.0%	(631)
2021	1,318	237	0	(289)	296	1,562	1,898	-17.7%	(678)
2022	1,318	237	0	(289)	296	1,562	1,938	-19.4%	(725)
2023	1,318	237	0	(289)	296	1,562	1,978	-21.0%	(772)
2024	1,318	237	0	(289)	296	1,562	2,018	-22.6%	(819)
2025	1,318	237	0	(289)	296	1,562	2,057	-24.1%	(866)
2026	1,318	237	0	(289)	296	1,562	2,098	-25.6%	(914)
2027	1,318	237	0	(289)	296	1,562	2,139	-27.0%	(962)

[1]Reflects annual capacity retirements described in Section 3.0, changes to the ratings of existing nuclear generating resources, and the loss of City of Vero Beach's generating units associated with CROD, all described in Section 3.0.
[2]Firm capacity additions reflect commercial operation of TCEC Unit 1 combined cycle (May 2008).
[3]City of Vero Beach's forecast capacity requirements are no longer included beginning January 1, 2010, when the CROD becomes effective, except for approximately 21 MW of the City of Vero Beach's load resulting from the CROD.
[4]Reserve margin calculated as (Net System Capacity - Partial Requirements Purchases) - (System Peak Demand - Partial Requirements Purchases) / (System Peak Demand - Partial Requirements Purchases).

HEARING EXHIBIT - 00000042

B. Please explain or describe what impact, if any, would there be on the need for Cane Island Unit 4, if only one of the units discussed were retired.

Response: As discussed in response to Interrogatory No. 30, the Fort Pierce generating units shown in Table 3-5 of the Cane Island 4 Need for Power Application were retired May 31, 2008. As a result, in responding to this Interrogatory, the Fort Pierce units have been treated as retired and the listed below, which are included in Attachment 31B, reflect the retirement of only each of the Lake Worth units as well as the Hansel Combined Cycle unit.

1. As illustrated in Table 31.B.1, FMPA will require 222 MW of capacity in 2011 if only Lake Worth Unit 3 is retired.
2. As illustrated in Table 31.B.2, FMPA will require 205 MW of capacity in 2011 if only Lake Worth Unit 5 is retired.
3. As illustrated in Table 31.B.3, FMPA will require 224 MW of capacity in 2011 if only Lake Worth GT1 is retired.
4. As illustrated in Table 31.B.4, FMPA will require 217 MW of capacity in 2011 if only Lake Worth GT2 is retired.
5. As illustrated in Table 31.B.5, FMPA will require 207 MW of capacity in 2011 if only Lake Worth Units D1-5 are retired.
6. As illustrated in Table 31.B.6, FMPA will require 197 MW of capacity in 2011 if only Hansel Combined Cycle (Kissimmee Utility Authority) is retired.

C. Please explain or describe what impact, if any, would there be on the need for Cane Island Unit 4, if two of the units discussed were retired.

Response: As discussed in response to Interrogatory No. 30, the Fort Pierce generating units shown in Table 3-5 of the Cane Island 4 Need for Power Application were retired May 31, 2008. As a result, in responding to this Interrogatory, the Fort Pierce units have been treated as retired. There are 15 possible combinations of retirement of 2 units among the 6 units shown as future unit retirements in Table 30 (presented in the response to Interrogatory No. 30), as summarized below.

1. Lake Worth Unit 3 & Lake Worth Unit 5
2. Lake Worth Unit 3 & Lake Worth GT1
3. Lake Worth Unit 3 & Lake Worth GT2
4. Lake Worth Unit 3 & Lake Worth D1-5
5. Lake Worth Unit 3 & Hansel Combined Cycle
6. Lake Worth Unit 5 & Lake Worth GT1
7. Lake Worth Unit 5 & Lake Worth GT2
8. Lake Worth Unit 5 & Lake Worth D1-5
9. Lake Worth Unit 5 & Hansel Combined Cycle
10. Lake Worth GT1 & Lake Worth GT2
11. Lake Worth GT1 & Lake Worth D1-5
12. Lake Worth GT1 & Hansel Combined Cycle
13. Lake Worth GT2 & Lake Worth D1-5
14. Lake Worth GT2 & Hansel Combined Cycle
15. Lake Worth D1-5 & Hansel Combined Cycle

Tables 31.C.1 through 31.C.15, included in Attachment 31.C, present FMPA's need for additional capacity in 2011 corresponding to the combinations of unit retirements presented previously in this response. Analysis of Tables 31.C.1 through 31.C.15 indicate that FMPA will require 205 MW to 249 MW of additional capacity in 2011 depending on the combination of unit retirements requested in this Interrogatory.

D. Please explain or describe what impact, if any, would there be on the need for Cane Island Unit 4, if all of the units were retired.

Response: This scenario is identical to the scenario outlined in the Cane Island Need for Power Application in Section 13. It reflects the retirement of the Fort Pierce, Lake Worth, and Kissimmee units at their respective retirement dates as stated in Table 30 (presented in response to Interrogatory No. 30). Table 13-1 of the Cane Island 4 Need for Power Application and is provided below for convenience.

Table 13-1
Projected Reliability Levels – Summer – Base Case Load Forecast

Year	Net Generating Capacity (MW)	Non-Partial Requirements Purchases (MW)	Partial Requirements Purchases (MW)	Net Firm Planned Capacity Reductions[1] (MW)	Net Firm Capacity Additions[2] (MW)	Net System Capacity (MW)	System Peak Demand[3] (MW)	Reserve Margin[4] (%)	Excess/(Deficit) to Maintain 18% Reserve Margin (MW)
2008	1,318	337	75	(114)	296	1,912	1,545	25.0%	103
2009	1,318	337	120	(114)	296	1,957	1,593	24.7%	98
2010	1,318	237	165	(300)	296	1,717	1,483	17.7%	(3)
2011	1,318	237	45	(389)	296	1,508	1,527	-1.3%	(286)
2012	1,318	237	45	(426)	296	1,470	1,560	-5.9%	(363)
2013	1,318	237	0	(426)	296	1,425	1,594	-10.6%	(456)
2014	1,318	237	0	(426)	296	1,425	1,630	-12.6%	(498)
2015	1,318	237	0	(426)	296	1,425	1,668	-14.5%	(542)
2016	1,318	237	0	(426)	296	1,425	1,705	-16.4%	(587)
2017	1,318	237	0	(426)	296	1,425	1,744	-18.2%	(632)
2018	1,318	237	0	(426)	296	1,425	1,782	-20.0%	(677)
2019	1,318	237	0	(426)	296	1,425	1,820	-21.7%	(722)
2020	1,318	237	0	(426)	296	1,425	1,859	-23.3%	(768)
2021	1,318	237	0	(426)	296	1,425	1,898	-24.9%	(814)
2022	1,318	237	0	(426)	296	1,425	1,938	-26.4%	(861)
2023	1,318	237	0	(426)	296	1,425	1,978	-27.9%	(908)
2024	1,318	237	0	(426)	296	1,425	2,018	-29.3%	(955)
2025	1,318	237	0	(426)	296	1,425	2,057	-30.7%	(1,002)
2026	1,318	237	0	(426)	296	1,425	2,098	-32.0%	(1,050)
2027	1,318	237	0	(426)	296	1,425	2,139	-33.4%	(1,098)

[1]Reflects annual capacity retirements described in Section 3.0, changes to the ratings of existing nuclear generating resources, and the loss of City of Vero Beach's generating units associated with CROD, all described in Section 3.0.
[2]Firm capacity additions reflect commercial operation of TCEC Unit 1 combined cycle (May 2008).
[3]City of Vero Beach's forecast capacity requirements are no longer included beginning January 1, 2010, when the CROD becomes effective, except for approximately 21 MW of the City of Vero Beach's load resulting from the CROD.
[4]Reserve margin calculated as (Net System Capacity - Partial Requirements Purchases) - (System Peak Demand - Partial Requirements Purchases) / (System Peak Demand - Partial Requirements Purchases).

HEARING EXHIBIT - 00000046

E. Please complete the following chart:

Retiring Unit	Age	Heat Rate	Equivalent Availability Factor
Fort Pierce			
Lake Worth			
Kissimmee			

Response: Table 31.E presents the requested information.

Table 31.E
Unit Age, Heat Rate, and Equivalent Availability Factors

Retiring Unit	Age (Yr)	Heat Rate (Btu/kWh)	Equivalent Availability Factor (Percent)
Fort Pierce Units			
Fort Pierce Unit 7	44	13,414	87.0
Fort Pierce Unit 8	32	12,920	87.0
Fort Pierce Combined Cycle (Note 1)	55	10,540	88.8
Fort Pierce Units D1 and D2	38	10,984	93.6
Lake Worth Units			
Lake Worth Unit 3	44	13,620	87.0
Lake Worth Unit 5	33	10,650	88.3
Lake Worth GT 1	35	15,740	95.4
Lake Worth GT 2	33	10,650	88.3
Lake Worth Units D1-D5	46	10,020	93.9
Kissimmee Unit			
Hansel Combined Cycle	29	10,640	88.3

Note 1. Age is that of the steam turbine portion of this resource. This resource was converted to combined cycle operation in 1990.

34. On page 12, lines 16-21, of his direct testimony, Witness Reedy discusses on-going negotiations with the proposed Gulfstream expansion for natural gas delivery. Please explain or describe in detail the results of any discussions or correspondence FMPA has had with Gulfstream about specific needs to provide natural gas for Cane Island Unit 4, including how much natural gas will be required to operate Cane Island Unit 4.

Response: Gulfstream held a non-binding Open Season the fall of 2007 soliciting interested parties to participate in a proposed expansion of their pipeline system. FMPA submitted an expression of interest for 20,000 Dth/d of incremental capacity during this period. Gulfstream continues to review expansion alternatives, having scaled back initial plans for looping their pipeline. FMPA has continued its discussions with Gulfstream about participating in their expansion once design and cost parameters have become more solidified.

Concurrently, FMPA continues to review their requirements for reliably serving the Cane Island 4 facility. This unit is anticipated to require approximately 30,000 Dth/d for operation as an intermediate unit. Specific discussions with Gulfstream have contemplated the potential of obtaining incremental capacity of 20,000 to 30,000 Dth/d. It is anticipated that existing capacity rights will fulfill a portion of the firm natural gas transportation requirements of Cane Island 4. Analysis of actual requirements for incremental capacity continues as a part of a full review of FMPA's existing subscribed capacity and its projected requirements with the addition of Cane Island Unit 4. FMPA's stated needs have been included in Gulfstream's design for their expansion.

35. **Please refer to page 16, line 22, through page 17, line 4 of the direct testimony of Witness Reedy. Please explain or describe what impact, if any, the addition of energy to the grid from Cane Island 4 will have on the transmission and generating issues in central Florida identified in the 2005 Florida Central Coordinated Study.**

Response: The original Florida Central Coordinated Study (FCCS) study was completed in May 2006 using the Florida Reliability Coordinating Council (FRCC) 2005 databank. The study recommended the construction and upgrade of several 230 kV transmission facilities. Review of this study concluded that significant changes occurred between the time the study was initiated and when the study was completed. Consequently the FRCC decided to restudy the central Florida transmission system using updated information contained in the FRCC 2006 databank. This restudy was completed in July 2006 and the results presented to the Florida Public Service Commission (FPSC) on September 7, 2006 at the 2006 Ten-Year Site Plan Workshop.

In addition to the FCCS 2006 re-study and its results, an updated FRCC planning process was agreed to and presented at the FPSC workshop. This new planning process had the concurrence of the utilities in Florida as well as the FPSC and was intended to more tightly coordinate the transmission planning process in Florida and to ensure that any subsequent facilities proposed for construction would be subject to a uniform and rigorous planning process that would identify impacts and propose solutions. This new planning process includes the NERC standards as well as meeting regional FRCC requirements.

Several coal units which were included in the 2006 FRCC databank have subsequently been removed from consideration. Subsequent to the 2006 FCCS restudy, several generating interconnection / transmission service request studies such as FPL's West County Energy Center Unit 3 (1,219 MW summer net output) have been evaluated through the new FRCC transmission planning process.

FRCC studied Cane Island 4 using the FRCC 2007 databank cases. These cases included the impacts of all incremental generating units since the 2006 FCCS restudy as well as all the remedies and new transmission projects proposed by utilities in Florida. FRCC's review of the impact of Cane Island 4 included modeling generation at Polk Plant , Hines Plant, Midulla Generating Station, Hardee Generating Station, Osceola and Vandolah Plants at full output. Additional sensitivities were performed (Vandolah generation off,

Osceola generation off, Intercession City generation at full output and Intercession City generation off) to analyze the impact of Cane Island 4 to the central Florida region.

The FRCC's Transmission Working Group and Stability Working Group found that the addition of Cane Island 4 will not adversely impact the reliability of the FRCC transmission system.

36. **Please refer to page 20, lines 8-13, of the direct testimony of Witness Reedy. With respect to the demand response program with Publix Super Markets, please identify or describe the amount of FMPA's demand that is reduced by the energy produced by Publix's standby generators.**

Response: The amount of FMPA's peak demand that is reduced as a result of the demand response program with Publix Super Markets is approximately 9 MW.

37. **On page 20, lines 11-13, of his direct testimony, Witness Reedy testifies that since the use of the Publix standby generators must be exercised periodically, their use to reduce FMPA's demand displaces FMPA generation and reduces FMPA's CO_2 and other emissions. Please explain or describe how much CO_2 and other regulated green house gases are emitted by the Publix generators compared to the energy displaced from FMPA generation.**

Response: The Publix generators are estimated to emit approximately 0.73 tons of CO_2 per MWh, while the ARP system-wide average CO_2 emissions were approximately 0.67 tons per MWh in 2007. At the time of FMPA system peaks, FMPA's incremental generation will be its most inefficient and its emissions will be higher than the system average. If the Publix generators are exercised at these times, overall CO_2 emissions will

likely decrease slightly. However, the main purpose of this DSM program is to reduce peak demand on FMPA's system.

38. Please refer to page 19, of the direct testimony of Witness Reedy. Please respond to the following questions related to FMPA's existing conservation and demand-side management (DSM) programs:

A. Please identify or describe how many customers (number and percentage of total customers) are participating in each DSM program offered by each ARP member for the period 2002-2007;

Response: In responding to this Interrogatory, FMPA contacted each ARP member to collect the requested data. Please refer to the following tables, which summarize the number and percentage of total customers participating in each DSM program offered by each ARP member for which data was available for the period 2002 -2007. For each of the tables presented below, the percentage of total customers is based on both residential and commercial customers.

Beaches

	Energy Audit Program		Net Metering		On-Line Energy Audits		Compact Fluorescent Bulbs	
Year	Participants	% of Total	Participants	% of Total	Participants	% of Total	Participants	% of Total
2002	427	1.37%	0	0.00%	0	0.00%	0	0.00%
2003	513	1.64%	0	0.00%	0	0.00%	0	0.00%
2004	444	1.39%	0	0.00%	0	0.00%	0	0.00%
2005	482	1.51%	0	0.00%	0	0.00%	0	0.00%
2006	579	1.80%	0	0.00%	0	0.00%	0	0.00%
2007	316	0.96%	5	0.02%	136	0.41%	7,000	21.27%

Fort Pierce

	Energy Audit Program		Compact Fluorescent Bulbs	
Year	Participants	% of Total	Participants	% of Total
2002	0	0.00%	0	0.00%
2003	0	0.00%	0	0.00%
2004	0	0.00%	0	0.00%
2005	58	0.22%	100	0.38%
2006	31	0.12%	200	0.75%
2007	23	0.09%	300	1.18%

Havana

	Energy Audit Program	
Year	Participants	% of Total
2002	0	0.00%
2003	4	0.31%
2004	6	0.45%
2005	9	0.68%
2006	26	1.90%
2007	22	1.58%

Keys Energy Services

	Energy Audit Program		Tree Planting Incentive		Net Metering		On-Line Energy Audits	
Year	Participants	% of Total	Participants	% of Total	Participants	% of Total	Participants	% of Total
2002	0	0.00%	2000	6.96%	0	0.00%	0	0.00%
2003	170	0.59%	2000	6.89%	0	0.00%	0	0.00%
2004	102	0.35%	2000	6.84%	0	0.00%	0	0.00%
2005	38	0.13%	2000	6.77%	0	0.00%	0	0.00%
2006	100	0.34%	2000	6.78%	0	0.00%	0	0.00%
2007	108	0.37%	2000	6.77%	1	0.00%	23	0.08%

	Bio-Diesel Fleet	
Year	Participants	% of Total
2002	0	0.00%
2003	0	0.00%
2004	0	0.00%
2005	0	0.00%
2006	0	0.00%
2007	33	0.11%

Lake Worth

	On-Line Energy Audits	
Year	Participants	% of Total
2002	0	0.00%
2003	0	0.00%
2004	0	0.00%
2005	0	0.00%
2006	0	0.00%
2007	26	0.10%

Leesburg

	Energy Audit Program		ESCO Projects	
Year	Participants	% of Total	Participants	% of Total
2002	45	0.23%	0	0.00%
2003	50	0.24%	0	0.00%
2004	60	0.28%	1	0.00%
2005	90	0.44%	0	0.00%
2006	115	0.54%	0	0.00%
2007	40	0.19%	0	0.00%

Ocala

	Energy Audit Program		Appliance & Other Rebates		Net Metering	
Year	Participants	% of Total	Participants	% of Total	Participants	% of Total
2002	939	1.99%	1,135	2.41%	0	0.00%
2003	1,113	2.36%	1,299	2.75%	0	0.00%
2004	1,107	2.29%	1,279	2.65%	0	0.00%
2005	1,119	2.26%	1,319	2.66%	0	0.00%
2006	1,305	2.57%	42	0.08%	1	0.00%
2007	940	1.79%	5	0.01%	2	0.00%

	On-Line Energy Audits	
Year	Participants	% of Total
2002	0	0.00%
2003	0	0.00%
2004	0	0.00%
2005	0	0.00%
2006	0	0.00%
2007	197	0.38%

Vero Beach

	On-Line Energy Audits	
Year	Participants	% of Total
2002	0	0.00%
2003	0	0.00%
2004	0	0.00%
2005	0	0.00%
2006	0	0.00%
2007	118	0.35%

B. Please identify or describe the number of DSM audits performed in 2007 by each ARP member;

Response: In responding to this Interrogatory, FMPA contacted each ARP member to collect the requested data. Please refer to the following table which summarizes the DSM audits performed in 2007 by each ARP member for which data was available. The data presented in the following table includes on-line energy audits and reflects residential and commercial customers. Note that the data in the following table may

include more ARP members than in the responses to Interrogatory No. 38A, as complete data for 2002-2007 as requested in Interrogatory No. 38A may not have been available for those ARP members providing information.

DSM Audits Performed in 2007	
Member	Audits
Beaches Energy Services	452
Bushnell	7
Clewiston	10
Fort Meade	8
Fort Pierce	23
Green Cove Springs	8
Havana	22
Keys Energy Services	131
Lake Worth	26
Leesburg	40
Newberry	12
Ocala	1137
Vero Beach	118

C. Please identify or describe the percentage of eligible customers that have utilized each ARP member's DSM audits for the period 2003-2007;

Response: In responding to this Interrogatory, FMPA contacted each ARP member to collect the requested data. Please refer to the following table which summarizes the percentages of eligible customers that have utilized each ARP member's DSM audits for the period 2003-2007 for which data was available. The data presented in the following table includes on-line energy audits and reflects residential and commercial customers.

	Percentage of Eligible Customers Utilizing DSM Audits							
Year	*Beaches*	*Fort Pierce*	*Havana*	*Keys*	*Lake Worth*	*Leesburg*	*Ocala*	*Vero Beach*
2003	1.64%	0.00%	0.32%	0.59%	0.00%	0.24%	2.40%	0.00%
2004	1.39%	0.00%	0.46%	0.35%	0.00%	0.28%	2.32%	0.00%
2005	1.51%	0.26%	0.70%	0.13%	0.00%	0.44%	2.29%	0.00%
2006	1.80%	0.14%	1.96%	0.34%	0.00%	0.54%	2.61%	0.00%
2007	1.37%	0.11%	1.63%	0.44%	0.35%	0.19%	2.23%	0.35%

D. Please identify or describe any DSM programs offered by each ARP member that specifically provide consumer education; and

Response: Please see the following descriptions of customer education programs offered by each ARP member. Additional programs not specifically outlined below are discussed in Section 17.1.2 of the Cane Island 4 Need for Power Application. As discussed in Section 17.1.4 of the Cane Island 4 Need for Power Application, eleven ARP members provide On-Line Energy Audits. The Energy Depot Online Energy Audit also includes an energy calculator, Energy Library, and Energy Advisor which also allows customers to access information on appliances, windows, insulation, as well as additional energy tips and information.

In addition to the programs outlined below, ten ARP members participate in the ENERGY STAR® program as described in Section 17.1.7 of the Cane Island 4 Need for Power Application. Members can choose to participate in various ENERGY STAR® campaigns. This program helps members provide consumer education to their customers by:

- Placing links on their websites to the ENERGY STAR® homepage
- Displaying posters in their lobbies

- Providing promotional and educational material on ENERGY STAR® programs, appliances, conservation tools, and other features

Beaches Energy Services (Jacksonville Beach)

- Monthly newsletter
- Energy saving tips
- Work with local elementary schools
- TV public service announcements
- Newspaper
- Welcome bag: all new customers receive a bag with conservation material and a CFL bulb
- Bright Ideas Conservation Brochure
- Website
- Telephone on-hold messages
- Lobby educational videos
- CFL give-a-way programs

FPUA (Fort Pierce Utilities Authority)

- Provides energy tips brochures
- Provides water conservation brochures
- Online energy and water savings tips at their website
- Participated in radio shows featuring discussions regarding energy conservation
- Provided speakers for community & home owner's association events

Keys Energy Services (Utility Board of the City of Key West)

- Annual Energy Calendar Conservation Calendar/Contest
- National Children's Theater Energy Conservation Plays
- Tree giveaway educational brochure mailed to all customers
- Energy Conservation Radio Ads and bill inserts
- Hurricane safety radio ads and bill inserts
- Sponsorship of GLEE Film Festival and Expo
- Participation in local trade shows
- Website available 24/7

KUA (Kissimmee Utility Authority)

- Free Conservation Book: "The Case of the Rising Electric Bills"
- Online information in English & Spanish at KUA website
- Free Calendar of Energy Conservation
- Free CFL light bulbs
- Bill stuffer "energy informer newsletter" with every bill
- Free hurricane guides to cut power usage in a storm

- Sponsored over 250 community programs
- "Change a light changes the world" Energy Star campaign
- KUA Annual Report
- Kissimmee Main Street Garden Party – 250 trees donated
- Power plant tours
- Classroom presentations

Lake Worth

- Provides energy conservation tips in the "bill message" portion of monthly statements
- Mayor's energy conservation advisory committee

Ocala

- Monthly newsletter & bill stuffers mailed out with utility notices
- OEU website conservation information
- DOE Energy Star & Energy Depot Links
- Speakers Bureau
- Energy Audits

E. **Please explain or describe whether ARP members have any plans to expand the consumer education efforts of their DSM plans.**

Response: The ARP has formed a Conservation Program Task Force to review and recommend an ARP Conservation Program. The Task Force has developed a program for recommendation to the ARP Executive Committee that includes developing an Energy Tips brochure and a DVD of a residential energy audit.

The proposed Energy Tips brochure will be produced for all ARP members and made available to ARP member residential customers. The proposed DVD will include a walk through of a home with discussions of various energy saving tips, similar to what would be included in an "in person" residential energy audit. The ARP members plan to use the DVD in the following ways:

- Post the DVD on their websites

- Provide copies of the DVD to residential customers
- Broadcast the DVD on local public access television stations
- Broadcast the DVD in Customer Service Areas

In addition to this program, Fort Pierce plans to develop a conservation calendar with reminders and tips for homeowners. The calendars will be provided to new customers and during energy audits.

39. **Please refer to page 9, lines 1-4, of the direct testimony of Witness Rollins. Please identify or describe the projected water usage data. As part of this response, please include water use, quantity, source, and disposal method.**

Response: As stated in Section 9.1.8 of the Cane Island 4 Need for Power Application, a maximum of 3.0 million gallons per day (mgd) of reclaimed water from the Toho Water Authority is expected to be used for cooling tower makeup for Unit 4. Average cooling tower makeup is expected to be 2.4 – 2.5 mgd based on 24 hour per day operation. Additional water will be provided from existing on site wells plus one new well. This well water will serve as a backup supply for the cooling tower as well as service water, evaporative cooling tower makeup, potable water, and fire protection.

Water disposal method is described in Section 9.1.9 of the Cane Island 4 Need for Power Application. As stated in that section, there are five main sources of wastewater: sanitary waste, oil/water separator effluent, cooling tower blowdown, treated chemical wastewaters, and evaporative cooler blowdown. Sanitary waste will be routed to an

existing site septic system. Oil/water separator effluent will be directed to an onsite percolation pond. Other wastewaters, mostly cooling tower blowdown, will be returned to the Toho Water Authority pipeline. The movement of water through the plant can be seen in the Preliminary Water Mass Balance discussed below.

The Preliminary Water Mass Balance presented as Figure 9-2 on page 9-7 of the Cane Island 4 Need for Power Application provides more in depth information regarding the quantity of water used and where it will be routed. This figure is provided below for convenience.

For additional information regarding project water use please refer to the response to Interrogatory No. 5 of the Staff's First Set of Interrogatories.

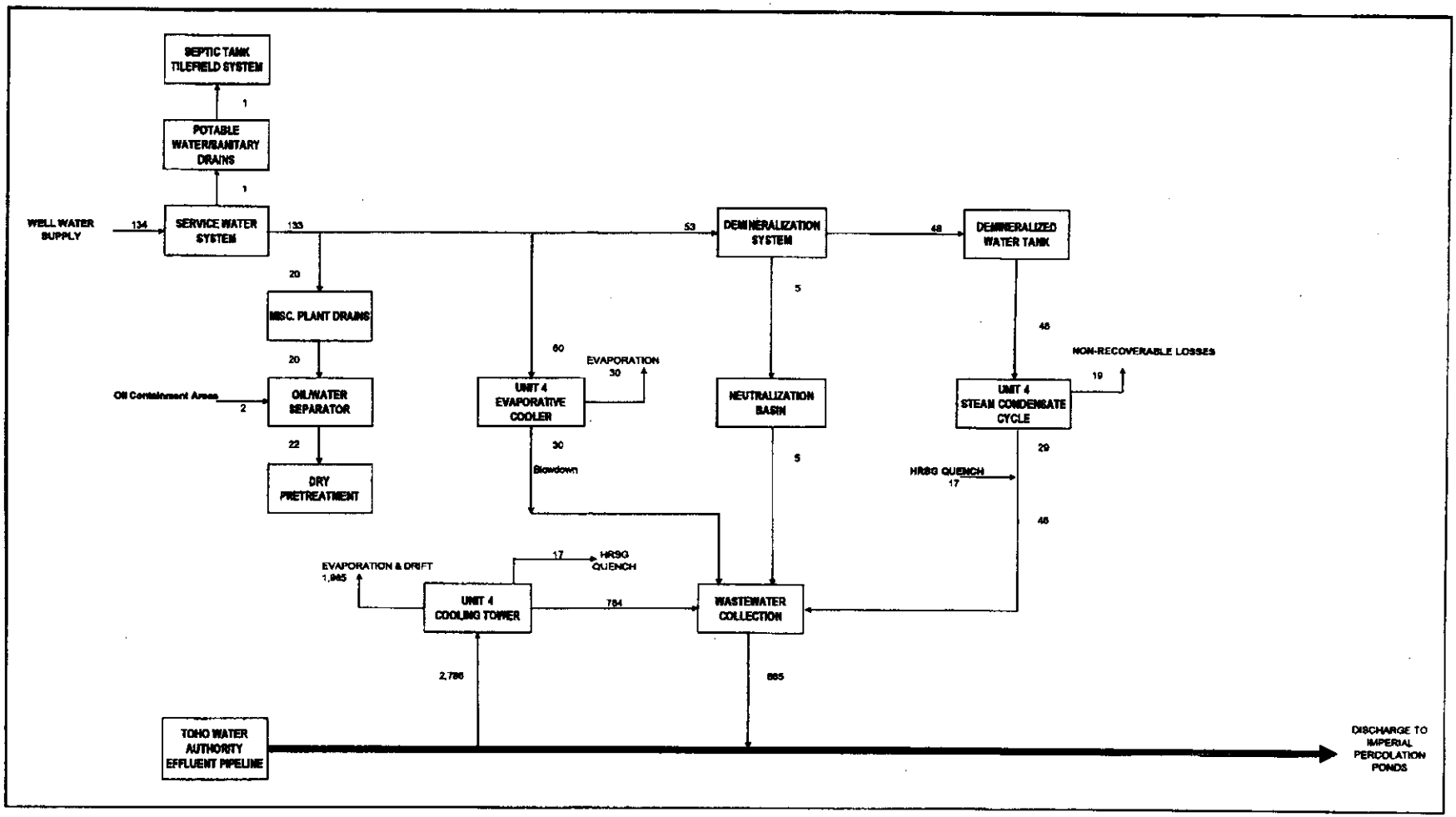


Figure 9-2
Preliminary Water Mass Balance

HEARING EXHIBIT - 00000062

40. Referring to page 14, lines 18-20, of the direct testimony of Witness Rollins, please respond to the following:

A. Please explain or describe why FMPA adheres to an 18 percent reserve margin in the summer.

Response: FMPA has chosen to adhere to an 18 percent minimum planned reserve margin for the summer in order to ensure that the summer peak demand, which usually has a much broader shape than a winter peak, will not result in brown out or black outs for the ARP member utilities.

B. Please explain or describe why FMPA adheres to a 15 percent reserve margin in the winter.

Response: FMPA has chosen to adhere to a 15 percent minimum planned reserve margin for the winter in order to ensure that the winter peak demand, which usually has a much narrower shape than a summer peak, will not result in a brown out or black out for the ARP member utilities.

C. Please explain or describe why interruptible load and curtailable load are not considered in setting the 18 percent reserve margin.

Response: Interruptible loads and curtailable loads are considered in setting the 18 percent reserve margin, but since there are not any interruptible or curtailable loads they do not affect the calculation.

D. Please explain or describe what the summer reserve margin would be for each year from 2010 to 2012 if interruptible load and curtailable load were used.

Response: The summer reserve margin for the years 2010 to 2012 would be identical to the one presented in the Cane Island 4 Need for Power Application since there are not any interruptible or curtailable loads to be considered.

41. **On page 10, lines 5-10, of his direct testimony, Witness Rollins discusses the $421.6 million capital cost for Cane Island Unit 4. Based on the 300 MW rated capacity of Cane Island Unit 4, this equates to a cost of ($421,600,000 / (300 MW x 1,000) =) $1,405 per kW. Please explain or describe why the Cane Island project will cost more than the concurrent Florida Power and Light petition proposing a natural gas unit at West County Energy Center for about $709 per kW (see Docket No. 080203).**

Response: Based upon review of the information that is available for Docket No. 080203, it is difficult to determine whether all project related costs have been included in the Florida Power & Light (FPL) West County Energy Center (WCEC) capital cost estimate to allow for a consistent comparison with the capital cost estimate of Cane Island 4. Recognizing that a detailed accounting of why the estimated capital costs per kW differ as indicated in Interrogatory No. 41 cannot therefore be provided, there are several factors that may contribute to and justify the differences noted. These factors include the following:

- Economies of scale in capital costs between a 300 MW unit (Cane Island 4) and a 1,219 MW unit (WCEC 3).
- Differences in scope between the two projects relative to existing onsite facilities already having sufficient capacity to accommodate the next unit.
- FPL's continuous construction of WCEC 3 in conjunction with WCEC 1 and WCEC 2 versus new construction mobilization for Cane Island 4.

- FMPA's payment to Kissimmee Utility Authority for its share of some of the common facilities of the existing Cane Island site that will be used for Cane Island 4.
- Differences in accounting for Owner's costs such as fuel costs during startup and testing, owner's project management costs, project contingency, operators during startup and testing, initial stocking of spare parts, and other miscellaneous costs.

42. **On page 11, lines 10-13, of this direct testimony, Witness Rollins testifies that Cane Island 4 will not be designed to operate on fuel oil as a backup source because the potential benefits are overshadowed by the incremental costs, maintenance, and limited reliability benefits. Please respond to the following:**

A. **Please explain or describe, in detail, the incremental costs, additive maintenance requirements, and limited reliability benefits of an oil backup capability.**

Response: The estimated capital cost for the addition of oil backup capability for Cane Island 4 were outlined in the Table 10-1 of the Cane Island 4 Need for Power Application. Table 10-1 is provided below for reference. The incremental capital cost associated with oil backup for Cane Island 4 is approximately $13 million.

Inclusion of oil backup capability for Cane Island 4 would necessitate additional operating and maintenance requirements, and their associated costs. The additional operating and maintenance requirements would be related to increased demineralized water usage when operating on fuel oil, costs associated with maintaining additional

equipment specific to the oil backup system, costs associated with test firing the fuel oil system to ensure it will perform reliably if called upon, increased wastewater disposal costs, and the potential for requiring replacement of a significant amount of fuel oil in the event the stored fuel oil deteriorates over time.

Deterioration of stored fuel oil is one of a number of limiting factors in the potential reliability associated with oil backup. Another concern related to reliability is the potential for increased forced outages due to the increased equipment required for oil backup and its associated complexity. Reliability of the oil backup system may also be adversely impacted by limitations in the availability of fuel oil in times of crises, as the ability of the existing infrastructure to deliver the required quantities of fuel oil may be overwhelmed.

Table 10-1 Cost to Add Liquid Fuel Firing for Cane Island 4	
Item	Estimated Cost, $
GE CTG Scope Addition	1,100,000
GE Scope Erection/BOP	370,000
Fuel Oil Storage Tanks, FP, and Berms	1,500,000
Fuel Oil Unloading	--
Fuel Oil Forwanding Skid	160,000
Piping and Electrical - Plant to Tanks	950,000
Demineralized Storage	1,250,000
Reverse Osmosis Unit	1,080,000
Water Treatment Building	230,000
False Start Drain Tank	50,000
Wastewater Additions	100,000
Demin Water Pumping	50,000
Service Water Pumping	50,000
EPC Contractor Markups	580,000
Startup and Commissioning Fuel Usage	2,500,000
Fill of Fuel Oil Tank for Commercial Operation	2,500,000
Interest and Bond Fees on Capital	560,000
Total	13,030,000

B. Please explain or describe FMPA's generation capability without oil backup if Florida were to experience a gas shortage like the one that occurred in the 2004-2005 hurricane season.

Response: During 2004, no fuel oil was burned at the Cane Island Site. During Hurricane Katrina on August 29, 2005 from 11:12 a.m. until 6:18 p.m., Cane Island Unit 1 burned 16,200 gallons of fuel oil because it was less expensive than natural gas. No other fuel oil was burned at the Cane Island site in 2005.

All of FMPA's natural gas generation has fuel oil back-up. When Cane Island 4 comes on line in 2011, it will comprise approximately 19.9 percent of FMPA's peak demand which is approximately equal to FMPA's minimum planned reserve margin of 18 percent in the summer. Since the Cane Island site is served by both Gulfstream and Florida Gas Transmission Company (FGT), there is a significant amount of geographic diversity of natural gas supply to the Cane Island site. If any natural gas for the four Cane Island units is available, it can be burned in Cane Island 4 and the other Cane Island units can be operated on fuel oil if necessary. FMPA's generating capability should remain reliable even with a natural gas shortage.

43. Please refer to page 17, lines 2-15, of Witness Guarriello's direct testimony. Please explain or describe whether the 44 MW implementation schedule shown on lines 8-15 is included in FMPA's load forecast.

Response: FMPA is currently evaluating a new DSM program that is projected to result in a 44 MW peak demand reduction by 2016. Reductions in load that may result from implementation of this program are not reflected in FMPA's load forecast. The DSM Expansion Scenario presented in Section 20 of the Cane Island 4 Need for Power Application (referred to as *Scenario 3 – DSM Expansion Scenario*) considers the load reductions associated with the DSM program being evaluated by FMPA, and the load forecast upon which this scenario is based does account for load reductions associated with the 44 MW implementation schedule.

45. On page 5, lines, 7-10, of his direct testimony Witness Guarriello testifies that FMPA has performed a thorough evaluation of reasonably available purchase power, renewable, and demand-side management alternatives to construction of Cane Island 4 in 2011. Please explain or describe the basis for this statement.

Response: Although not required to do so under the Commission's "Bid Rule," FMPA initiated four separate request for proposals (RFP) processes specifically intended to canvass the marketplace for conventional purchase power alternatives to Cane Island

4, renewable capacity and energy, solar photovoltaic equipment or power purchases, and demand-side management resources. These RFP processes offered qualified companies the opportunity to provide purchase power, renewable, and demand-side management alternatives to construction of Cane Island 4 in 2011.

No bidders responded to the power supply RFP, and evaluation of the bids received in response to the renewable and demand-side management RFPs demonstrate that construction of Cane Island 4 in 2011 is the most cost effective alternative available to FMPA. The analysis performed in Scenarios 2, 3, and 4 as discussed in Section 20 of the Cane Island 4 Need for Power Application indicate that the addition of Cane Island 4 in 2011 in combination with the renewable proposals and the demand-side management proposals is more economic than implementation of the renewable and demand-side management proposals as an alternative to Cane Island 4 in 2011.

46. On page 19, lines 19-21 of the direct testimony of Witness Guarriello, he testifies that the least cost expansion plan with Cane Island Unit 4 would enable FMPA to achieve the 2017 CO_2 emission target level in Executive Order 07-127. Please respond to the following:

A. Please identify or describe FMPA's projected 2017 CO_2 emission level.

Response: Expected emissions of CO_2 associated with serving the forecast energy requirements of FMPA's All-Requirements Power Supply Project (ARP) in 2017 are estimated to be approximately 3,946,000 tons for the Reference Case presented in Section 20.0 of the Cane Island 4 Need for Power Application.

B. Please identify or describe the target level for emissions level set by Executive Order 07-127.

Response: Governor Crist's Executive Order 07-127 sets goals for utilities to reduce their greenhouse gas emissions to year 2000 levels by 2017. Using the methodology discussed in Section 18 of the Cane Island 4 Need for Power Application, the actual historical emissions of CO_2 resulting from serving the requirements of the 15 current ARP members (including the City of Vero Beach) in 2000 were approximately 4,707,000 tons. By 2017, FMPA will only serve a relatively small portion of the City of Vero Beach's projected energy requirements. If the year 2000 CO_2 emissions were adjusted to remove emissions associated with the City of Vero Beach, the 200 baseline CO_2 would be approximately 4,180,000 tons.

49. Please refer to Exhibit BEK-5, attached to the direct testimony of Witness Kushner. Please complete the following table (also provided in Excel format) in electronic (Excel) and hard copy showing cumulative costs for the period 2007-2027.

Response: Please refer to the attached tables, included in Attachment 49 and also presented in electronic format on the enclosed CD. For all of the tables included in Attachment 49, the Environmental Costs include allowance costs for SO_2 and NO_x, and for CO_2 where appropriate. Other Costs include purchase power costs, fixed and variable O&M costs, and incremental firm natural gas transportation costs.

50. Please complete the tables below (also provided in Excel format) in electronic (Excel) and hard copy showing a Reserve Margin analysis of the following:

A. Please identify or describe FMPA's summer reserve capacity with Cane Island Unit 4;

B. Please identify or describe FMPA's summer reserve capacity without Cane Island Unit 4;

C. Please identify or describe FMPA's winter reserve capacity with Cane Island Unit 4; and

D. Please identify or describe FMPA's winter reserve capacity without Cane Island Unit 4.

Response:

Please refer to the attached tables, included in Attachment 50 and also presented in electronic format on the enclosed CD. For Tables 50.A through 50.D, an additional column has been added indicating the reserve margin taking into consideration partial

requirements purchases, which include reserves. Data for 2007 is not presented since the analyses included Cane Island 4 Need for Power Application begins in 2008.

- Table 50.A - "Reserve Margin Analysis with Cane Island 4: Summer"
- Table 50.B - "Reserve Margin Analysis without Cane Island 4: Summer"
- Table 50.C - "Reserve Margin Analysis with Cane Island 4: Winter"
- Table 50.D - "Reserve Margin Analysis without Cane Island 4: Winter"

Responses to Nos. 30, 33, 34, 35, 36, 37, and 38 of Staff's Fourth Set of Interrogatories (Nos. 30-50)were provided by Thomas Reedy, Assistant General Manager of the Power Resources Division, Florida Municipal Power Agency, 8553 Commodity Circle, Orlando, Florida 32819.

Responses to Nos. 31, 39, 40, 41, and 42 of Staff's Fourth Set of Interrogatories (Nos. 30-50) were provided by Myron Rollins (consultant to FMPA), Black & Veatch Corporation, 11401 Lamar Avenue, Overland Park, Kansas 66211.

Responses to Nos. 32, 43, 47, 48, 49, and 50 of Staff's Fourth Set of Interrogatories (Nos. 30-50) were provided by Bradley Kushner (consultant to FMPA), Black & Veatch Corporation, 11401 Lamar Avenue, Overland Park, Kansas 66211.

Responses to Nos. 44, 45, and 46 of Staff's Fourth Set of Interrogatories (Nos. 30-50) were provided by Nicholas Guarriello (consultant to FMPA), R.W. Beck, 1000 Legion Place, Suite 1100, Orlando, Florida 32801.

Dated this 10th day of July, 2008.

HOPPING GREEN & SAMS, P.A.

Gary V. Perko
Hopping Green & Sams, P.A.
123 S. Calhoun Street
Tallahassee, FL 32314
(850) 222-7500 (telephone)
(850) 224-8551 (facsimile)
Email: GPerko@hgslaw.com

Attorney for Florida Municipal Power Agency

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing FMPA's Response to the Florida Public Service Commission STAFF'S FOURTH SET OF INTERROGATORIES (NOS. 30 - 50) has been served by hand delivery to the following on this 10th day of July, 2008:

Katherine Fleming
Senior Attorney
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, Florida 32399-0850

Attorney

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF ORANGE)

I hereby certify that on this 9th day of July, 2008, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Thomas Reedy, who is personally known to me, and he/she acknowledged before me that he/she provided the answers to interrogatory numbers 30, 33, 34, 35, 36, 37, and 38 from STAFF'S FOURTH SET OF INTERROGATORIES TO FLORIDA MUNICIPAL POWER AGENCY (NOS. 30-50) in Docket No. 080253-EM, and that the responses are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 9th day of July, 2008.

Notary Public
State of Florida, at large
Donna Sue Utley
My Commission Expires:
7-10-09

Tom Reedy

Tom Reedy
Asst. General Mgr., Power Resources

DONNA SUE UTLEY
Comm# DD0449073
Expires 7/10/2009
Bonded thru (800)432-4254
Florida Notary Assn., Inc

AFFIDAVIT

STATE OF KANSAS)

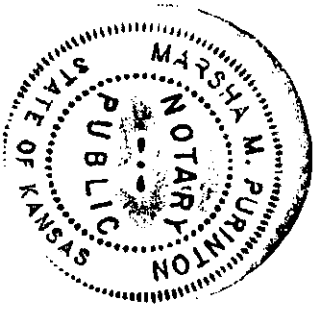
COUNTY OF JOHNSON)

I hereby certify that on this 8th day of July, 2008, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Myron R. Rollins, who is personally known to me, and he/she acknowledged before me that he/she provided the answers to interrogatory numbers 31, 39, 40, 41, and 42 from STAFF'S FOURTH SET OF INTERROGATORIES TO FLORIDA MUNICIPAL POWER AGENCY (NOS. 30-50) in Docket No. 080253-EM, and that the responses are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 8th day of July, 2008.

Myron Rollins

Notary Public
State of Kansas, at large
Marsha Purinton
My Commission Expires:
7-30-2011



AFFIDAVIT

STATE OF KANSAS)

COUNTY OF JOHNSON)

I hereby certify that on this 8th day of July, 2008, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Bradley Kushner, who is personally known to me, and he/she acknowledged before me that he/she provided the answers to interrogatory numbers 32, 43, 47, 48, 49, and 50 from STAFF'S FOURTH SET OF INTERROGATORIES TO FLORIDA MUNICIPAL POWER AGENCY (NOS. 30-50) in Docket No. 080253-EM, and that the responses are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 8th day of July, 2008.

Notary Public
State of Kansas, at large
Marsha Purinton
My Commission Expires:
7-30-2011

MARSHA M. PURINTON NOTARY PUBLIC STATE OF KANSAS

AFFIDAVIT

STATE OF KANSAS)

COUNTY OF JOHNSON)

I hereby certify that on this 9th day of July, 2008, before me, an officer duly authorized in the State and County ~~aforesaid~~ below to take acknowledgments, personally appeared Nicholas Guarriello, who is personally known to me, and he/she acknowledged before me that he/she provided the answers to interrogatory numbers 44, 45, and 46 from STAFF'S FOURTH SET OF INTERROGATORIES TO FLORIDA MUNICIPAL POWER AGENCY (NOS. 30-50) in Docket No. 080253-EM, and that the responses are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 9th day of July, 2008.

Nicholas Guarriello

Notary Public
State of ~~Kansas~~ Florida, at large

My Commission Expires:

Thaddeus Szymankiewicz

Notary Public State of Florida
Thaddeus Szymankiewicz
My Commission DD541922
Expires 06/30/2010

Attachment 31B

FMPA's Response to the Staff's 4th Set of Interrogatories

Table 31.B.1 - Only Lake Worth 3 Retired
Projected Reliability Levels - Summer/Base Case - No new additions after TCEC

Year	Net Generating Capacity (MW)	Non-Partial Requirements Purchases (MW)	Partial Requirements Purchases (MW)	Net Firm Planned Capacity Retirements [1] (MW)	Net Firm Capacity Additions [2] (MW)	Net System Capacity (MW)	System Peak Demand [3]	Reserve Margin [4]	Excess/(Deficit) to Maintain 18% Reserve Margin
2008	1,318	337	75	(114)	296	1,912	1,545	25.0%	103
2009	1,318	337	120	(114)	296	1,957	1,593	24.7%	98
2010	1,318	237	165	(300)	296	1,717	1,483	17.7%	(3)
2011	1,318	237	45	(324)	296	1,572	1,527	3.0%	(222)
2012	1,318	237	45	(315)	296	1,581	1,560	1.4%	(252)
2013	1,318	237	0	(315)	296	1,536	1,594	-3.7%	(345)
2014	1,318	237	0	(315)	296	1,536	1,630	-5.8%	(387)
2015	1,318	237	0	(315)	296	1,536	1,668	-7.9%	(431)
2016	1,318	237	0	(315)	296	1,536	1,705	-9.9%	(476)
2017	1,318	237	0	(315)	296	1,536	1,744	-11.9%	(521)
2018	1,318	237	0	(315)	296	1,536	1,782	-13.8%	(566)
2019	1,318	237	0	(315)	296	1,536	1,820	-15.6%	(611)
2020	1,318	237	0	(315)	296	1,536	1,859	-17.3%	(657)
2021	1,318	237	0	(315)	296	1,536	1,898	-19.0%	(703)
2022	1,318	237	0	(315)	296	1,536	1,938	-20.7%	(750)
2023	1,318	237	0	(315)	296	1,536	1,978	-22.3%	(797)
2024	1,318	237	0	(315)	296	1,536	2,018	-23.8%	(844)
2025	1,318	237	0	(315)	296	1,536	2,057	-25.3%	(891)
2026	1,318	237	0	(315)	296	1,536	2,098	-26.8%	(939)
2027	1,318	237	0	(315)	296	1,536	2,139	-28.2%	(987)

[1] Includes changes to the ratings of existing nuclear generating resources and the loss of City of Vero Beach generating units associated with CROD

[2] Firm capacity additions include Treasure Coast Energy Center Unit 1 Combined Cycle (2008)

[3] City of Vero Beach's forecast capacity requirements are no longer included beginning January 1, 2010, when the CROD becomes effective, except for approximately 21 MW (summer requirement) of the City of Vero Beach's load resulting from CROD

[4] Reserve margin calculated as (Net System Capacity - Partial Requirements Purchases) - (System Peak Demand - Partial Requirements Purchases) / (System Peak Demand - Partial Requirements Purchases).

HEARING EXHIBIT - 00000080

Table 31.B.2 - Only Lake Worth Unit 5 Retired
Projected Reliability Levels - Summer/Base Case - No new additions after TCEC

Year	Net Generating Capacity (MW)	Non-Partial Requirements Purchases (MW)	Partial Requirements Purchases (MW)	Net Firm Planned Capacity Retirements [1] (MW)	Net Firm Capacity Additions [2] (MW)	Net System Capacity (MW)	System Peak Demand [3]	Reserve Margin [4]	Excess/(Deficit) to Maintain 18% Reserve Margin
2008	1,318	337	75	(114)	296	1,912	1,545	25.0%	103
2009	1,318	337	120	(114)	296	1,957	1,593	24.7%	98
2010	1,318	237	165	(300)	296	1,717	1,483	17.7%	(3)
2011	1,318	237	45	(307)	296	1,589	1,527	4.2%	(205)
2012	1,318	237	45	(298)	296	1,598	1,560	2.5%	(235)
2013	1,318	237	0	(298)	296	1,553	1,594	-2.6%	(328)
2014	1,318	237	0	(298)	296	1,553	1,630	-4.7%	(370)
2015	1,318	237	0	(298)	296	1,553	1,668	-6.8%	(414)
2016	1,318	237	0	(298)	296	1,553	1,705	-8.9%	(459)
2017	1,318	237	0	(298)	296	1,553	1,744	-10.9%	(504)
2018	1,318	237	0	(298)	296	1,553	1,782	-12.8%	(549)
2019	1,318	237	0	(298)	296	1,553	1,820	-14.6%	(594)
2020	1,318	237	0	(298)	296	1,553	1,859	-16.4%	(640)
2021	1,318	237	0	(298)	296	1,553	1,898	-18.1%	(686)
2022	1,318	237	0	(298)	296	1,553	1,938	-19.8%	(733)
2023	1,318	237	0	(298)	296	1,553	1,978	-21.4%	(780)
2024	1,318	237	0	(298)	296	1,553	2,018	-23.0%	(827)
2025	1,318	237	0	(298)	296	1,553	2,057	-24.5%	(874)
2026	1,318	237	0	(298)	296	1,553	2,098	-25.9%	(922)
2027	1,318	237	0	(298)	296	1,553	2,139	-27.4%	(970)

[1] Includes changes to the ratings of existing nuclear generating resources and the loss of City of Vero Beach generating units associated with CROD

[2] Firm capacity additions include Treasure Coast Energy Center Unit 1 Combined Cycle (2008)

[3] City of Vero Beach's forecast capacity requirements are no longer included beginning January 1, 2010, when the CROD becomes effective, except for approximately 21 MW (summer requirement) of the City of Vero Beach's load resulting from CROD

[4] Reserve margin caluclated as (Net System Capacity - Partial Requirements Purchases) - (System Peak Demand - Partial Requirements Purchases) / (System Peak Demand - Partial Requirements Purchases).

HEARING EXHIBIT - 00000081

Table 31.B.3 - Only Lake Worth GT1 Retired
Projected Reliability Levels - Summer/Base Case - No new additions after TCEC

Year	Net Generating Capacity (MW)	Non-Partial Requirements Purchases (MW)	Partial Requirements Purchases (MW)	Net Firm Planned Capacity Retirements [1] (MW)	Net Firm Capacity Additions [2] (MW)	Net System Capacity (MW)	System Peak Demand [3]	Reserve Margin [4]	Excess/(Deficit) to Maintain 18% Reserve Margin
2008	1,318	337	75	(114)	296	1,912	1,545	25.0%	103
2009	1,318	337	120	(114)	296	1,957	1,593	24.7%	98
2010	1,318	237	165	(300)	296	1,717	1,483	17.7%	(3)
2011	1,318	237	45	(326)	296	1,570	1,527	2.9%	(224)
2012	1,318	237	45	(317)	296	1,579	1,560	1.3%	(254)
2013	1,318	237	0	(317)	296	1,534	1,594	-3.8%	(347)
2014	1,318	237	0	(317)	296	1,534	1,630	-5.9%	(389)
2015	1,318	237	0	(317)	296	1,534	1,668	-8.0%	(433)
2016	1,318	237	0	(317)	296	1,534	1,705	-10.0%	(478)
2017	1,318	237	0	(317)	296	1,534	1,744	-12.0%	(523)
2018	1,318	237	0	(317)	296	1,534	1,782	-13.9%	(568)
2019	1,318	237	0	(317)	296	1,534	1,820	-15.7%	(613)
2020	1,318	237	0	(317)	296	1,534	1,859	-17.4%	(659)
2021	1,318	237	0	(317)	296	1,534	1,898	-19.2%	(705)
2022	1,318	237	0	(317)	296	1,534	1,938	-20.8%	(752)
2023	1,318	237	0	(317)	296	1,534	1,978	-22.4%	(799)
2024	1,318	237	0	(317)	296	1,534	2,018	-23.9%	(846)
2025	1,318	237	0	(317)	296	1,534	2,057	-25.4%	(893)
2026	1,318	237	0	(317)	296	1,534	2,098	-26.9%	(941)
2027	1,318	237	0	(317)	296	1,534	2,139	-28.3%	(989)

[1] Includes changes to the ratings of existing nuclear generating resources and the loss of City of Vero Beach generating units associated with CROD

[2] Firm capacity additions include Treasure Coast Energy Center Unit 1 Combined Cycle (2008)

[3] City of Vero Beach's forecast capacity requirements are no longer included beginning January 1, 2010, when the CROD becomes effective, except for approximately 21 MW (summer requirement) of the City of Vero Beach's load resulting from CROD

[4] Reserve margin calculated as (Net System Capacity - Partial Requirements Purchases) - (System Peak Demand - Partial Requirements Purchases) / (System Peak Demand - Partial Requirements Purchases).

HEARING EXHIBIT - 00000082

Table 31.B.4 - Only Lake Worth GT2 Retired
Projected Reliability Levels - Summer/Base Case - No new additions after TCEC

Year	Net Generating Capacity (MW)	Non-Partial Requirements Purchases (MW)	Partial Requirements Purchases (MW)	Net Firm Planned Capacity Retirements [1] (MW)	Net Firm Capacity Additions [2] (MW)	Net System Capacity (MW)	System Peak Demand [3]	Reserve Margin [4]	Excess/(Deficit) to Maintain 18% Reserve Margin
2008	1,318	337	75	(114)	296	1,912	1,545	25.0%	103
2009	1,318	337	120	(114)	296	1,957	1,593	24.7%	98
2010	1,318	237	165	(300)	296	1,717	1,483	17.7%	(3)
2011	1,318	237	45	(319)	296	1,577	1,527	3.4%	(217)
2012	1,318	237	45	(310)	296	1,586	1,560	1.7%	(247)
2013	1,318	237	0	(310)	296	1,541	1,594	-3.4%	(340)
2014	1,318	237	0	(310)	296	1,541	1,630	-5.5%	(382)
2015	1,318	237	0	(310)	296	1,541	1,668	-7.6%	(426)
2016	1,318	237	0	(310)	296	1,541	1,705	-9.6%	(471)
2017	1,318	237	0	(310)	296	1,541	1,744	-11.6%	(516)
2018	1,318	237	0	(310)	296	1,541	1,782	-13.5%	(561)
2019	1,318	237	0	(310)	296	1,541	1,820	-15.3%	(606)
2020	1,318	237	0	(310)	296	1,541	1,859	-17.1%	(652)
2021	1,318	237	0	(310)	296	1,541	1,898	-18.8%	(698)
2022	1,318	237	0	(310)	296	1,541	1,938	-20.4%	(745)
2023	1,318	237	0	(310)	296	1,541	1,978	-22.1%	(792)
2024	1,318	237	0	(310)	296	1,541	2,018	-23.6%	(839)
2025	1,318	237	0	(310)	296	1,541	2,057	-25.1%	(886)
2026	1,318	237	0	(310)	296	1,541	2,098	-26.5%	(934)
2027	1,318	237	0	(310)	296	1,541	2,139	-27.9%	(982)

[1] Includes changes to the ratings of existing nuclear generating resources and the loss of City of Vero Beach generating units associated with CROD

[2] Firm capacity additions include Treasure Coast Energy Center Unit 1 Combined Cycle (2008)

[3] City of Vero Beach's forecast capacity requirements are no longer included beginning January 1, 2010, when the CROD becomes effective, except for approximately 21 MW (summer requirement) of the City of Vero Beach's load resulting from CROD

[4] Reserve margin caluclated as (Net System Capacity - Partial Requirements Purchases) - (System Peak Demand - Partial Requirements Purchases) / (System Peak Demand - Partial Requirements Purchases).

HEARING EXHIBIT - 00000083

Table 31.B.5 - Only Lake Worth D1-5 Retired
Projected Reliability Levels - Summer/Base Case - No new additions after TCEC

Year	Net Generating Capacity (MW)	Non-Partial Requirements Purchases (MW)	Partial Requirements Purchases (MW)	Net Firm Planned Capacity Retirements [1] (MW)	Net Firm Capacity Additions [2] (MW)	Net System Capacity (MW)	System Peak Demand [3]	Reserve Margin [4]	Excess/(Deficit) to Maintain 18% Reserve Margin
2008	1,318	337	75	(114)	296	1,912	1,545	25.0%	103
2009	1,318	337	120	(114)	296	1,957	1,593	24.7%	98
2010	1,318	237	165	(300)	296	1,717	1,483	17.7%	(3)
2011	1,318	237	45	(309)	296	1,587	1,527	4.1%	(207)
2012	1,318	237	45	(300)	296	1,596	1,560	2.4%	(237)
2013	1,318	237	0	(300)	296	1,551	1,594	-2.7%	(330)
2014	1,318	237	0	(300)	296	1,551	1,630	-4.8%	(372)
2015	1,318	237	0	(300)	296	1,551	1,668	-7.0%	(416)
2016	1,318	237	0	(300)	296	1,551	1,705	-9.0%	(461)
2017	1,318	237	0	(300)	296	1,551	1,744	-11.0%	(506)
2018	1,318	237	0	(300)	296	1,551	1,782	-12.9%	(551)
2019	1,318	237	0	(300)	296	1,551	1,820	-14.7%	(596)
2020	1,318	237	0	(300)	296	1,551	1,859	-16.5%	(642)
2021	1,318	237	0	(300)	296	1,551	1,898	-18.3%	(688)
2022	1,318	237	0	(300)	296	1,551	1,938	-19.9%	(735)
2023	1,318	237	0	(300)	296	1,551	1,978	-21.5%	(782)
2024	1,318	237	0	(300)	296	1,551	2,018	-23.1%	(829)
2025	1,318	237	0	(300)	296	1,551	2,057	-24.6%	(876)
2026	1,318	237	0	(300)	296	1,551	2,098	-26.0%	(924)
2027	1,318	237	0	(300)	296	1,551	2,139	-27.5%	(972)

[1] Includes changes to the ratings of existing nuclear generating resources and the loss of City of Vero Beach generating units associated with CROD

[2] Firm capacity additions include Treasure Coast Energy Center Unit 1 Combined Cycle (2008)

[3] City of Vero Beach's forecast capacity requirements are no longer included beginning January 1, 2010, when the CROD becomes effective, except for approximately 21 MW (summer requirement) of the City of Vero Beach's load resulting from CROD

[4] Reserve margin caluclated as (Net System Capacity - Partial Requirements Purchases) - (System Peak Demand - Partial Requirements Purchases) / (System Peak Demand - Partial Requirements Purchases).

HEARING EXHIBIT - 00000084

Table 31.B.6 - Only Hansel Combined Cycle Retired
Projected Reliability Levels - Summer/Base Case - No new additions after TCEC

Year	Net Generating Capacity (MW)	Non-Partial Requirements Purchases (MW)	Partial Requirements Purchases (MW)	Net Firm Planned Capacity Retirements [1] (MW)	Net Firm Capacity Additions [2] (MW)	Net System Capacity (MW)	System Peak Demand [3]	Reserve Margin [4]	Excess/(Deficit) to Maintain 18% Reserve Margin
2008	1,318	337	75	(114)	296	1,912	1,545	25.0%	103
2009	1,318	337	120	(114)	296	1,957	1,593	24.7%	98
2010	1,318	237	165	(300)	296	1,717	1,483	17.7%	(3)
2011	1,318	237	45	(299)	296	1,597	1,527	4.7%	(197)
2012	1,318	237	45	(336)	296	1,559	1,560	0.0%	(273)
2013	1,318	237	0	(336)	296	1,514	1,594	-5.0%	(367)
2014	1,318	237	0	(336)	296	1,515	1,630	-7.1%	(409)
2015	1,318	237	0	(336)	296	1,515	1,668	-9.2%	(453)
2016	1,318	237	0	(336)	296	1,515	1,705	-11.2%	(498)
2017	1,318	237	0	(336)	296	1,515	1,744	-13.1%	(543)
2018	1,318	237	0	(336)	296	1,515	1,782	-15.0%	(587)
2019	1,318	237	0	(336)	296	1,515	1,820	-16.8%	(633)
2020	1,318	237	0	(336)	296	1,515	1,859	-18.5%	(678)
2021	1,318	237	0	(336)	296	1,515	1,898	-20.2%	(725)
2022	1,318	237	0	(336)	296	1,515	1,938	-21.8%	(772)
2023	1,318	237	0	(336)	296	1,515	1,978	-23.4%	(819)
2024	1,318	237	0	(336)	296	1,515	2,018	-24.9%	(866)
2025	1,318	237	0	(336)	296	1,515	2,057	-26.4%	(913)
2026	1,318	237	0	(336)	296	1,515	2,098	-27.8%	(961)
2027	1,318	237	0	(336)	296	1,515	2,139	-29.2%	(1,009)

[1] Includes changes to the ratings of existing nuclear generating resources and the loss of City of Vero Beach generating units associated with CROD

[2] Firm capacity additions include Treasure Coast Energy Center Unit 1 Combined Cycle (2008)

[3] City of Vero Beach's forecast capacity requirements are no longer included beginning January 1, 2010, when the CROD becomes effective, except for approximately 21 MW (summer requirement) of the City of Vero Beach's load resulting from CROD

[4] Reserve margin caluclated as (Net System Capacity - Partial Requirements Purchases) - (System Peak Demand - Partial Requirements Purchases) / (System Peak Demand - Partial Requirements Purchases).

HEARING EXHIBIT - 00000085

Attachment 31C

FMPA's Response to the Staff's 4th Set of Interrogatories

Table 31.C.1 - Lake Worth Unit 3 & Lake Worth Unit 5 Retired
Projected Reliability Levels - Summer/Base Case - No new additions after TCEC

Year	Net Generating Capacity (MW)	Non-Partial Requirements Purchases (MW)	Partial Requirements Purchases (MW)	Net Firm Planned Capacity Retirements [1] (MW)	Net Firm Capacity Additions [2] (MW)	Net System Capacity (MW)	System Peak Demand [3]	Reserve Margin [4]	Excess/(Deficit) to Maintain 18% Reserve Margin
2008	1,318	337	75	(114)	296	1,912	1,545	25.0%	103
2009	1,318	337	120	(114)	296	1,957	1,593	24.7%	98
2010	1,318	237	165	(300)	296	1,717	1,483	17.7%	(3)
2011	1,318	237	45	(332)	296	1,564	1,527	2.5%	(230)
2012	1,318	237	45	(322)	296	1,573	1,560	0.9%	(259)
2013	1,318	237	0	(322)	296	1,528	1,594	-4.1%	(353)
2014	1,318	237	0	(322)	296	1,529	1,630	-6.2%	(395)
2015	1,318	237	0	(322)	296	1,529	1,668	-8.3%	(439)
2016	1,318	237	0	(322)	296	1,529	1,705	-10.4%	(484)
2017	1,318	237	0	(322)	296	1,529	1,744	-12.3%	(529)
2018	1,318	237	0	(322)	296	1,529	1,782	-14.2%	(573)
2019	1,318	237	0	(322)	296	1,529	1,820	-16.0%	(619)
2020	1,318	237	0	(322)	296	1,529	1,859	-17.7%	(664)
2021	1,318	237	0	(322)	296	1,529	1,898	-19.5%	(711)
2022	1,318	237	0	(322)	296	1,529	1,938	-21.1%	(758)
2023	1,318	237	0	(322)	296	1,529	1,978	-22.7%	(805)
2024	1,318	237	0	(322)	296	1,529	2,018	-24.2%	(852)
2025	1,318	237	0	(322)	296	1,529	2,057	-25.7%	(899)
2026	1,318	237	0	(322)	296	1,529	2,098	-27.1%	(947)
2027	1,318	237	0	(322)	296	1,529	2,139	-28.5%	(995)

[1] Includes changes to the ratings of existing nuclear generating resources and the loss of City of Vero Beach generating units associated with CROD

[2] Firm capacity additions include Treasure Coast Energy Center Unit 1 Combined Cycle (2008)

[3] City of Vero Beach's forecast capacity requirements are no longer included beginning January 1, 2010, when the CROD becomes effective, except for approximately 21 MW (summer requirement) of the City of Vero Beach's load resulting from CROD

[4] Reserve margin caluclated as (Net System Capacity - Partial Requirements Purchases) - (System Peak Demand - Partial Requirements Purchases) / (System Peak Demand - Partial Requirements Purchases).

HEARING EXHIBIT - 00000087

Table 31.C.2 - Lake Worth Unit 3 & Lake Worth GT1 Retired
Projected Reliability Levels - Summer/Base Case - No new additions after TCEC

Year	Net Generating Capacity (MW)	Non-Partial Requirements Purchases (MW)	Partial Requirements Purchases (MW)	Net Firm Planned Capacity Retirements [1] (MW)	Net Firm Capacity Additions [2] (MW)	Net System Capacity (MW)	System Peak Demand [3]	Reserve Margin [4]	Excess/(Deficit) to Maintain 18% Reserve Margin
2008	1,318	337	75	(114)	296	1,912	1,545	25.0%	103
2009	1,318	337	120	(114)	296	1,957	1,593	24.7%	98
2010	1,318	237	165	(300)	296	1,717	1,483	17.7%	(3)
2011	1,318	237	45	(351)	296	1,545	1,527	1.2%	(249)
2012	1,318	237	45	(342)	296	1,554	1,560	-0.4%	(279)
2013	1,318	237	0	(342)	296	1,509	1,594	-5.4%	(372)
2014	1,318	237	0	(342)	296	1,509	1,630	-7.4%	(414)
2015	1,318	237	0	(342)	296	1,509	1,668	-9.5%	(458)
2016	1,318	237	0	(342)	296	1,509	1,705	-11.5%	(503)
2017	1,318	237	0	(342)	296	1,509	1,744	-13.4%	(548)
2018	1,318	237	0	(342)	296	1,509	1,782	-15.3%	(593)
2019	1,318	237	0	(342)	296	1,509	1,820	-17.1%	(638)
2020	1,318	237	0	(342)	296	1,509	1,859	-18.8%	(684)
2021	1,318	237	0	(342)	296	1,509	1,898	-20.5%	(730)
2022	1,318	237	0	(342)	296	1,509	1,938	-22.1%	(777)
2023	1,318	237	0	(342)	296	1,509	1,978	-23.7%	(824)
2024	1,318	237	0	(342)	296	1,509	2,018	-25.2%	(871)
2025	1,318	237	0	(342)	296	1,509	2,057	-26.6%	(918)
2026	1,318	237	0	(342)	296	1,509	2,098	-28.0%	(966)
2027	1,318	237	0	(342)	296	1,509	2,139	-29.4%	(1,014)

[1] Includes changes to the ratings of existing nuclear generating resources and the loss of City of Vero Beach generating units associated with CROD

[2] Firm capacity additions include Treasure Coast Energy Center Unit 1 Combined Cycle (2008)

[3] City of Vero Beach's forecast capacity requirements are no longer included beginning January 1, 2010, when the CROD becomes effective, except for approximately 21 MW (summer requirement) of the City of Vero Beach's load resulting from CROD

[4] Reserve margin caluclated as (Net System Capacity - Partial Requirements Purchases) - (System Peak Demand - Partial Requirements Purchases) / (System Peak Demand - Partial Requirements Purchases).

HEARING EXHIBIT - 00000088

Table 31.C.3 - Lake Worth Unit 3 & Lake Worth GT2 Retired
Projected Reliability Levels - Summer/Base Case - No new additions after TCEC

Year	Net Generating Capacity (MW)	Non-Partial Requirements Purchases (MW)	Partial Requirements Purchases (MW)	Net Firm Planned Capacity Retirements [1] (MW)	Net Firm Capacity Additions [2] (MW)	Net System Capacity (MW)	System Peak Demand [3]	Reserve Margin [4]	Excess/(Deficit) to Maintain 18% Reserve Margin
2008	1,318	337	75	(114)	296	1,912	1,545	25.0%	103
2009	1,318	337	120	(114)	296	1,957	1,593	24.7%	98
2010	1,318	237	165	(300)	296	1,717	1,483	17.7%	(3)
2011	1,318	237	45	(344)	296	1,552	1,527	1.7%	(242)
2012	1,318	237	45	(334)	296	1,561	1,560	0.1%	(271)
2013	1,318	237	0	(334)	296	1,516	1,594	-4.9%	(365)
2014	1,318	237	0	(334)	296	1,517	1,630	-7.0%	(407)
2015	1,318	237	0	(334)	296	1,517	1,668	-9.0%	(451)
2016	1,318	237	0	(334)	296	1,517	1,705	-11.1%	(496)
2017	1,318	237	0	(334)	296	1,517	1,744	-13.0%	(541)
2018	1,318	237	0	(334)	296	1,517	1,782	-14.9%	(585)
2019	1,318	237	0	(334)	296	1,517	1,820	-16.7%	(631)
2020	1,318	237	0	(334)	296	1,517	1,859	-18.4%	(676)
2021	1,318	237	0	(334)	296	1,517	1,898	-20.1%	(723)
2022	1,318	237	0	(334)	296	1,517	1,938	-21.7%	(770)
2023	1,318	237	0	(334)	296	1,517	1,978	-23.3%	(817)
2024	1,318	237	0	(334)	296	1,517	2,018	-24.8%	(864)
2025	1,318	237	0	(334)	296	1,517	2,057	-26.3%	(911)
2026	1,318	237	0	(334)	296	1,517	2,098	-27.7%	(959)
2027	1,318	237	0	(334)	296	1,517	2,139	-29.1%	(1,007)

[1] Includes changes to the ratings of existing nuclear generating resources and the loss of City of Vero Beach generating units associated with CROD

[2] Firm capacity additions include Treasure Coast Energy Center Unit 1 Combined Cycle (2008)

[3] City of Vero Beach's forecast capacity requirements are no longer included beginning January 1, 2010, when the CROD becomes effective, except for approximately 21 MW (summer requirement) of the City of Vero Beach's load resulting from CROD

[4] Reserve margin caluclated as (Net System Capacity - Partial Requirements Purchases) - (System Peak Demand - Partial Requirements Purchases) / (System Peak Demand - Partial Requirements Purchases).

HEARING EXHIBIT - 00000089

Table 31.C.4 - Lake Worth Unit 3 & Lake Worth D1-5 Retired
Projected Reliability Levels - Summer/Base Case - No new additions after TCEC

Year	Net Generating Capacity (MW)	Non-Partial Requirements Purchases (MW)	Partial Requirements Purchases (MW)	Net Firm Planned Capacity Retirements [1] (MW)	Net Firm Capacity Additions [2] (MW)	Net System Capacity (MW)	System Peak Demand [3]	Reserve Margin [4]	Excess/(Deficit) to Maintain 18% Reserve Margin
2008	1,318	337	75	(114)	296	1,912	1,545	25.0%	103
2009	1,318	337	120	(114)	296	1,957	1,593	24.7%	98
2010	1,318	237	165	(300)	296	1,717	1,483	17.7%	(3)
2011	1,318	237	45	(334)	296	1,562	1,527	2.4%	(232)
2012	1,318	237	45	(324)	296	1,571	1,560	0.7%	(261)
2013	1,318	237	0	(324)	296	1,526	1,594	-4.3%	(355)
2014	1,318	237	0	(324)	296	1,527	1,630	-6.4%	(397)
2015	1,318	237	0	(324)	296	1,527	1,668	-8.4%	(441)
2016	1,318	237	0	(324)	296	1,527	1,705	-10.5%	(486)
2017	1,318	237	0	(324)	296	1,527	1,744	-12.4%	(531)
2018	1,318	237	0	(324)	296	1,527	1,782	-14.3%	(575)
2019	1,318	237	0	(324)	296	1,527	1,820	-16.1%	(621)
2020	1,318	237	0	(324)	296	1,527	1,859	-17.9%	(666)
2021	1,318	237	0	(324)	296	1,527	1,898	-19.6%	(713)
2022	1,318	237	0	(324)	296	1,527	1,938	-21.2%	(760)
2023	1,318	237	0	(324)	296	1,527	1,978	-22.8%	(807)
2024	1,318	237	0	(324)	296	1,527	2,018	-24.3%	(854)
2025	1,318	237	0	(324)	296	1,527	2,057	-25.8%	(901)
2026	1,318	237	0	(324)	296	1,527	2,098	-27.2%	(949)
2027	1,318	237	0	(324)	296	1,527	2,139	-28.6%	(997)

[1] Includes changes to the ratings of existing nuclear generating resources and the loss of City of Vero Beach generating units associated with CROD

[2] Firm capacity additions include Treasure Coast Energy Center Unit 1 Combined Cycle (2008)

[3] City of Vero Beach's forecast capacity requirements are no longer included beginning January 1, 2010, when the CROD becomes effective, except for approximately 21 MW (summer requirement) of the City of Vero Beach's load resulting from CROD

[4] Reserve margin caluclated as (Net System Capacity - Partial Requirements Purchases) - (System Peak Demand - Partial Requirements Purchases) / (System Peak Demand - Partial Requirements Purchases).

HEARING EXHIBIT - 00000090

Table 31.C.5 - Lake Worth Unit 3 & Hansel Combined Cycle Retired
Projected Reliability Levels - Summer/Base Case - No new additions after TCEC

Year	Net Generating Capacity (MW)	Non-Partial Requirements Purchases (MW)	Partial Requirements Purchases (MW)	Net Firm Planned Capacity Retirements [1] (MW)	Net Firm Capacity Additions [2] (MW)	Net System Capacity (MW)	System Peak Demand [3]	Reserve Margin [4]	Excess/(Deficit) to Maintain 18% Reserve Margin
2008	1,318	337	75	(114)	296	1,912	1,545	25.0%	103
2009	1,318	337	120	(114)	296	1,957	1,593	24.7%	98
2010	1,318	237	165	(300)	296	1,717	1,483	17.7%	(3)
2011	1,318	237	45	(324)	296	1,572	1,527	3.0%	(222)
2012	1,318	237	45	(361)	296	1,534	1,560	-1.7%	(298)
2013	1,318	237	0	(361)	296	1,489	1,594	-6.6%	(392)
2014	1,318	237	0	(361)	296	1,490	1,630	-8.6%	(434)
2015	1,318	237	0	(361)	296	1,490	1,668	-10.7%	(478)
2016	1,318	237	0	(361)	296	1,490	1,705	-12.6%	(523)
2017	1,318	237	0	(361)	296	1,490	1,744	-14.6%	(568)
2018	1,318	237	0	(361)	296	1,490	1,782	-16.4%	(612)
2019	1,318	237	0	(361)	296	1,490	1,820	-18.1%	(658)
2020	1,318	237	0	(361)	296	1,490	1,859	-19.8%	(703)
2021	1,318	237	0	(361)	296	1,490	1,898	-21.5%	(750)
2022	1,318	237	0	(361)	296	1,490	1,938	-23.1%	(797)
2023	1,318	237	0	(361)	296	1,490	1,978	-24.7%	(844)
2024	1,318	237	0	(361)	296	1,490	2,018	-26.2%	(891)
2025	1,318	237	0	(361)	296	1,490	2,057	-27.6%	(938)
2026	1,318	237	0	(361)	296	1,490	2,098	-29.0%	(986)
2027	1,318	237	0	(361)	296	1,490	2,139	-30.3%	(1,034)

[1] Includes changes to the ratings of existing nuclear generating resources and the loss of City of Vero Beach generating units associated with CROD

[2] Firm capacity additions include Treasure Coast Energy Center Unit 1 Combined Cycle (2008)

[3] City of Vero Beach's forecast capacity requirements are no longer included beginning January 1, 2010, when the CROD becomes effective, except for approximately 21 MW (summer requirement) of the City of Vero Beach's load resulting from CROD

[4] Reserve margin cahuclated as (Net System Capacity - Partial Requirements Purchases) - (System Peak Demand - Partial Requirements Purchases) / (System Peak Demand - Partial Requirements Purchases).

HEARING EXHIBIT - 00000091

Table 31.C.6 - Lake Worth Unit 5 & Lake Worth GT1 Retired
Projected Reliability Levels - Summer/Base Case - No new additions after TCEC

Year	Net Generating Capacity (MW)	Non-Partial Requirements Purchases (MW)	Partial Requirements Purchases (MW)	Net Firm Planned Capacity Retirements [1] (MW)	Net Firm Capacity Additions [2] (MW)	Net System Capacity (MW)	System Peak Demand [3]	Reserve Margin [4]	Excess/(Deficit) to Maintain 18% Reserve Margin
2008	1,318	337	75	(114)	296	1,912	1,545	25.0%	103
2009	1,318	337	120	(114)	296	1,957	1,593	24.7%	98
2010	1,318	237	165	(300)	296	1,717	1,483	17.7%	(3)
2011	1,318	237	45	(334)	296	1,562	1,527	2.4%	(232)
2012	1,318	237	45	(324)	296	1,571	1,560	0.7%	(261)
2013	1,318	237	0	(324)	296	1,526	1,594	-4.3%	(355)
2014	1,318	237	0	(324)	296	1,527	1,630	-6.4%	(397)
2015	1,318	237	0	(324)	296	1,527	1,668	-8.4%	(441)
2016	1,318	237	0	(324)	296	1,527	1,705	-10.5%	(486)
2017	1,318	237	0	(324)	296	1,527	1,744	-12.4%	(531)
2018	1,318	237	0	(324)	296	1,527	1,782	-14.3%	(575)
2019	1,318	237	0	(324)	296	1,527	1,820	-16.1%	(621)
2020	1,318	237	0	(324)	296	1,527	1,859	-17.9%	(666)
2021	1,318	237	0	(324)	296	1,527	1,898	-19.6%	(713)
2022	1,318	237	0	(324)	296	1,527	1,938	-21.2%	(760)
2023	1,318	237	0	(324)	296	1,527	1,978	-22.8%	(807)
2024	1,318	237	0	(324)	296	1,527	2,018	-24.3%	(854)
2025	1,318	237	0	(324)	296	1,527	2,057	-25.8%	(901)
2026	1,318	237	0	(324)	296	1,527	2,098	-27.2%	(949)
2027	1,318	237	0	(324)	296	1,527	2,139	-28.6%	(997)

[1] Includes changes to the ratings of existing nuclear generating resources and the loss of City of Vero Beach generating units associated with CROD

[2] Firm capacity additions include Treasure Coast Energy Center Unit 1 Combined Cycle (2008)

[3] City of Vero Beach's forecast capacity requirements are no longer included beginning January 1, 2010, when the CROD becomes effective, except for approximately 21 MW (summer requirement) of the City of Vero Beach's load resulting from CROD

[4] Reserve margin caluclated as (Net System Capacity - Partial Requirements Purchases) - (System Peak Demand - Partial Requirements Purchases) / (System Peak Demand - Partial Requirements Purchases).

HEARING EXHIBIT - 00000092

Table 31.C.7 - Lake Worth Unit 5 & Lake Worth GT2 Retired
Projected Reliability Levels - Summer/Base Case - No new additions after TCEC

Year	Net Generating Capacity (MW)	Non-Partial Requirements Purchases (MW)	Partial Requirements Purchases (MW)	Net Firm Planned Capacity Retirements [1] (MW)	Net Firm Capacity Additions [2] (MW)	Net System Capacity (MW)	System Peak Demand [3]	Reserve Margin [4]	Excess/(Deficit) to Maintain 18% Reserve Margin
2008	1,318	337	75	(114)	296	1,912	1,545	25.0%	103
2009	1,318	337	120	(114)	296	1,957	1,593	24.7%	98
2010	1,318	237	165	(300)	296	1,717	1,483	17.7%	(3)
2011	1,318	237	45	(327)	296	1,569	1,527	2.8%	(225)
2012	1,318	237	45	(317)	296	1,578	1,560	1.2%	(254)
2013	1,318	237	0	(317)	296	1,533	1,594	-3.8%	(348)
2014	1,318	237	0	(317)	296	1,534	1,630	-5.9%	(390)
2015	1,318	237	0	(317)	296	1,534	1,668	-8.0%	(434)
2016	1,318	237	0	(317)	296	1,534	1,705	-10.1%	(479)
2017	1,318	237	0	(317)	296	1,534	1,744	-12.0%	(524)
2018	1,318	237	0	(317)	296	1,534	1,782	-13.9%	(568)
2019	1,318	237	0	(317)	296	1,534	1,820	-15.7%	(614)
2020	1,318	237	0	(317)	296	1,534	1,859	-17.5%	(659)
2021	1,318	237	0	(317)	296	1,534	1,898	-19.2%	(706)
2022	1,318	237	0	(317)	296	1,534	1,938	-20.8%	(753)
2023	1,318	237	0	(317)	296	1,534	1,978	-22.4%	(800)
2024	1,318	237	0	(317)	296	1,534	2,018	-24.0%	(847)
2025	1,318	237	0	(317)	296	1,534	2,057	-25.5%	(894)
2026	1,318	237	0	(317)	296	1,534	2,098	-26.9%	(942)
2027	1,318	237	0	(317)	296	1,534	2,139	-28.3%	(990)

[1] Includes changes to the ratings of existing nuclear generating resources and the loss of City of Vero Beach generating units associated with CROD

[2] Firm capacity additions include Treasure Coast Energy Center Unit 1 Combined Cycle (2008)

[3] City of Vero Beach's forecast capacity requirements are no longer included beginning January 1, 2010, when the CROD becomes effective, except for approximately 21 MW (summer requirement) of the City of Vero Beach's load resulting from CROD

[4] Reserve margin caluclated as (Net System Capacity - Partial Requirements Purchases) - (System Peak Demand - Partial Requirements Purchases) / (System Peak Demand - Partial Requirements Purchases).

HEARING EXHIBIT - 00000093

Table 31.C.8 - Lake Worth Unit 5 & Lake Worth D1-5 Retired
Projected Reliability Levels - Summer/Base Case - No new additions after TCEC

Year	Net Generating Capacity (MW)	Non-Partial Requirements Purchases (MW)	Partial Requirements Purchases (MW)	Net Firm Planned Capacity Retirements [1] (MW)	Net Firm Capacity Additions [2] (MW)	Net System Capacity (MW)	System Peak Demand [3]	Reserve Margin [4]	Excess/(Deficit) to Maintain 18% Reserve Margin
2008	1,318	337	75	(114)	296	1,912	1,545	25.0%	103
2009	1,318	337	120	(114)	296	1,957	1,593	24.7%	98
2010	1,318	237	165	(300)	296	1,717	1,483	17.7%	(3)
2011	1,318	237	45	(317)	296	1,579	1,527	3.5%	(215)
2012	1,318	237	45	(307)	296	1,588	1,560	1.9%	(244)
2013	1,318	237	0	(307)	296	1,543	1,594	-3.2%	(338)
2014	1,318	237	0	(307)	296	1,544	1,630	-5.3%	(380)
2015	1,318	237	0	(307)	296	1,544	1,668	-7.4%	(424)
2016	1,318	237	0	(307)	296	1,544	1,705	-9.5%	(469)
2017	1,318	237	0	(307)	296	1,544	1,744	-11.5%	(514)
2018	1,318	237	0	(307)	296	1,544	1,782	-13.3%	(558)
2019	1,318	237	0	(307)	296	1,544	1,820	-15.2%	(604)
2020	1,318	237	0	(307)	296	1,544	1,859	-16.9%	(649)
2021	1,318	237	0	(307)	296	1,544	1,898	-18.7%	(696)
2022	1,318	237	0	(307)	296	1,544	1,938	-20.3%	(743)
2023	1,318	237	0	(307)	296	1,544	1,978	-21.9%	(790)
2024	1,318	237	0	(307)	296	1,544	2,018	-23.5%	(837)
2025	1,318	237	0	(307)	296	1,544	2,057	-25.0%	(884)
2026	1,318	237	0	(307)	296	1,544	2,098	-26.4%	(932)
2027	1,318	237	0	(307)	296	1,544	2,139	-27.8%	(980)

[1] Includes changes to the ratings of existing nuclear generating resources and the loss of City of Vero Beach generating units associated with CROD

[2] Firm capacity additions include Treasure Coast Energy Center Unit 1 Combined Cycle (2008)

[3] City of Vero Beach's forecast capacity requirements are no longer included beginning January 1, 2010, when the CROD becomes effective, except for approximately 21 MW (summer requirement) of the City of Vero Beach's load resulting from CROD

[4] Reserve margin caluclated as (Net System Capacity - Partial Requirements Purchases) - (System Peak Demand - Partial Requirements Purchases) / (System Peak Demand - Partial Requirements Purchases).

HEARING EXHIBIT - 00000094

Table 31.C.9 - Lake Worth Unit 5 & Hansel Combined Cycle Retired
Projected Reliability Levels - Summer/Base Case - No new additions after TCEC

Year	Net Generating Capacity (MW)	Non-Partial Requirements Purchases (MW)	Partial Requirements Purchases (MW)	Net Firm Planned Capacity Retirements [1] (MW)	Net Firm Capacity Additions [2] (MW)	Net System Capacity (MW)	System Peak Demand [3]	Reserve Margin [4]	Excess/(Deficit) to Maintain 18% Reserve Margin
2008	1,318	337	75	(114)	296	1,912	1,545	25.0%	103
2009	1,318	337	120	(114)	296	1,957	1,593	24.7%	98
2010	1,318	237	165	(300)	296	1,717	1,483	17.7%	(3)
2011	1,318	237	45	(307)	296	1,589	1,527	4.2%	(205)
2012	1,318	237	45	(345)	296	1,551	1,560	-0.6%	(282)
2013	1,318	237	0	(345)	296	1,506	1,594	-5.5%	(375)
2014	1,318	237	0	(345)	296	1,506	1,630	-7.6%	(417)
2015	1,318	237	0	(345)	296	1,506	1,668	-9.7%	(461)
2016	1,318	237	0	(345)	296	1,506	1,705	-11.7%	(506)
2017	1,318	237	0	(345)	296	1,506	1,744	-13.6%	(551)
2018	1,318	237	0	(345)	296	1,506	1,782	-15.4%	(596)
2019	1,318	237	0	(345)	296	1,506	1,820	-17.2%	(641)
2020	1,318	237	0	(345)	296	1,506	1,859	-18.9%	(687)
2021	1,318	237	0	(345)	296	1,506	1,898	-20.6%	(733)
2022	1,318	237	0	(345)	296	1,506	1,938	-22.2%	(780)
2023	1,318	237	0	(345)	296	1,506	1,978	-23.8%	(827)
2024	1,318	237	0	(345)	296	1,506	2,018	-25.3%	(874)
2025	1,318	237	0	(345)	296	1,506	2,057	-26.8%	(921)
2026	1,318	237	0	(345)	296	1,506	2,098	-28.2%	(969)
2027	1,318	237	0	(345)	296	1,506	2,139	-29.6%	(1,017)

[1] Includes changes to the ratings of existing nuclear generating resources and the loss of City of Vero Beach generating units associated with CROD

[2] Firm capacity additions include Treasure Coast Energy Center Unit 1 Combined Cycle (2008)

[3] City of Vero Beach's forecast capacity requirements are no longer included beginning January 1, 2010, when the CROD becomes effective, except for approximately 21 MW (summer requirement) of the City of Vero Beach's load resulting from CROD

[4] Reserve margin caluclated as (Net System Capacity - Partial Requirements Purchases) - (System Peak Demand - Partial Requirements Purchases) / (System Peak Demand - Partial Requirements Purchases).

HEARING EXHIBIT - 00000095

Table 31.C.10 - Lake Worth GT1 & Lake Worth GT2 Retired
Projected Reliability Levels - Summer/Base Case - No new additions after TCEC

Year	Net Generating Capacity (MW)	Non-Partial Requirements Purchases (MW)	Partial Requirements Purchases (MW)	Net Firm Planned Capacity Retirements [1] (MW)	Net Firm Capacity Additions [2] (MW)	Net System Capacity (MW)	System Peak Demand [3]	Reserve Margin [4]	Excess/(Deficit) to Maintain 18% Reserve Margin
2008	1,318	337	75	(114)	296	1,912	1,545	25.0%	103
2009	1,318	337	120	(114)	296	1,957	1,593	24.7%	98
2010	1,318	237	165	(300)	296	1,717	1,483	17.7%	(3)
2011	1,318	237	45	(346)	296	1,550	1,527	1.6%	(244)
2012	1,318	237	45	(336)	296	1,559	1,560	0.0%	(273)
2013	1,318	237	0	(336)	296	1,514	1,594	-5.0%	(367)
2014	1,318	237	0	(336)	296	1,515	1,630	-7.1%	(409)
2015	1,318	237	0	(336)	296	1,515	1,668	-9.2%	(453)
2016	1,318	237	0	(336)	296	1,515	1,705	-11.2%	(498)
2017	1,318	237	0	(336)	296	1,515	1,744	-13.1%	(543)
2018	1,318	237	0	(336)	296	1,515	1,782	-15.0%	(587)
2019	1,318	237	0	(336)	296	1,515	1,820	-16.8%	(633)
2020	1,318	237	0	(336)	296	1,515	1,859	-18.5%	(678)
2021	1,318	237	0	(336)	296	1,515	1,898	-20.2%	(725)
2022	1,318	237	0	(336)	296	1,515	1,938	-21.8%	(772)
2023	1,318	237	0	(336)	296	1,515	1,978	-23.4%	(819)
2024	1,318	237	0	(336)	296	1,515	2,018	-24.9%	(866)
2025	1,318	237	0	(336)	296	1,515	2,057	-26.4%	(913)
2026	1,318	237	0	(336)	296	1,515	2,098	-27.8%	(961)
2027	1,318	237	0	(336)	296	1,515	2,139	-29.2%	(1,009)

[1] Includes changes to the ratings of existing nuclear generating resources and the loss of City of Vero Beach generating units associated with CROD

[2] Firm capacity additions include Treasure Coast Energy Center Unit 1 Combined Cycle (2008)

[3] City of Vero Beach's forecast capacity requirements are no longer included beginning January 1, 2010, when the CROD becomes effective, except for approximately 21 MW (summer requirement) of the City of Vero Beach's load resulting from CROD

[4] Reserve margin caluclated as (Net System Capacity - Partial Requirements Purchases) - (System Peak Demand - Partial Requirements Purchases) / (System Peak Demand - Partial Requirements Purchases).

HEARING EXHIBIT - 00000096

Table 31.C.11 - Lake Worth GT1 & Lake Worth D1-5 Retired
Projected Reliability Levels - Summer/Base Case - No new additions after TCEC

Year	Net Generating Capacity (MW)	Non-Partial Requirements Purchases (MW)	Partial Requirements Purchases (MW)	Net Firm Planned Capacity Retirements [1] (MW)	Net Firm Capacity Additions [2] (MW)	Net System Capacity (MW)	System Peak Demand [3]	Reserve Margin [4]	Excess/(Deficit) to Maintain 18% Reserve Margin
2008	1,318	337	75	(114)	296	1,912	1,545	25.0%	103
2009	1,318	337	120	(114)	296	1,957	1,593	24.7%	98
2010	1,318	237	165	(300)	296	1,717	1,483	17.7%	(3)
2011	1,318	237	45	(336)	296	1,560	1,527	2.2%	(234)
2012	1,318	237	45	(326)	296	1,569	1,560	0.6%	(263)
2013	1,318	237	0	(326)	296	1,524	1,594	-4.4%	(357)
2014	1,318	237	0	(326)	296	1,525	1,630	-6.5%	(399)
2015	1,318	237	0	(326)	296	1,525	1,668	-8.6%	(443)
2016	1,318	237	0	(326)	296	1,525	1,705	-10.6%	(488)
2017	1,318	237	0	(326)	296	1,525	1,744	-12.5%	(533)
2018	1,318	237	0	(326)	296	1,525	1,782	-14.4%	(577)
2019	1,318	237	0	(326)	296	1,525	1,820	-16.2%	(623)
2020	1,318	237	0	(326)	296	1,525	1,859	-18.0%	(668)
2021	1,318	237	0	(326)	296	1,525	1,898	-19.7%	(715)
2022	1,318	237	0	(326)	296	1,525	1,938	-21.3%	(762)
2023	1,318	237	0	(326)	296	1,525	1,978	-22.9%	(809)
2024	1,318	237	0	(326)	296	1,525	2,018	-24.4%	(856)
2025	1,318	237	0	(326)	296	1,525	2,057	-25.9%	(903)
2026	1,318	237	0	(326)	296	1,525	2,098	-27.3%	(951)
2027	1,318	237	0	(326)	296	1,525	2,139	-28.7%	(999)

[1] Includes changes to the ratings of existing nuclear generating resources and the loss of City of Vero Beach generating units associated with CROD

[2] Firm capacity additions include Treasure Coast Energy Center Unit 1 Combined Cycle (2008)

[3] City of Vero Beach's forecast capacity requirements are no longer included beginning January 1, 2010, when the CROD becomes effective, except for approximately 21 MW (summer requirement) of the City of Vero Beach's load resulting from CROD

[4] Reserve margin caluclated as (Net System Capacity - Partial Requirements Purchases) - (System Peak Demand - Partial Requirements Purchases) / (System Peak Demand - Partial Requirements Purchases).

HEARING EXHIBIT - 00000097

Table 31.C.12 - Lake Worth GT1 & Hansel Combined Cycle Retired
Projected Reliability Levels - Summer/Base Case - No new additions after TCEC

Year	Net Generating Capacity (MW)	Non-Partial Requirements Purchases (MW)	Partial Requirements Purchases (MW)	Net Firm Planned Capacity Retirements [1] (MW)	Net Firm Capacity Additions [2] (MW)	Net System Capacity (MW)	System Peak Demand [3]	Reserve Margin [4]	Excess/(Deficit) to Maintain 18% Reserve Margin
2008	1,318	337	75	(114)	296	1,912	1,545	25.0%	103
2009	1,318	337	120	(114)	296	1,957	1,593	24.7%	98
2010	1,318	237	165	(300)	296	1,717	1,483	17.7%	(3)
2011	1,318	237	45	(326)	296	1,570	1,527	2.9%	(224)
2012	1,318	237	45	(364)	296	1,532	1,560	-1.8%	(301)
2013	1,318	237	0	(364)	296	1,487	1,594	-6.7%	(394)
2014	1,318	237	0	(364)	296	1,487	1,630	-8.8%	(436)
2015	1,318	237	0	(364)	296	1,487	1,668	-10.8%	(480)
2016	1,318	237	0	(364)	296	1,487	1,705	-12.8%	(525)
2017	1,318	237	0	(364)	296	1,487	1,744	-14.7%	(570)
2018	1,318	237	0	(364)	296	1,487	1,782	-16.5%	(615)
2019	1,318	237	0	(364)	296	1,487	1,820	-18.3%	(660)
2020	1,318	237	0	(364)	296	1,487	1,859	-20.0%	(706)
2021	1,318	237	0	(364)	296	1,487	1,898	-21.6%	(752)
2022	1,318	237	0	(364)	296	1,487	1,938	-23.2%	(799)
2023	1,318	237	0	(364)	296	1,487	1,978	-24.8%	(846)
2024	1,318	237	0	(364)	296	1,487	2,018	-26.3%	(893)
2025	1,318	237	0	(364)	296	1,487	2,057	-27.7%	(940)
2026	1,318	237	0	(364)	296	1,487	2,098	-29.1%	(988)
2027	1,318	237	0	(364)	296	1,487	2,139	-30.5%	(1,036)

[1] Includes changes to the ratings of existing nuclear generating resources and the loss of City of Vero Beach generating units associated with CROD

[2] Firm capacity additions include Treasure Coast Energy Center Unit 1 Combined Cycle (2008)

[3] City of Vero Beach's forecast capacity requirements are no longer included beginning January 1, 2010, when the CROD becomes effective, except for approximately 21 MW (summer requirement) of the City of Vero Beach's load resulting from CROD

[4] Reserve margin caluclated as (Net System Capacity - Partial Requirements Purchases) - (System Peak Demand - Partial Requirements Purchases) / (System Peak Demand - Partial Requirements Purchases).

HEARING EXHIBIT - 00000098

Table 31.C.13 - Lake Worth GT2 & Lake Worth D1-5 Retired
Projected Reliability Levels - Summer/Base Case - No new additions after TCEC

Year	Net Generating Capacity (MW)	Non-Partial Requirements Purchases (MW)	Partial Requirements Purchases (MW)	Net Firm Planned Capacity Retirements [1] (MW)	Net Firm Capacity Additions [2] (MW)	Net System Capacity (MW)	System Peak Demand [3]	Reserve Margin [4]	Excess/(Deficit) to Maintain 18% Reserve Margin
2008	1,318	337	75	(114)	296	1,912	1,545	25.0%	103
2009	1,318	337	120	(114)	296	1,957	1,593	24.7%	98
2010	1,318	237	165	(300)	296	1,717	1,483	17.7%	(3)
2011	1,318	237	45	(329)	296	1,567	1,527	2.7%	(227)
2012	1,318	237	45	(319)	296	1,576	1,560	1.1%	(256)
2013	1,318	237	0	(319)	296	1,531	1,594	-4.0%	(350)
2014	1,318	237	0	(319)	296	1,532	1,630	-6.1%	(392)
2015	1,318	237	0	(319)	296	1,532	1,668	-8.1%	(436)
2016	1,318	237	0	(319)	296	1,532	1,705	-10.2%	(481)
2017	1,318	237	0	(319)	296	1,532	1,744	-12.1%	(526)
2018	1,318	237	0	(319)	296	1,532	1,782	-14.0%	(570)
2019	1,318	237	0	(319)	296	1,532	1,820	-15.8%	(616)
2020	1,318	237	0	(319)	296	1,532	1,859	-17.6%	(661)
2021	1,318	237	0	(319)	296	1,532	1,898	-19.3%	(708)
2022	1,318	237	0	(319)	296	1,532	1,938	-20.9%	(755)
2023	1,318	237	0	(319)	296	1,532	1,978	-22.5%	(802)
2024	1,318	237	0	(319)	296	1,532	2,018	-24.1%	(849)
2025	1,318	237	0	(319)	296	1,532	2,057	-25.6%	(896)
2026	1,318	237	0	(319)	296	1,532	2,098	-27.0%	(944)
2027	1,318	237	0	(319)	296	1,532	2,139	-28.4%	(992)

[1] Includes changes to the ratings of existing nuclear generating resources and the loss of City of Vero Beach generating units associated with CROD

[2] Firm capacity additions include Treasure Coast Energy Center Unit 1 Combined Cycle (2008)

[3] City of Vero Beach's forecast capacity requirements are no longer included beginning January 1, 2010, when the CROD becomes effective, except for approximately 21 MW (summer requirement) of the City of Vero Beach's load resulting from CROD

[4] Reserve margin caluclated as (Net System Capacity - Partial Requirements Purchases) - (System Peak Demand - Partial Requirements Purchases) / (System Peak Demand - Partial Requirements Purchases).

HEARING EXHIBIT - 00000099

Table 31.C.14 - Lake Worth GT2 & Hansel Combined Cycle Retired
Projected Reliability Levels - Summer/Base Case - No new additions after TCEC

Year	Net Generating Capacity (MW)	Non-Partial Requirements Purchases (MW)	Partial Requirements Purchases (MW)	Net Firm Planned Capacity Retirements [1] (MW)	Net Firm Capacity Additions [2] (MW)	Net System Capacity (MW)	System Peak Demand [3]	Reserve Margin [4]	Excess/(Deficit) to Maintain 18% Reserve Margin
2008	1,318	337	75	(114)	296	1,912	1,545	25.0%	103
2009	1,318	337	120	(114)	296	1,957	1,593	24.7%	98
2010	1,318	237	165	(300)	296	1,717	1,483	17.7%	(3)
2011	1,318	237	45	(319)	296	1,577	1,527	3.4%	(217)
2012	1,318	237	45	(356)	296	1,539	1,560	-1.4%	(293)
2013	1,318	237	0	(356)	296	1,494	1,594	-6.3%	(387)
2014	1,318	237	0	(356)	296	1,495	1,630	-8.3%	(429)
2015	1,318	237	0	(356)	296	1,495	1,668	-10.4%	(473)
2016	1,318	237	0	(356)	296	1,495	1,705	-12.4%	(518)
2017	1,318	237	0	(356)	296	1,495	1,744	-14.3%	(563)
2018	1,318	237	0	(356)	296	1,495	1,782	-16.1%	(607)
2019	1,318	237	0	(356)	296	1,495	1,820	-17.9%	(653)
2020	1,318	237	0	(356)	296	1,495	1,859	-19.6%	(698)
2021	1,318	237	0	(356)	296	1,495	1,898	-21.2%	(745)
2022	1,318	237	0	(356)	296	1,495	1,938	-22.9%	(792)
2023	1,318	237	0	(356)	296	1,495	1,978	-24.4%	(839)
2024	1,318	237	0	(356)	296	1,495	2,018	-25.9%	(886)
2025	1,318	237	0	(356)	296	1,495	2,057	-27.3%	(933)
2026	1,318	237	0	(356)	296	1,495	2,098	-28.7%	(981)
2027	1,318	237	0	(356)	296	1,495	2,139	-30.1%	(1,029)

[1] Includes changes to the ratings of existing nuclear generating resources and the loss of City of Vero Beach generating units associated with CROD

[2] Firm capacity additions include Treasure Coast Energy Center Unit 1 Combined Cycle (2008)

[3] City of Vero Beach's forecast capacity requirements are no longer included beginning January 1, 2010, when the CROD becomes effective, except for approximately 21 MW (summer requirement) of the City of Vero Beach's load resulting from CROD

[4] Reserve margin caluclated as (Net System Capacity - Partial Requirements Purchases) - (System Peak Demand - Partial Requirements Purchases) / (System Peak Demand - Partial Requirements Purchases).

HEARING EXHIBIT - 00000100

Table 31.C.15 - Lake Worth D1-5 & Hansel Combined Cycle Retired
Projected Reliability Levels - Summer/Base Case - No new additions after TCEC

Year	Net Generating Capacity (MW)	Non-Partial Requirements Purchases (MW)	Partial Requirements Purchases (MW)	Net Firm Planned Capacity Retirements [1] (MW)	Net Firm Capacity Additions [2] (MW)	Net System Capacity (MW)	System Peak Demand [3]	Reserve Margin [4]	Excess/(Deficit) to Maintain 18% Reserve Margin
2008	1,318	337	75	(114)	296	1,912	1,545	25.0%	103
2009	1,318	337	120	(114)	296	1,957	1,593	24.7%	98
2010	1,318	237	165	(300)	296	1,717	1,483	17.7%	(3)
2011	1,318	237	45	(309)	296	1,587	1,527	4.1%	(207)
2012	1,318	237	45	(346)	296	1,549	1,560	-0.7%	(283)
2013	1,318	237	0	(346)	296	1,504	1,594	-5.7%	(377)
2014	1,318	237	0	(346)	296	1,505	1,630	-7.7%	(419)
2015	1,318	237	0	(346)	296	1,505	1,668	-9.8%	(463)
2016	1,318	237	0	(346)	296	1,505	1,705	-11.8%	(508)
2017	1,318	237	0	(346)	296	1,505	1,744	-13.7%	(553)
2018	1,318	237	0	(346)	296	1,505	1,782	-15.5%	(597)
2019	1,318	237	0	(346)	296	1,505	1,820	-17.3%	(643)
2020	1,318	237	0	(346)	296	1,505	1,859	-19.0%	(688)
2021	1,318	237	0	(346)	296	1,505	1,898	-20.7%	(735)
2022	1,318	237	0	(346)	296	1,505	1,938	-22.3%	(782)
2023	1,318	237	0	(346)	296	1,505	1,978	-23.9%	(829)
2024	1,318	237	0	(346)	296	1,505	2,018	-25.4%	(876)
2025	1,318	237	0	(346)	296	1,505	2,057	-26.9%	(923)
2026	1,318	237	0	(346)	296	1,505	2,098	-28.3%	(971)
2027	1,318	237	0	(346)	296	1,505	2,139	-29.6%	(1,019)

[1] Includes changes to the ratings of existing nuclear generating resources and the loss of City of Vero Beach generating units associated with CROD

[2] Firm capacity additions include Treasure Coast Energy Center Unit 1 Combined Cycle (2008)

[3] City of Vero Beach's forecast capacity requirements are no longer included beginning January 1, 2010, when the CROD becomes effective, except for approximately 21 MW (summer requirement) of the City of Vero Beach's load resulting from CROD

[4] Reserve margin calculated as (Net System Capacity - Partial Requirements Purchases) - (System Peak Demand - Partial Requirements Purchases) / (System Peak Demand - Partial Requirements Purchases).

HEARING EXHIBIT - 00000101

Attachment 49

FMPA's Response to the Staff's 4th Set of Interrogatories

	Scenario 1.1A - Conventional Expansion Scenario With Cane Island 4					
	Reference Case					
	($000, 2008$)					
	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2008	-	-	333,551	71,966	405,517	405,517
2009	-	7,359	301,976	75,271	384,607	790,124
2010	-	2,958	260,060	73,454	336,472	1,126,595
2011	17,586	2,876	265,024	52,957	338,442	1,465,038
2012	32,429	2,830	258,933	55,386	349,579	1,814,616
2013	38,169	2,861	260,612	49,759	351,401	2,166,018
2014	36,352	2,899	265,430	44,111	348,791	2,514,809
2015	34,621	2,875	266,562	43,364	347,421	2,862,230
2016	32,972	3,017	268,403	43,477	347,870	3,210,100
2017	31,402	2,794	262,060	44,861	341,117	3,551,217
2018	29,907	2,880	255,139	45,552	333,478	3,884,694
2019	33,680	2,777	250,729	46,559	333,745	4,218,440
2020	32,077	2,706	241,361	47,095	323,238	4,541,678
2021	30,549	2,685	240,207	47,298	320,740	4,862,418
2022	33,901	2,785	244,213	47,123	328,023	5,190,441
2023	32,287	2,791	245,802	46,222	327,103	5,517,543
2024	35,312	2,805	254,744	46,076	338,937	5,856,480
2025	33,630	2,784	254,893	45,200	336,507	6,192,987
2026	35,618	2,734	253,621	44,236	336,209	6,529,196
2027	35,818	2,656	260,863	44,970	344,307	6,873,503

HEARING EXHIBIT - 00000103

	Scenario 1.1C - Conventional Expansion Scenario Without Cane Island 4					
	Reference Case					
	($000, 2008$)					
	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2008	-	-	333,551	71,966	405,517	405,517
2009	-	7,359	301,976	75,271	384,607	790,124
2010	-	2,958	260,060	73,454	336,472	1,126,595
2011	15,349	3,324	273,832	59,830	352,335	1,478,930
2012	20,855	3,074	266,350	59,903	350,182	1,829,112
2013	36,555	2,878	259,753	49,060	348,246	2,177,359
2014	42,601	2,869	264,430	45,032	354,932	2,532,291
2015	40,573	2,841	265,381	44,204	352,999	2,885,290
2016	38,641	2,981	267,170	44,283	353,075	3,238,365
2017	36,801	2,765	260,894	45,639	346,099	3,584,464
2018	35,048	2,848	254,006	46,317	338,220	3,922,683
2019	33,379	2,777	250,729	46,559	333,445	4,256,128
2020	31,790	2,706	241,361	47,095	322,952	4,579,080
2021	30,276	2,685	240,207	47,298	320,467	4,899,547
2022	33,841	2,785	244,213	47,123	327,763	5,227,310
2023	32,039	2,791	245,802	46,223	326,855	5,554,165
2024	35,076	2,805	254,744	46,076	338,701	5,892,866
2025	33,406	2,784	254,893	45,199	336,282	6,229,149
2026	34,573	2,734	253,621	45,067	335,995	6,565,144
2027	35,614	2,656	260,863	44,970	344,103	6,909,247

HEARING EXHIBIT - 00000104

	Scenario 1.2A - Conventional Expansion Scenario With Cane Island 4 High Fuel Price Case ($000, 2008$)					
	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2008	-	-	346,909	71,978	418,887	418,887
2009	-	7,734	318,486	79,758	405,978	824,865
2010	-	3,115	276,602	78,195	357,912	1,182,777
2011	17,586	2,861	292,889	59,265	372,582	1,555,359
2012	32,429	2,711	281,803	58,331	375,274	1,930,633
2013	38,169	2,865	287,672	53,263	381,970	2,312,603
2014	36,352	2,969	297,182	44,121	380,624	2,693,227
2015	34,621	2,961	303,489	43,381	384,452	3,077,679
2016	32,972	2,917	306,788	43,496	386,173	3,463,852
2017	31,402	2,805	297,490	44,912	376,609	3,840,462
2018	29,907	2,766	285,400	45,570	363,643	4,204,104
2019	33,680	2,784	272,141	46,566	355,171	4,559,275
2020	32,077	2,785	266,981	47,100	348,942	4,908,218
2021	30,549	2,691	274,832	47,330	355,402	5,263,620
2022	33,901	2,677	278,308	47,155	362,041	5,625,661
2023	32,287	2,543	284,088	46,286	365,205	5,990,866
2024	35,312	2,448	290,541	46,120	374,420	6,365,286
2025	33,630	2,308	296,031	45,252	377,221	6,742,507
2026	35,618	2,121	301,517	44,285	383,541	7,126,048
2027	35,818	2,012	312,128	45,017	394,975	7,521,023

HEARING EXHIBIT - 00000105

	Scenario 1.2C - Conventional Expansion Scenario Without Cane Island 4 High Fuel Price Case ($000, 2008$)					
	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2008	-	-	346,909	71,978	418,887	418,887
2009	-	7,734	318,466	79,758	405,978	824,865
2010	-	3,115	276,602	78,195	357,912	1,182,777
2011	15,349	3,307	305,117	64,100	387,873	1,570,650
2012	20,855	2,954	293,191	59,939	376,939	1,947,589
2013	36,555	2,884	287,915	51,493	378,846	2,326,435
2014	42,601	2,938	296,043	45,036	386,618	2,713,053
2015	40,573	2,925	302,115	44,209	389,822	3,102,875
2016	38,641	2,883	305,346	44,287	391,157	3,494,032
2017	36,801	2,776	296,140	45,663	381,380	3,875,412
2018	35,048	2,735	284,091	46,338	368,213	4,243,625
2019	33,379	2,784	272,141	46,566	354,870	4,598,495
2020	31,790	2,785	266,981	47,100	348,655	4,947,150
2021	30,276	2,691	274,832	47,330	355,129	5,302,279
2022	33,641	2,677	278,308	47,155	361,781	5,664,060
2023	32,039	2,543	284,088	46,288	364,957	6,029,018
2024	35,076	2,448	290,541	46,119	374,184	6,403,202
2025	33,406	2,308	296,031	45,252	376,996	6,780,198
2026	34,573	2,121	301,517	45,116	383,327	7,163,525
2027	35,614	2,012	312,128	45,017	394,771	7,558,296

HEARING EXHIBIT - 00000106

	Scenario 1.3A - Conventional Expansion Scenario With Cane Island 4 Low Fuel Price Case ($000, 2008$)					
	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2008	-	-	325,104	68,570	393,674	393,674
2009	-	7,576	292,793	66,110	366,479	760,153
2010	-	3,261	244,707	65,641	313,608	1,073,761
2011	17,586	3,027	244,051	51,702	316,366	1,390,127
2012	32,429	2,805	230,214	54,372	319,819	1,709,946
2013	38,169	2,785	226,000	49,276	316,230	2,026,177
2014	36,352	2,818	225,677	44,016	308,863	2,335,040
2015	34,621	2,932	223,781	43,237	304,571	2,639,611
2016	32,972	2,868	227,152	43,377	306,369	2,945,980
2017	31,402	2,669	217,837	44,767	296,674	3,242,654
2018	29,907	2,637	215,582	45,462	293,587	3,536,241
2019	33,680	2,620	215,819	46,516	298,635	3,834,877
2020	32,077	2,607	205,389	47,058	287,130	4,122,007
2021	30,549	2,728	208,134	47,244	288,655	4,410,663
2022	34,856	2,605	212,890	47,273	297,624	4,708,287
2023	33,196	2,622	212,314	46,382	294,513	5,002,800
2024	31,616	2,659	220,219	45,569	300,063	5,302,863
2025	34,556	2,603	222,277	45,333	304,768	5,607,631
2026	32,910	2,640	220,865	44,506	300,921	5,908,552
2027	34,030	2,609	225,526	44,424	306,589	6,215,141

HEARING EXHIBIT - 00000107

	Scenario 1.3C - Conventional Expansion Scenario Without Cane Island 4					
	Low Fuel Price Case					
	($000, 2008$)					
	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2008	-	-	325,104	68,570	393,674	393,674
2009	-	7,576	292,793	66,110	366,479	760,153
2010	-	3,261	244,707	65,841	313,808	1,073,761
2011	15,349	3,460	252,328	58,319	329,456	1,403,217
2012	20,855	3,032	237,099	58,352	319,338	1,722,555
2013	36,555	2,803	218,049	57,488	314,896	2,037,450
2014	42,601	2,789	224,150	44,984	314,525	2,351,975
2015	40,573	2,897	222,126	44,135	309,731	2,661,706
2016	38,641	2,839	225,507	44,232	311,220	2,972,926
2017	38,801	2,643	216,353	45,593	301,390	3,274,316
2018	35,048	2,610	214,123	46,277	298,059	3,572,374
2019	33,379	2,619	215,174	46,512	297,685	3,870,059
2020	31,790	2,606	204,781	47,053	286,231	4,156,290
2021	30,276	2,727	207,505	47,240	287,749	4,444,038
2022	34,597	2,604	212,265	47,269	296,735	4,740,773
2023	32,949	2,621	211,695	46,377	293,642	5,034,415
2024	31,380	2,658	219,552	45,565	299,156	5,333,571
2025	34,331	2,602	221,613	45,333	303,879	5,637,450
2026	32,696	2,639	220,202	44,503	300,040	5,937,491
2027	33,827	2,607	224,826	44,421	305,681	6,243,171

HEARING EXHIBIT - 00000108

	Scenario 1.4A - Conventional Expansion Scenario With Cane Island 4 High Load Case ($000, 2008$)					
	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2008	-	-	346,463	73,113	419,576	419,576
2009	-	7,467	315,394	77,928	400,789	820,365
2010	-	3,104	274,331	78,195	355,630	1,175,995
2011	23,988	2,895	281,392	55,613	363,888	1,539,882
2012	38,526	2,875	277,045	58,085	376,531	1,916,413
2013	43,976	2,921	281,157	52,311	380,364	2,296,778
2014	41,882	2,972	288,797	46,520	380,171	2,676,949
2015	45,656	2,920	290,990	46,740	386,306	3,063,255
2016	43,482	3,074	295,721	46,937	389,214	3,452,470
2017	41,412	2,858	292,589	48,395	385,253	3,837,723
2018	39,440	2,960	288,005	49,185	379,590	4,217,313
2019	42,759	2,868	286,405	50,317	382,349	4,599,661
2020	40,723	2,803	279,339	50,919	373,784	4,973,445
2021	44,698	2,802	280,841	52,171	380,511	5,353,956
2022	42,569	2,944	288,885	51,386	385,784	5,739,740
2023	45,225	2,931	292,805	51,280	392,241	6,131,981
2024	47,634	2,958	305,865	51,218	407,676	6,539,657
2025	45,366	2,953	308,620	50,452	407,391	6,947,048
2026	48,398	2,926	310,409	50,579	412,312	7,359,360
2027	46,093	2,871	321,831	49,995	420,789	7,780,149

HEARING EXHIBIT - 00000109

	Scenario 1.4C - Conventional Expansion Scenario Without Cane Island 4					
	High Load Case					
	($000, 2008$)					
	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2008	-	-	346,463	73,113	419,576	419,576
2009	-	7,467	315,394	77,928	400,789	820,365
2010	-	3,104	274,331	78,195	355,630	1,175,995
2011	21,750	3,311	290,745	62,376	378,182	1,554,177
2012	26,952	3,114	285,722	62,650	378,438	1,932,615
2013	42,362	2,944	280,775	51,697	377,778	2,310,393
2014	48,132	2,939	287,828	47,432	386,331	2,696,724
2015	45,840	2,920	290,990	46,740	386,490	3,083,214
2016	43,657	3,074	295,721	46,937	389,389	3,472,603
2017	41,578	2,858	292,589	48,396	385,420	3,858,023
2018	39,598	2,960	288,005	49,186	379,749	4,237,772
2019	42,910	2,868	286,405	50,317	382,500	4,620,271
2020	40,866	2,803	279,339	50,919	373,928	4,994,199
2021	44,834	2,802	280,788	52,225	380,649	5,374,848
2022	42,699	2,944	288,685	51,386	385,914	5,760,762
2023	45,349	2,931	292,805	51,280	392,365	6,153,127
2024	47,753	2,958	305,865	51,219	407,795	6,560,922
2025	45,479	2,953	308,620	50,452	407,504	6,968,426
2026	48,505	2,926	310,409	50,579	412,419	7,380,845
2027	46,195	2,871	321,831	49,995	420,892	7,801,736

HEARING EXHIBIT - 00000110

	Scenario 1.5A - Conventional Expansion Scenario With Cane Island 4					
	Low Load Case					
	($000, 2008$)					
	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2008	-	-	320,775	70,834	391,609	391,609
2009	-	7,262	288,779	72,567	368,608	760,217
2010	-	2,825	246,483	68,851	318,160	1,078,376
2011	17,586	2,771	248,160	51,278	319,796	1,398,172
2012	24,952	2,759	240,474	52,703	320,888	1,719,060
2013	31,049	2,778	239,605	47,118	320,550	2,039,610
2014	29,570	2,799	241,531	41,564	315,464	2,355,074
2015	28,162	2,764	240,358	40,658	311,942	2,667,016
2016	26,821	2,890	239,273	40,655	309,639	2,976,655
2017	25,544	2,674	229,960	41,955	300,132	3,276,788
2018	24,327	2,741	221,099	42,560	290,727	3,567,515
2019	23,169	2,659	215,238	42,721	283,787	3,851,302
2020	22,066	2,585	203,659	43,213	271,523	4,122,826
2021	21,015	2,543	200,347	43,310	267,215	4,390,041
2022	20,014	2,651	201,833	42,306	266,804	4,656,845
2023	22,591	2,647	200,386	42,181	267,805	4,924,650
2024	21,515	2,664	206,133	41,227	271,540	5,196,190
2025	20,491	2,630	203,818	40,261	267,200	5,463,390
2026	22,273	2,568	199,921	40,050	264,812	5,728,202
2027	21,212	2,491	203,706	39,142	266,552	5,994,754

HEARING EXHIBIT - 00000111

	Scenario 1.5C - Conventional Expansion Scenario Without Cane Island 4 Low Load Case ($000, 2008$)					
	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2008	-	-	320,775	70,834	391,609	391,609
2009	-	7,262	288,779	72,567	368,608	760,217
2010	-	2,825	246,483	68,851	318,160	1,078,376
2011	14,076	3,010	252,603	57,689	327,379	1,405,755
2012	19,643	2,901	243,923	57,703	324,169	1,729,925
2013	24,784	2,894	244,622	50,537	322,838	2,052,762
2014	23,604	2,927	248,415	43,630	318,577	2,371,339
2015	22,480	2,889	247,773	42,681	315,823	2,687,162
2016	21,410	3,017	246,529	42,625	313,580	3,000,743
2017	20,390	2,778	236,486	43,876	303,530	3,304,273
2018	19,419	2,850	227,266	44,423	293,959	3,598,232
2019	18,495	2,763	221,382	44,542	287,182	3,885,413
2020	17,614	2,678	208,894	44,981	274,167	4,159,581
2021	21,709	2,620	205,266	45,828	275,423	4,435,003
2022	20,675	2,732	206,946	44,749	275,101	4,710,105
2023	19,690	2,723	205,493	43,702	271,608	4,981,713
2024	18,753	2,745	211,774	42,699	275,971	5,257,684
2025	21,210	2,712	209,540	42,511	275,974	5,533,657
2026	20,200	2,663	205,767	41,508	270,138	5,803,795
2027	19,238	2,588	210,062	40,553	272,441	6,076,237

HEARING EXHIBIT - 00000112

	Scenario 1.6A - Conventional Expansion Scenario With Cane Island 4					
	High Capital Case					
	($000, 2008$)					
	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2008	-	-	333,551	71,966	405,517	405,517
2009	-	7,359	301,976	75,271	384,607	790,124
2010	-	2,958	260,060	73,454	336,472	1,126,595
2011	21,104	2,876	265,024	52,957	341,960	1,468,555
2012	38,915	2,830	258,933	55,386	356,065	1,824,620
2013	45,803	2,861	260,612	49,759	359,035	2,183,655
2014	43,622	2,899	265,430	44,111	356,062	2,539,717
2015	41,545	2,875	266,562	43,364	354,346	2,894,062
2016	39,567	3,017	268,403	43,477	354,464	3,248,526
2017	37,682	2,794	262,060	44,861	347,397	3,596,923
2018	35,888	2,880	255,139	45,552	339,459	3,936,382
2019	40,416	2,777	250,729	46,559	340,481	4,276,864
2020	38,492	2,706	241,361	47,095	329,653	4,606,517
2021	36,659	2,685	240,207	47,298	326,850	4,932,367
2022	40,681	2,785	244,213	47,123	334,803	5,267,170
2023	38,744	2,791	245,802	46,223	333,560	5,600,730
2024	42,374	2,805	254,744	46,076	345,999	5,946,729
2025	40,357	2,784	254,893	45,199	343,233	6,289,962
2026	41,744	2,734	253,621	45,067	343,166	6,633,129
2027	42,981	2,656	260,863	44,970	351,470	6,984,599

HEARING EXHIBIT - 00000113

	Scenario 1.6C - Conventional Expansion Scenario Without Cane Island 4 High Capital Case ($000, 2008$)					
	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2008	-	-	333,551	71,966	405,517	405,517
2009	-	7,359	301,976	75,271	384,607	790,124
2010	-	2,958	260,060	73,454	336,472	1,126,595
2011	18,418	3,324	273,832	59,830	355,404	1,482,000
2012	25,026	3,074	266,350	59,903	354,353	1,836,352
2013	43,866	2,878	259,753	49,060	355,557	2,191,910
2014	51,122	2,869	264,430	45,032	363,452	2,555,362
2015	48,687	2,841	265,381	44,204	361,114	2,916,476
2016	46,369	2,981	267,170	44,283	360,803	3,277,279
2017	44,161	2,765	260,894	45,639	353,459	3,630,738
2018	42,058	2,848	254,006	46,317	345,229	3,975,968
2019	40,055	2,777	250,729	46,559	340,121	4,316,088
2020	38,148	2,706	241,361	47,095	329,310	4,645,398
2021	36,331	2,685	240,207	47,298	326,522	4,971,920
2022	40,369	2,785	244,213	47,123	334,491	5,306,412
2023	38,447	2,791	245,802	46,223	333,263	5,639,675
2024	42,091	2,805	254,744	46,076	345,716	5,985,391
2025	40,087	2,784	254,893	45,200	342,964	6,328,354
2026	41,488	2,734	253,621	45,067	342,910	6,671,265
2027	42,737	2,656	260,863	44,970	351,226	7,022,490

HEARING EXHIBIT - 00000114

	Scenario 1.7A - Conventional Expansion Scenario With Cane Island 4					
	Regulated CO_2 Case					
	($000, 2008$)					
	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2008	-	-	333,551	71,961	405,512	405,512
2009	-	7,359	301,976	75,268	384,603	790,115
2010	-	2,958	260,060	73,430	336,448	1,126,563
2011	17,586	2,878	265,024	52,933	338,419	1,464,982
2012	32,429	44,637	256,200	58,305	391,571	1,856,553
2013	38,169	47,423	254,970	51,222	391,784	2,248,337
2014	36,352	49,574	259,310	44,107	389,342	2,637,679
2015	34,621	50,960	259,043	43,169	387,792	3,025,472
2016	32,972	53,845	259,526	43,316	389,659	3,415,131
2017	31,402	56,076	250,418	44,885	382,781	3,797,912
2018	29,907	58,866	243,039	45,646	377,458	4,175,370
2019	33,680	62,075	239,830	46,615	382,200	4,557,570
2020	32,077	62,342	228,954	46,939	370,312	4,927,883
2021	30,549	66,825	228,804	47,178	373,357	5,301,240
2022	33,901	70,749	233,545	46,970	385,166	5,686,406
2023	32,287	75,343	232,816	46,095	386,541	6,072,947
2024	35,312	80,832	237,160	45,834	399,137	6,472,084
2025	33,630	86,312	240,283	44,978	405,204	6,877,288
2026	34,787	90,867	239,760	44,845	410,259	7,287,547
2027	35,818	99,106	241,378	44,792	421,093	7,708,640

HEARING EXHIBIT - 00000115

	Scenario 1.7C - Conventional Expansion Scenario Without Cane Island 4 Regulated CO_2 Case ($000, 2008$)					
	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2008	-	-	333,551	71,961	405,512	405,512
2009	-	7,359	301,976	75,268	384,603	790,115
2010	-	2,958	260,060	73,430	336,448	1,126,563
2011	15,349	3,324	273,832	59,813	352,318	1,478,881
2012	20,855	46,168	266,438	59,889	393,350	1,872,231
2013	36,555	47,475	255,172	49,459	388,660	2,260,890
2014	42,601	49,393	258,331	45,030	395,355	2,656,246
2015	40,573	50,738	257,903	44,014	393,228	3,049,474
2016	38,641	53,606	258,350	44,112	394,709	3,444,183
2017	36,801	55,846	249,309	45,654	387,610	3,831,792
2018	35,048	58,627	241,979	46,369	382,023	4,213,816
2019	33,379	62,075	239,830	46,616	381,900	4,595,716
2020	31,790	62,342	228,954	46,940	370,026	4,965,742
2021	30,276	66,825	228,804	47,179	373,085	5,338,827
2022	33,641	70,749	233,545	46,971	384,906	5,723,733
2023	32,039	75,343	232,816	46,095	386,293	6,110,026
2024	35,076	80,832	237,160	45,833	398,901	6,508,927
2025	33,406	86,312	240,283	44,978	404,979	6,913,907
2026	34,573	90,867	239,760	44,845	410,045	7,323,951
2027	35,614	99,106	241,378	44,792	420,890	7,744,841

HEARING EXHIBIT - 00000116

	Scenario 1.8A - Conventional Expansion Scenario With Cane Island 4					
	High Fuel with Regulated CO_2 Case					
	($000, 2008$)					
	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2008	-	-	346,909	71,978	418,887	418,887
2009	-	7,734	318,486	79,758	405,978	824,865
2010	-	3,115	276,602	78,195	357,912	1,182,777
2011	17,586	2,861	292,869	59,265	372,582	1,555,359
2012	32,429	44,141	278,041	62,291	416,902	1,972,261
2013	38,169	47,203	287,647	53,341	426,360	2,398,622
2014	36,352	49,846	297,041	44,205	427,244	2,825,866
2015	34,621	51,976	303,274	43,489	433,359	3,259,225
2016	32,972	54,743	306,486	43,602	437,803	3,697,028
2017	31,402	56,109	297,360	44,983	429,854	4,126,882
2018	29,907	58,809	285,263	45,672	419,651	4,546,533
2019	33,680	62,082	272,083	46,625	414,470	4,961,003
2020	32,077	63,912	266,915	47,155	410,058	5,371,062
2021	30,549	68,265	274,835	47,381	421,029	5,792,091
2022	33,901	57,758	278,278	62,323	432,260	6,224,351
2023	32,287	77,428	284,047	46,287	440,049	6,664,400
2024	35,312	83,817	290,486	46,119	455,734	7,120,134
2025	33,630	89,682	295,886	45,252	464,450	7,584,584
2026	34,787	95,126	301,382	45,115	476,409	8,060,993
2027	35,818	103,113	311,976	45,017	495,924	8,556,917

HEARING EXHIBIT - 00000117

	Scenario 1.8C - Conventional Expansion Scenario Without Cane Island 4					
	High Fuel with Regulated CO_2 Case					
	($000, 2008$)					
	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2008	-	-	346,909	71,978	418,887	418,887
2009	-	7,734	318,486	79,758	405,978	824,865
2010	-	3,116	276,602	78,194	357,912	1,182,777
2011	15,349	3,307	305,117	64,100	387,873	1,570,650
2012	20,855	45,653	289,361	64,049	419,917	1,990,567
2013	36,555	47,258	287,902	51,544	423,260	2,413,827
2014	42,601	49,467	295,177	45,824	433,070	2,846,896
2015	40,573	51,758	301,927	44,265	438,523	3,285,420
2016	38,641	54,510	305,070	44,344	442,566	3,727,985
2017	36,801	55,882	296,028	45,701	434,412	4,162,397
2018	35,048	58,570	283,987	46,377	423,983	4,586,381
2019	33,379	62,082	272,083	46,625	414,169	5,000,550
2020	31,790	63,912	266,915	47,155	409,772	5,410,322
2021	30,276	68,265	274,835	47,381	420,756	5,831,079
2022	33,641	72,910	278,278	47,171	432,000	6,263,078
2023	32,039	77,428	284,047	46,287	439,801	6,702,879
2024	35,076	83,817	290,486	46,119	455,498	7,158,378
2025	33,406	89,682	295,886	45,252	464,226	7,622,604
2026	34,573	95,126	301,382	45,116	476,196	8,098,800
2027	35,614	103,113	311,976	45,017	495,720	8,594,520

HEARING EXHIBIT - 00000118

	Scenario 1.9A - Conventional Expansion Scenario With Cane Island 4					
	High Regulated CO_2 Case					
	($000, 2008$)					
	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2008	-	-	333,551	71,966	405,517	405,517
2009	-	7,359	301,976	75,271	384,607	790,124
2010	-	2,958	260,060	73,454	336,472	1,126,595
2011	17,586	2,876	265,024	52,957	338,442	1,465,038
2012	31,189	109,034	261,248	61,545	463,016	1,928,054
2013	36,989	118,042	264,287	52,507	471,824	2,399,878
2014	35,227	125,949	271,255	43,430	475,861	2,875,740
2015	39,316	132,126	272,091	43,573	487,109	3,362,849
2016	37,446	136,026	274,132	43,664	491,268	3,854,117
2017	35,663	136,382	267,856	45,029	484,731	4,338,848
2018	33,965	139,235	261,212	45,708	480,120	4,818,968
2019	32,347	143,026	258,876	45,944	480,192	5,299,161
2020	30,807	142,449	249,970	46,459	469,686	5,768,846
2021	35,254	149,233	248,292	47,621	480,401	6,249,247
2022	33,575	156,636	252,598	46,727	489,536	6,738,783
2023	31,977	162,699	254,037	45,866	494,579	7,233,361
2024	35,017	172,807	262,918	45,746	516,488	7,749,850
2025	33,349	180,058	263,396	44,897	521,700	8,271,550
2026	34,519	186,765	262,043	44,785	528,112	8,799,661
2027	35,563	198,472	268,942	44,731	547,708	9,347,370

HEARING EXHIBIT - 00000119

	Scenario 1.9C - Conventional Expansion Scenario Without Cane Island 4					
	High Regulated CO_2 Case					
	($000, 2008$)					
	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2008	-	-	333,551	71,966	405,517	405,517
2009	-	7,359	301,976	75,271	384,607	790,124
2010	-	2,958	260,060	73,454	336,472	1,126,595
2011	15,349	3,324	273,832	59,830	352,335	1,478,930
2012	20,855	118,414	267,783	63,501	470,553	1,949,483
2013	36,555	120,459	263,889	50,948	471,852	2,421,335
2014	42,601	125,960	271,252	44,535	484,348	2,905,683
2015	40,573	132,482	272,752	43,759	489,566	3,395,248
2016	38,641	136,407	274,825	43,846	493,719	3,888,967
2017	36,801	136,761	268,325	45,201	487,088	4,376,055
2018	35,048	139,612	261,885	45,856	482,401	4,858,456
2019	33,379	143,456	259,582	46,122	482,540	5,340,997
2020	31,790	142,844	250,594	46,629	471,857	5,812,854
2021	30,276	149,714	249,048	46,893	475,932	6,288,786
2022	33,641	156,636	252,598	46,727	489,601	6,778,387
2023	32,039	162,699	254,037	45,866	494,641	7,273,029
2024	35,076	172,807	262,918	45,746	516,548	7,789,576
2025	33,406	180,058	263,396	44,897	521,757	8,311,333
2026	34,573	186,765	262,043	44,785	528,166	8,839,499
2027	35,614	198,472	268,942	44,731	547,760	9,387,259

HEARING EXHIBIT - 00000120

	Scenario 2.1A - Renewable Expansion Scenario With Cane Island 4					
	Reference Case					
	($000, 2008$)					
	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2008	-	-	333,551	71,966	405,517	405,517
2009	-	7,359	301,976	75,271	384,607	790,124
2010	-	2,946	259,301	76,312	338,561	1,128,684
2011	17,586	2,869	264,221	55,850	340,526	1,469,210
2012	32,429	3,439	237,916	114,310	388,094	1,857,304
2013	30,885	3,476	238,781	104,635	377,777	2,235,081
2014	29,414	3,504	243,508	95,688	372,114	2,607,196
2015	32,362	3,443	245,140	92,984	373,928	2,981,124
2016	30,820	3,608	246,876	90,431	371,736	3,352,860
2017	29,353	3,333	240,608	89,051	362,346	3,715,206
2018	27,955	3,445	234,393	87,249	353,042	4,068,247
2019	31,821	3,327	230,479	85,658	351,286	4,419,533
2020	30,306	3,242	221,625	84,104	339,277	4,758,810
2021	28,663	3,229	220,936	82,078	335,105	5,093,916
2022	33,251	3,369	225,708	80,335	342,662	5,436,578
2023	31,667	3,370	227,522	77,555	340,114	5,776,691
2024	30,159	3,417	237,059	75,031	345,667	6,122,359
2025	33,169	3,362	236,818	73,047	346,395	6,468,754
2026	31,589	3,311	236,149	70,814	341,863	6,810,617
2027	32,772	3,218	243,374	69,399	348,763	7,159,380

HEARING EXHIBIT - 00000121

	Scenario 2.1C - Renewable Expansion Scenario Without Cane Island 4					
	Reference Case					
	($000, 2008$)					
	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2008	-	-	333,551	71,966	405,517	405,517
2009	-	7,359	301,976	75,271	384,607	790,124
2010	-	2,948	259,301	76,312	338,561	1,128,684
2011	18,901	3,150	270,438	63,459	355,949	1,484,633
2012	18,001	3,637	243,197	118,347	383,182	1,867,815
2013	33,837	3,485	237,201	107,240	381,763	2,249,577
2014	40,013	3,479	242,009	97,711	383,211	2,632,789
2015	38,107	3,415	243,476	93,885	378,883	3,011,671
2016	36,293	3,577	245,215	91,300	376,385	3,388,056
2017	34,565	3,307	238,989	89,895	366,755	3,754,812
2018	32,919	3,417	232,786	88,075	357,197	4,112,009
2019	31,351	3,326	229,761	85,659	350,098	4,462,106
2020	29,858	3,241	220,902	84,104	338,106	4,800,213
2021	28,436	3,229	220,236	82,077	333,978	5,134,190
2022	32,845	3,370	225,037	80,333	341,584	5,475,774
2023	31,281	3,368	226,876	77,556	339,080	5,814,855
2024	29,791	3,418	236,368	75,029	344,606	6,159,461
2025	32,818	3,360	236,158	73,047	345,383	6,504,843
2026	31,255	3,310	235,505	70,814	340,884	6,845,728
2027	32,454	3,218	242,731	69,398	347,801	7,193,529

HEARING EXHIBIT - 00000122

	Scenario 2.2A - Renewable Expansion Scenario With Cane Island 4					
	Regulated CO_2 Case					
	($000, 2008$)					
	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2008	-	-	333,551	71,961	405,512	405,512
2009	-	7,359	301,976	75,268	384,603	790,115
2010	-	2,948	259,301	76,290	338,539	1,128,654
2011	17,586	2,869	264,221	55,827	340,504	1,469,157
2012	32,429	42,768	235,410	116,895	427,502	1,896,660
2013	30,885	45,285	233,809	105,862	415,841	2,312,500
2014	29,414	47,310	236,067	95,673	410,465	2,722,965
2015	33,782	48,170	238,120	92,568	412,640	3,135,605
2016	32,173	50,902	238,616	90,016	411,706	3,547,311
2017	30,641	53,171	229,337	88,879	402,028	3,949,340
2018	29,182	55,811	222,724	87,108	394,825	4,344,165
2019	31,710	59,051	220,679	85,682	397,122	4,741,287
2020	30,200	58,861	211,029	83,879	383,969	5,125,256
2021	28,762	63,103	211,139	81,878	384,883	5,510,139
2022	33,154	67,136	216,642	80,154	397,087	5,907,227
2023	31,575	71,501	216,302	77,404	396,782	6,304,009
2024	30,072	76,650	221,936	74,755	403,413	6,707,421
2025	33,085	81,841	224,388	72,763	411,877	7,119,298
2026	31,510	85,924	224,375	70,547	412,356	7,531,654
2027	32,697	93,840	226,269	69,179	421,985	7,953,639

HEARING EXHIBIT - 00000123

	Scenario 2.2C - Renewable Expansion Scenario Without Cane Island 4					
	Regulated CO_2 Case					
	($000, 2008$)					
	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2008	-	-	333,551	71,961	405,512	405,512
2009	-	7,359	301,976	75,268	384,603	790,115
2010	-	2,948	259,301	76,290	338,539	1,128,654
2011	18,901	3,150	270,438	63,445	355,935	1,484,588
2012	18,001	43,952	243,212	118,327	423,492	1,908,080
2013	33,837	45,261	233,458	107,237	419,793	2,327,874
2014	40,013	47,084	236,600	97,708	421,404	2,749,278
2015	38,107	48,063	237,355	93,634	417,160	3,166,438
2016	36,293	50,793	237,889	91,063	416,038	3,582,475
2017	34,565	53,059	228,613	89,893	406,129	3,988,605
2018	32,919	55,689	221,964	88,096	398,688	4,387,292
2019	31,351	58,923	219,997	85,683	395,954	4,783,247
2020	29,858	58,727	210,352	83,880	382,818	5,166,065
2021	28,436	62,455	211,025	81,861	383,778	5,549,842
2022	32,845	66,457	216,626	80,139	396,067	5,945,909
2023	31,281	70,799	216,320	77,388	395,788	6,341,697
2024	29,791	75,909	221,932	74,741	402,373	6,744,069
2025	32,818	80,784	224,492	72,746	410,840	7,154,909
2026	31,255	86,081	223,526	70,551	411,413	7,566,322
2027	32,454	92,830	226,418	69,165	420,867	7,987,189

HEARING EXHIBIT - 00000124

	Scenario 3.1A - DSM Expansion Scenario With Cane Island 4					
	Reference Case					
	($000, 2008$)					
	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2008	-	-	333,551	71,966	405,517	405,517
2009	-	7,357	301,897	75,698	384,952	790,469
2010	-	2,955	259,941	74,040	336,936	1,127,405
2011	17,586	2,874	264,924	53,739	339,123	1,466,529
2012	32,429	2,829	258,816	56,250	350,324	1,816,853
2013	30,885	2,861	260,491	49,626	343,863	2,160,715
2014	36,512	2,898	265,277	45,105	349,792	2,510,507
2015	34,773	2,875	266,396	44,405	348,449	2,858,956
2016	33,117	3,016	268,225	44,514	348,873	3,207,829
2017	31,540	2,793	261,882	45,846	342,061	3,549,889
2018	30,038	2,879	254,969	46,492	334,377	3,884,267
2019	28,608	2,808	251,782	46,743	329,940	4,214,207
2020	27,245	2,733	242,281	47,234	319,493	4,533,700
2021	30,882	2,684	240,050	48,106	321,723	4,855,423
2022	29,411	2,813	244,938	47,191	324,353	5,179,777
2023	32,894	2,790	245,642	46,960	328,087	5,507,863
2024	31,137	2,829	255,349	46,099	335,414	5,843,277
2025	34,100	2,783	254,741	45,869	337,492	6,180,769
2026	32,476	2,747	253,675	44,983	333,881	6,514,650
2027	33,616	2,668	260,911	44,873	342,070	6,856,720

HEARING EXHIBIT - 00000125

	Scenario 3.1C - DSM Expansion Scenario Without Cane Island 4					
	Reference Case					
	($000, 2008$)					
	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2008	-	-	333,551	71,966	405,517	405,517
2009	-	7,357	301,897	75,696	384,952	790,469
2010	-	2,955	259,941	74,040	336,936	1,127,405
2011	15,349	3,324	273,712	60,601	352,986	1,480,391
2012	20,855	3,074	266,220	60,752	350,902	1,831,293
2013	36,555	2,877	259,621	52,409	351,463	2,182,755
2014	42,601	2,868	264,281	46,034	355,784	2,538,539
2015	40,573	2,841	265,215	45,255	353,883	2,892,423
2016	38,641	2,981	266,993	45,330	353,945	3,246,368
2017	36,801	2,764	260,717	46,636	346,918	3,593,286
2018	35,048	2,847	253,838	47,268	339,002	3,932,287
2019	33,379	2,776	250,560	47,461	334,176	4,266,464
2020	31,790	2,705	241,205	47,955	323,654	4,590,118
2021	30,276	2,684	240,045	48,112	321,118	4,911,236
2022	28,834	2,813	244,938	47,191	323,777	5,235,013
2023	32,144	2,790	245,642	46,961	327,538	5,562,551
2024	30,614	2,829	255,349	46,099	334,891	5,897,442
2025	33,601	2,783	254,741	45,870	336,994	6,234,437
2026	32,001	2,747	253,675	44,983	333,407	6,567,843
2027	33,164	2,668	260,911	44,873	341,618	6,909,461

HEARING EXHIBIT - 00000126

	Scenario 3.2A - DSM Expansion Scenario With Cane Island 4					
	Regulated CO_2 Case					
	($000, 2008$)					
	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2008	-	-	333,551	71,961	405,512	405,512
2009	-	7,357	301,897	75,695	384,950	790,462
2010	-	2,955	259,941	74,017	336,913	1,127,375
2011	17,586	2,874	264,924	53,716	339,101	1,466,476
2012	32,429	44,622	256,082	59,173	392,306	1,858,781
2013	30,885	47,398	254,851	51,076	384,210	2,242,991
2014	36,512	49,554	259,160	45,102	390,327	2,633,318
2015	34,773	50,937	258,683	44,211	388,804	3,022,122
2016	33,117	53,819	259,354	44,352	390,642	3,412,764
2017	31,540	56,049	250,249	45,870	383,708	3,796,473
2018	30,038	58,839	242,879	46,584	378,340	4,174,813
2019	28,608	62,317	240,819	46,841	378,586	4,553,398
2020	27,245	62,566	229,806	47,117	366,735	4,920,133
2021	30,882	66,792	228,652	47,991	374,317	5,294,450
2022	29,411	70,965	234,219	47,069	381,663	5,676,113
2023	32,694	75,307	232,667	46,832	387,499	6,063,612
2024	31,137	81,043	237,703	45,863	395,765	6,459,377
2025	34,100	86,275	240,145	45,647	406,166	6,865,543
2026	32,476	90,922	239,808	44,774	407,980	7,273,523
2027	33,616	99,160	241,418	44,708	418,902	7,692,426

HEARING EXHIBIT - 00000127

	Scenario 3.2C - DSM Expansion Scenario Without Cane Island 4					
	Regulated CO_2 Case					
	($000, 2008$)					
	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2008	-	-	333,551	71,961	405,512	405,512
2009	-	7,357	301,897	75,695	384,950	790,462
2010	-	2,955	259,941	74,017	336,913	1,127,375
2011	15,349	3,324	273,712	60,585	352,970	1,480,345
2012	20,855	46,153	266,309	60,739	394,056	1,874,401
2013	36,555	47,457	255,042	52,808	391,862	2,266,263
2014	42,601	49,372	258,185	46,032	396,191	2,662,454
2015	40,573	50,714	257,742	45,066	394,095	3,056,549
2016	38,641	53,579	258,180	45,159	395,559	3,452,108
2017	36,801	55,819	249,141	46,651	388,411	3,840,519
2018	35,048	58,600	241,821	47,318	382,787	4,223,306
2019	33,379	62,046	239,670	47,515	382,610	4,605,916
2020	31,790	62,311	228,808	47,798	370,708	4,976,623
2021	30,276	66,792	228,652	47,991	373,711	5,350,334
2022	28,834	70,965	234,219	47,069	381,086	5,731,421
2023	32,144	75,307	232,667	46,832	386,950	6,118,370
2024	30,614	81,043	237,703	45,883	395,242	6,513,612
2025	33,601	86,275	240,145	45,647	405,669	6,919,281
2026	32,001	90,922	239,808	44,774	407,506	7,326,786
2027	33,164	99,160	241,418	44,708	418,451	7,745,237

HEARING EXHIBIT - 00000128

	Scenario 4.1A - DSM Expansion Scenario With Cane Island 4					
	Reference Case					
	($000, 2008$)					
	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2008	-	-	333,551	71,966	405,517	405,517
2009	-	7,357	301,897	75,698	384,952	790,469
2010	-	2,946	259,183	76,897	339,026	1,129,495
2011	17,586	2,867	264,128	56,632	341,213	1,470,708
2012	24,952	3,438	237,841	114,118	380,349	1,851,057
2013	31,049	3,475	238,648	105,570	378,741	2,229,799
2014	29,570	3,503	243,365	96,679	373,116	2,602,915
2015	28,162	3,443	244,985	93,041	369,631	2,972,546
2016	32,441	3,577	245,821	91,312	373,151	3,345,697
2017	30,896	3,307	239,590	89,884	363,677	3,709,373
2018	29,425	3,417	233,413	88,041	354,296	4,063,669
2019	28,024	3,326	230,322	85,613	347,285	4,410,954
2020	26,689	3,241	221,484	84,034	335,449	4,746,402
2021	31,332	3,228	220,774	82,905	338,240	5,084,642
2022	29,840	3,368	225,555	80,206	338,970	5,423,612
2023	28,419	3,369	227,362	77,420	336,570	5,760,182
2024	31,629	3,389	236,002	75,543	346,562	6,106,744
2025	30,123	3,361	238,662	72,882	343,028	6,449,772
2026	31,953	3,311	235,997	71,450	342,711	6,792,483
2027	30,431	3,231	243,524	69,336	346,522	7,139,005

HEARING EXHIBIT - 00000129

	Scenario 4.1C - DSM Expansion Scenario Without Cane Island 4					
	Reference Case					
	($000, 2008$)					
	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2008	-	-	333,551	71,966	405,517	405,517
2009	-	7,357	301,897	75,698	384,952	790,469
2010	-	2,946	259,183	76,897	339,026	1,129,495
2011	15,349	3,315	272,767	63,479	354,910	1,484,406
2012	14,618	3,715	245,211	118,491	382,035	1,866,441
2013	30,615	3,512	238,603	107,188	379,917	2,246,358
2014	36,944	3,503	243,353	97,755	381,555	2,627,913
2015	35,185	3,443	244,975	94,031	377,633	3,005,545
2016	33,510	3,607	246,698	91,471	375,285	3,380,830
2017	31,914	3,332	240,428	90,039	365,712	3,746,543
2018	30,394	3,443	234,215	88,193	356,246	4,102,788
2019	28,947	3,354	231,208	85,766	349,274	4,452,063
2020	27,568	3,266	222,257	84,181	337,273	4,789,336
2021	26,256	3,257	221,714	82,168	333,395	5,122,731
2022	29,812	3,370	225,585	80,204	338,971	5,461,701
2023	28,393	3,369	227,424	77,419	336,604	5,798,306
2024	31,603	3,389	236,061	75,543	346,596	6,144,901
2025	30,098	3,361	236,718	72,882	343,060	6,487,961
2026	31,929	3,313	236,075	71,447	342,765	6,830,725
2027	30,409	3,233	243,645	69,333	346,620	7,177,345

HEARING EXHIBIT - 00000130

	Scenario 4.2A - DSM Expansion Scenario With Cane Island 4					
	Regulated CO_2 Case					
	($000, 2008$)					
	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2008	-	-	333,551	71,961	405,512	405,512
2009	-	7,357	301,897	75,695	384,950	790,462
2010	-	2,946	259,183	76,876	339,005	1,129,467
2011	17,586	2,867	264,128	56,611	341,192	1,470,659
2012	24,952	42,746	235,330	116,684	419,712	1,890,371
2013	31,049	45,267	233,677	106,798	416,792	2,307,163
2014	29,570	47,291	237,927	96,664	411,452	2,718,615
2015	28,162	48,304	238,809	92,776	408,051	3,126,666
2016	32,441	50,877	238,463	91,063	412,843	3,539,509
2017	30,896	53,146	229,186	89,874	403,102	3,942,611
2018	29,425	55,786	222,580	88,056	395,846	4,338,457
2019	28,024	59,018	220,533	85,631	393,206	4,731,663
2020	26,689	58,828	210,901	83,806	380,223	5,111,886
2021	31,332	63,071	210,985	82,718	388,106	5,499,992
2022	29,840	67,101	216,500	80,021	393,462	5,893,454
2023	28,419	71,461	216,156	77,264	393,300	6,286,754
2024	31,629	76,328	220,984	75,227	404,168	6,690,923
2025	30,123	81,600	224,245	72,594	408,562	7,099,485
2026	33,019	85,620	223,589	70,991	413,219	7,512,704
2027	31,447	93,597	225,637	68,898	419,579	7,932,283

HEARING EXHIBIT - 00000131

	Scenario 4.2C - DSM Expansion Scenario Without Cane Island 4 Regulated CO_2 Case ($000, 2008$)					
	Present Worth of Capital Costs	Present Worth of Environmental Costs	Present Worth of Fuel Costs	Present Worth of Other Costs	Present Worth of Total Costs	Cum. Present Worth of Total Costs
2008	-	-	333,551	71,961	405,512	405,512
2009	-	7,357	301,897	75,695	384,950	790,462
2010	-	2,946	259,183	76,876	339,005	1,129,467
2011	15,349	3,315	272,767	63,464	354,895	1,484,361
2012	14,618	44,293	245,227	118,470	422,608	1,906,970
2013	30,615	45,430	234,446	107,605	418,096	2,325,066
2014	36,944	47,297	237,914	97,752	419,906	2,744,972
2015	35,185	48,312	238,807	93,783	416,086	3,161,059
2016	33,510	51,057	239,320	91,225	415,112	3,576,170
2017	31,914	53,323	229,986	90,034	405,257	3,981,427
2018	30,394	55,966	223,331	88,251	397,942	4,379,369
2019	28,947	59,227	221,364	85,829	395,367	4,774,736
2020	27,568	59,023	211,616	83,994	382,201	5,156,937
2021	26,256	63,309	211,862	82,017	383,445	5,540,382
2022	29,812	67,101	216,539	80,020	393,473	5,933,855
2023	28,393	71,463	216,217	77,261	393,333	6,327,188
2024	31,603	76,328	221,043	75,228	404,202	6,731,390
2025	30,098	81,602	224,326	72,592	408,618	7,140,008
2026	32,996	85,621	223,698	70,989	413,304	7,553,312
2027	31,425	93,597	225,761	68,898	419,682	7,972,994

HEARING EXHIBIT - 00000132

Attachment 50

FMPA's Response to the Staff's 4th Set of Interrogatories

Table 50.A: Reserve Margin Analysis with Cane Island Unit 4

Summer

August of the Year	(1)[1] Resource Plan Changes	(2) Current Projections of FMPA Unit Capability (MW)	(3)[2] Current Projections of Firm Purchases (MW)	(4) Cumulative Generation Additions from Plan (MW)	(5) Cumulative Generation Removed from Plan (MW)	(6) = (2)+(3)+(4)+(5) Projection of Total Capacity (MW)	(7) Peak Load Forecast (MW)	(8)[3] Summer DSM Forecast (MW)	(9)=(7)-(8) Forecast of Firm Peak (MW)	(10)=(6)-(9) Forecast of Summer Reserves (MW)	(11)=(10)/(9) Forecast of Summer Reserve Margin (%)	(12)=((7)-(8))/((8)-(#)) BV Forecast of Summer Reserve Margin (%)
2007	-	-	-	-	-	-	-	-	-	-	-	-
2008		1318	412	296	(114)	1912	1545	-	1545	367	23.75%	24.97%
2009	Calpine Purchase Terminated	1318	457	296	(114)	1957	1593	-	1593	364	22.85%	24.71%
2010	PEF Purchase Terminated	1318	402	296	(300)	1716	1483	-	1483	233	15.71%	17.68%
2011	Cane Island 4	1318	282	596	(389)	1807	1527	-	1527	280	18.34%	18.89%
2012	7FA CT	1318	282	745	(426)	1919	1560	-	1560	359	23.01%	23.70%
2013	7FA CT & FPL Purchase Terminated	1318	237	894	(426)	2023	1594	-	1594	429	26.91%	26.91%
2014		1318	237	894	(426)	2023	1630	-	1630	393	24.11%	24.11%
2015		1318	237	894	(426)	2023	1668	-	1668	355	21.28%	21.28%
2016	Nuclear 1	1318	237	922	(426)	2051	1705	-	1705	346	20.29%	20.29%
2017	Nuclear 2	1318	237	950	(426)	2079	1744	-	1744	335	19.21%	19.21%
2018	Nuclear 3	1318	237	1000	(426)	2129	1782	-	1782	347	19.47%	19.47%
2019	LMS100	1318	237	1086	(426)	2215	1820	-	1820	395	21.70%	21.70%
2020	Nuclear 4	1318	237	1136	(426)	2265	1859	-	1859	406	21.84%	21.84%
2021		1318	237	1136	(426)	2265	1898	-	1898	367	19.34%	19.34%
2022	LMS100	1318	237	1222	(426)	2351	1938	-	1938	413	21.31%	21.31%
2023		1318	237	1222	(426)	2351	1978	-	1978	373	18.86%	18.86%
2024	LMS100	1318	237	1308	(426)	2437	2018	-	2018	419	20.76%	20.76%
2025		1318	237	1308	(426)	2437	2057	-	2057	380	18.47%	18.47%
2026	LMS6000	1318	237	1354	(426)	2483	2098	-	2098	385	18.35%	18.35%
2027	LMS6000	1318	237	1400	(426)	2529	2139	-	2139	390	18.23%	18.23%

1 - Details Regarding Purchase Power Contracts can be found in Section 3.3 of the NFP Application
2 - Includes Non-Partial & Partial Purchase Requirements
3 - DSM Forecast is Included in Peak Load Forecast
- Partial Purchase Requirments (MW) as presented in Table 13-1 of the NFP Application

HEARING EXHIBIT - 00000134

Attac nt for Staff's Fourth Set of Interrogatories Question 50b
Docke No. 080253-EI
Reserve Margin Analysis

Table 50.B: Reserve Margin Analysis without Cane Island Unit 4

August of the Year	(1)[1] Resource Plan Changes	(2) Projections of FMPA Unit Capability (MW)	(3)[2] Current Projections of Firm Purchases (MW)	(4) Cumulative Generation Additions from Plan (MW)	(5) Cumulative Generation Removed from Plan (MW)	(6) = (2)+(3) +(4)+(5) Projection of Total Capacity (MW)	(7) Peak Load Forecast (MW)	(8)[3] Summer DSM Forecast (MW)	(9)=(7)-(8) Forecast of Firm Peak (MW)	(10)=(6)-(9) Forecast of Summer Reserves (MW)	(11)=(10)/(9) Forecast of Summer Reserve Margin (%)	(12)=((7)-(8))/((8)-(#)) BV Forecast of Summer Reserve Margin (%)
					Summer							
2007	-	-	-	-	-	-	-	-	-	-	-	-
2008		1318	412	296	(114)	1912	1545	-	1545	367	23.75%	24.97%
2009	Calpine Purchase Terminated	1318	457	296	(114)	1957	1593	-	1593	364	22.85%	24.71%
2010	PEF Purchase Terminated	1318	402	296	(300)	1716	1483	-	1483	233	15.71%	17.68%
2011	7FA CT	1318	282	594	(389)	1805	1527	-	1527	278	18.21%	18.76%
2012	LMS100	1318	282	680	(426)	1854	1560	-	1560	294	18.85%	19.41%
2013	7FA 1x1 CC & FPL Purchase Terminated	1318	237	980	(426)	2109	1594	-	1594	515	32.31%	32.31%
2014		1318	237	980	(426)	2109	1630	-	1630	479	29.39%	29.39%
2015		1318	237	980	(426)	2109	1668	-	1668	441	26.44%	26.44%
2016	Nuclear 1	1318	237	1008	(426)	2137	1705	-	1705	432	25.34%	25.34%
2017	Nuclear 2	1318	237	1036	(426)	2165	1744	-	1744	421	24.14%	24.14%
2018	Nuclear 3	1318	237	1086	(426)	2215	1782	-	1782	433	24.30%	24.30%
2019		1318	237	1086	(426)	2215	1820	-	1820	395	21.70%	21.70%
2020	Nuclear 4	1318	237	1136	(426)	2265	1859	-	1859	406	21.84%	21.84%
2021		1318	237	1136	(426)	2265	1898	-	1898	367	19.34%	19.34%
2022	LMS100	1318	237	1222	(426)	2351	1938	-	1938	413	21.31%	21.31%
2023		1318	237	1222	(426)	2351	1978	-	1978	373	18.86%	18.86%
2024	LMS100	1318	237	1308	(426)	2437	2018	-	2018	419	20.76%	20.76%
2025		1318	237	1308	(426)	2437	2057	-	2057	380	18.47%	18.47%
2026	LMS6000	1318	237	1354	(426)	2483	2098	-	2098	385	18.35%	18.35%
2027	LMS6000	1318	237	1400	(426)	2529	2139	-	2139	390	18.23%	18.23%

1 - Details Regarding Purchase Power Contracts can be found in Section 3.3 of the NFP Application
2 - Includes Non-Partial & Partial Purchase Requirements
3 - DSM Forecast is Included in Peak Load Forecast
- Partial Purchase Requirments (MW) as presented in Table 13-1 of the NFP Application

HEARING EXHIBIT - 00000135

Attac[illegible]t for Staff's Fourth Set of Interrogatories Question 50c
Docke[illegible]o. 080283-EI
Reserve Margin Analysis

Table 50.C: Reserve Margin Analysis with Cane Island Unit 4

Winter

January of the Year	(1)[1] Resource Plan Changes	(2) Current Projections of FMPA Unit Capability (MW)	(3)[2] Current Projections of Firm Purchases (MW)	(4) Cumulative Generation Additions from Plan (MW)	(5) Cumulative Generation Removed from Plan (MW)	(6) = (2)+(3)+(4)+(5) Projection of Total Capacity (MW)	(7) Peak Load Forecast (MW)	(8)[3] Summer DSM Forecast (MW)	(9)=(7)-(8) Forecast of Firm Peak (MW)	(10)=(6)-(9) Forecast of Summer Reserves (MW)	(11)=(10)/(9) Forecast of Summer Reserve Margin (%)	(12)=((7)-(8))/((8)-(#)) BV Forecast of Summer Reserve Margin (%)
2007	-	-	-	-	-	-	-	-	-	-	-	-
2008		1386	417	0	6	1,809	1427	-	1427	382	26.77%	28.25%
2009	Calpine Purchase Terminated	1386	462	318	(108)	2,058	1473	-	1473	585	39.71%	43.24%
2010	PEF Purchase Terminated	1386	407	318	(307)	1,804	1342	-	1342	462	34.43%	39.25%
2011		1386	287	318	(307)	1,684	1382	-	1382	302	21.85%	22.59%
2012	Cane Island 4 & 7FA CT	1386	287	783	(395)	2,041	1412	-	1412	629	44.55%	46.01%
2013	7FA CT & FPL Purchase Terminated	1386	287	940	(440)	2,173	1444	-	1444	729	50.48%	50.48%
2014		1386	242	940	(440)	2,128	1476	-	1476	652	44.17%	44.17%
2015		1386	242	940	(440)	2,128	1510	-	1510	618	40.93%	40.93%
2016		1386	242	940	(440)	2,128	1545	-	1545	583	37.73%	37.73%
2017	Nuclear 1 & Nuclear 2	1386	242	996	(440)	2,184	1579	-	1579	605	38.32%	38.32%
2018		1386	242	996	(440)	2,184	1614	-	1614	570	35.32%	35.32%
2019	Nuclear 3 & LMS100	1386	242	1142	(440)	2,330	1649	-	1649	681	41.30%	41.30%
2020		1386	242	1142	(440)	2,330	1684	-	1684	646	38.36%	38.36%
2021	Nuclear 4	1386	242	1192	(440)	2,380	1720	-	1720	660	38.37%	38.37%
2022	LMS100	1386	242	1288	(440)	2,476	1756	-	1756	720	41.00%	41.00%
2023		1386	242	1288	(440)	2,476	1792	-	1792	684	38.17%	38.17%
2024	LMS100	1386	242	1384	(440)	2,572	1828	-	1828	744	40.70%	40.70%
2025		1386	242	1384	(440)	2,572	1865	-	1865	707	37.91%	37.91%
2026	LM6000	1386	242	1431	(440)	2,619	1901	-	1901	718	37.77%	37.77%
2027	LM6000	1386	242	1478	(440)	2,666	1938	-	1938	728	37.56%	37.56%

1 - Details Regarding Purchase Power Contracts can be found in Section 3.3 of the NFP Application
2 - Includes Non-Partial & Partial Purchase Requirements
3 - DSM Forecast is Included in Peak Load Forecast
- Partial Purchase Requirments (MW) as presented in Table 13-1 of the NFP Application

HEARING EXHIBIT - 00000136

Attachment for Staff's Fourth Set of Interrogatories Question 50d
Docket No. 080253-EI
Reserve Margin Analysis

Table 50.D: Reserve Margin Analysis without Cane Island Unit 4

Winter

January of the Year	(1)[1] Resource Plan Changes	(2) Current Projections of FMPA Unit Capability (MW)	(3)[2] Current Projections of Firm Purchases (MW)	(4) Cumulative Generation Additions from Plan (MW)	(5) Cumulative Generation Removed from Plan (MW)	(6) = (2)+(3)+(4)+(5) Projection of Total Capacity (MW)	(7) Peak Load Forecast (MW)	(8)[3] Summer DSM Forecast (MW)	(9)=(7)-(8) Forecast of Firm Peak (MW)	(10)=(6)-(9) Forecast of Summer Reserves (MW)	Forecast of Summer Reserve Margin (%)	(12)=((7)-(8))/((8)-(#)) BV Forecast of Summer Reserve Margin (%)
2007	-	-	-	-	-	-	-	-	-	-	-	-
2008		1386	417		6	1,809	1427	-	1427	382	26.77%	26.25%
2009	Calpine Purchase Terminated	1386	462	318	(108)	2,058	1473	-	1473	585	39.71%	43.24%
2010	PEF Purchase Terminated	1386	407	318	(307)	1,804	1342	-	1342	462	34.43%	39.25%
2011	7FA CT & 7FA CT	1386	287	672	(307)	2,038	1382	-	1382	656	47.47%	49.07%
2012	LMS100	1386	287	768	(395)	2,046	1412	-	1412	634	44.90%	46.38%
2013	7FA 1x1 CC & FPL Purchase Terminated	1386	287	1,036	(440)	2,269	1444	-	1444	825	57.13%	57.13%
2014		1386	242	1,036	(440)	2,224	1476	-	1476	748	50.68%	50.68%
2015		1386	242	1,036	(440)	2,224	1510	-	1510	714	47.28%	47.28%
2016		1386	242	1,036	(440)	2,224	1545	-	1545	679	43.95%	43.95%
2017	Nuclear 1 & Nuclear 2	1386	242	1,092	(440)	2,280	1579	-	1579	701	44.40%	44.40%
2018		1386	242	1,092	(440)	2,280	1614	-	1614	666	41.26%	41.26%
2019	Nuclear 3	1386	242	1,142	(440)	2,330	1649	-	1649	681	41.30%	41.30%
2020		1386	242	1,142	(440)	2,330	1684	-	1684	646	38.36%	38.36%
2021	Nuclear 4	1386	242	1,192	(440)	2,380	1720	-	1720	660	38.37%	38.37%
2022	LMS100	1386	242	1,288	(440)	2,476	1756	-	1756	720	41.00%	41.00%
2023		1386	242	1,288	(440)	2,476	1792	-	1792	684	38.17%	38.17%
2024	LMS100	1386	242	1,384	(440)	2,572	1828	-	1828	744	40.70%	40.70%
2025		1386	242	1,384	(440)	2,572	1865	-	1865	707	37.91%	37.91%
2026	LM6000	1386	242	1,431	(440)	2,619	1901	-	1901	718	37.77%	37.77%
2027	LM6000	1386	242	1,478	(440)	2,666	1938	-	1938	728	37.56%	37.56%

1 - Details Regarding Purchase Power Contracts can be found in Section 3.3 of the NFP Application
2 - Includes Non-Partial & Partial Purchase Requirements
3 - DSM Forecast is Included in Peak Load Forecast
- Partial Purchase Requirments (MW) as presented in Table 13-1 of the NFP Application

HEARING EXHIBIT - 00000137

5

FMPA's Responses to Staff's Fifth Set of Interrogatories (Nos. 51-53)

HEARING EXHIBIT - 00000138

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition to determine need for Cane Island Power Park Unit 4 electrical power plant in Osceola County, by Florida Municipal Power Agency.	DOCKET NO. 080253-EM DATED: JULY 21, 2008

FLORIDA MUNICIPAL POWER AGENCY RESPONSES TO STAFF'S FIFTH SET OF INTERROGATORIES (NOS. 51 - 53)

Florida Municipal Power Agency (FMPA) pursuant to Rule 28-106.206, Florida Administrative Code (F.A.C.), and Rule 1.340, Florida Rules of Civil Procedure, hereby responds to Staffs Fifth Set of Interrogatories (Nos. 51-53).

INTERROGATORIES & RESPONSES

51. Please refer to page 12, lines 10 - 18, of the direct testimony of Witness Kushner and to Exhibit BEK-5. Please state whether FMPA assigns any weights or probabilities to the CO_2 cases included in its cost-effective analysis.

a. If your response is yes, please explain or describe what weights or probabilities FMPA assigns to each case.

b. If your response is no, please explain why FMPA does not assign any weights or probabilities to the alternative cases of CO_2 price forecast.

Response:

a. FMPA has not assigned any weights or probabilities to the CO_2 cases included in its cost-effective analysis.

b. As illustrated in Table 5 of Exhibit __[BEK-5] to Witness Kushner's testimony, the expansion plans including operation of the proposed Cane Island 4 generating unit beginning in 2011 represent the most cost-effective expansion plans for all of the CO_2 emissions scenarios considered. As a result, FMPA did not consider it

necessary to perform a probabilistic analysis to supplement the evaluations included in the Cane Island 4 Need for Power Application.

52. Please refer to page 13, lines 13 - 15, of the direct testimony of Witness Kushner and to Exhibit BEK-5. Please respond to the following:

a. Please explain or describe how the $22 million amount was derived.

b. Please explain or describe how the $81 million amount was derived.

c. Please explain or describe how the two amounts in b and c relate to the figures presented in Table 5 through Table 8 of Exhibit BEK-5, attached to the direct testimony of Witness Kushner.

Response:

a. The $22 million amount is the approximate cumulative present worth costs (CPWC) savings associated with the High Load case described in Section 20.1.1.4 of the Cane Island 4 Need for Power Application. The methodology utilized in evaluation of the High Load Case is the same as that outlined in Section 19 of the Cane Island 4 Need for Power Application and described throughout the direct testimony of Witness Kushner.

b. The $81 million amount is the approximate cumulative present worth costs (CPWC) savings associated with the Low Load case described in Section 20.1.1.5 of the Cane Island 4 Need for Power Application. The methodology utilized in evaluation of the Low Load Case is the same as that outlined in Section 19 of the Cane Island 4 Need for Power Application and described throughout the direct testimony of Witness Kushner.

c. The $22 million and $81 million figures represent the case scenarios with lowest and highest CPWC savings, respectively, of all the modeling scenarios included in the Cane Island 4 Need for Power Application. The two figures are referenced in Mr. Kushner's testimony to provide the range of modeling results for the various scenarios.

The $22 million figure is a rounded number that corresponds to the value from the "CPWC Savings for Expansion Plan with Cane Island 4 in 2011" column of Table 5 *(CPWC Summaries for Scenario 1 – Conventional Expansion* Scenario) of Exhibit __[BEK-5] to Witness Kushner's testimony for the "High Load" case.

The $81 million figure is a rounded number that corresponds to the value from the "CPWC Savings for Expansion Plan with Cane Island 4 in 2011" column of Table 5 *(CPWC Summaries for Scenario 1 – Conventional Expansion* Scenario) of Exhibit __[BEK-5] to Witness Kushner's testimony for the "Low Load" case.

53. **Please state whether FMPA has considered the potential influences of different CO_2 prices (or CO_2 legislations) on the SO_2 and NOx price forecasts in conducting its cost-effectiveness analysis.**

a. **If your response is yes, please explain or describe how FMPA considered the potential CO_2 legislations on the SO_2 and NOx price forecasts in conducting its cost-effectiveness analysis.**

b. **If your response is no, please explain why not.**

Response:

a. FMPA has not considered the potential influences of different CO_2 prices (or CO_2 legislations) on the SO_2 and NOx price forecasts in conducting its cost-effectiveness analysis.

b. Integrated SO_2 and NO_x emissions allowance price projections corresponding to the EIA analysis of S.280 (which was used as the basis for the *Regulated CO_2 Case* and the *High Fuel with Regulated CO_2 Case* evaluated in the Cane Island 4 Need for Power Application) and the EPA's analysis of S.2191 (which was used as the basis for the *High Regulated CO_2 Case* evaluated in the Cane Island 4 Need for Power Application) were not available. As a result, the *Regulated CO_2 Case and the High Regulated CO_2 Case* both included SO_2 and NO_x emissions allowance prices corresponding to the AEO2007 Reference Case, and the *High Fuel Price with Regulated CO_2 Case* included SO_2 and NO_x emissions allowance prices corresponding to the AEO2007 High Price Case.

As a natural gas combined cycle generating unit, the costs of SO_2 and NO_x emissions have a very minor impact on the relative economics of Cane Island 4 due to its low emissions rates for both SO_2 and NO_x. FMPA therefore did not believe it was necessary to develop any SO_2 and NO_x emissions allowance price projections specifically for inclusion in the evaluations of the regulated CO_2 cases.

All of the foregoing answers to Staff's Fifth Set of Interrogatories (Nos. 51-53) were provided by Bradley Kushner (consultant to FMPA), Black & Veatch Corporation, 11401 Lamar Avenue, Overland Park, Kansas 66211.

Dated this 25th day of July, 2008.

HOPPING GREEN & SAMS, P.A.

By: _____
Gary V. Perko
123 S. Calhoun Street
Tallahassee, FL 32314
(850) 222-7500 (telephone)
(850) 224-8551 (facsimile)
Email: GPerko@hgslaw.com

Attorneys for Florida Municipal Power Agency

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF LEON)

I hereby certify that on this 21st day of July, 2008, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Bradley E. Kushnee, who is personally known to me, and he/she acknowledged before me that he/she provided the answers to interrogatory number(s) 51-53 from STAFF'S SIXTH FIFTH OF INTERROGATORIES (NOS. 51-53) in Docket No. 080253-EM, and that the responses are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 21st day of July, 2008.

Bradley E Kushnee

Rebecca J Emerson
Notary Public
State of Florida at Large

Rebecca J. Emerson
Commission # DD617747
Expires January 15, 2011
Bonded Thru Fain Insurance, Inc 800-385-7019

My Commission Expires:

_____

6

FMPA's Responses to Staff's Sixth Set of Interrogatories (No. 54)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition to determine need for Cane Island Power Park Unit 4 electrical power plant in Osceola County, by Florida Municipal Power Agency.	DOCKET NO. 080253-EM DATED: JULY 21, 2008

FLORIDA MUNICIPAL POWER AGENCY RESPONSES TO STAFF'S SIXTH SET OF INTERROGATORIES (NO. 54)

Florida Municipal Power Agency (FMPA) pursuant to Rule 28-106.206, Florida Administrative Code (F.A.C.), and Rule 1.340, Florida Rules of Civil Procedure, hereby responds to Staffs Sixth Set of Interrogatories (No. 54).

INTERROGATORIES & RESPONSES

54. Please discuss the status of the negotiations with ESCO provider, discussed in Witness Guarriello's testimony.

Response:

On June 26, 2008, the FMPA Executive Committee approved a Master Marketing Agreement ("Agreement") between the Florida Municipal Power Agency ("All-Requirements Power Supply Project") and Energy Systems Group, LLC ("ESG"). The Agreement has been signed by both parties. ESG is an energy services company in the business of rendering professional, performance, construction, operation and maintenance services, and facilities management to commercial, government and industrial customers in the State of Florida.

All of the foregoing answer to Staff's Sixth Set of Interrogatories (Nos. 54) were provided by Nicholas Guarriello (consultant to FMPA), R.W.Beck, 100 Legion Place, Suite 1100, Orlando, Florida 32801.

Dated this 21st day of July, 2008.

HOPPING GREEN & SAMS, P.A.

By: _____

Gary V. Perko
123 S. Calhoun Street
Tallahassee, FL 32314
(850) 222-7500 (telephone)
(850) 224-8551 (facsimile)
Email: GPerko@hgslaw.com

Attorneys for Florida Municipal Power Agency

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF ORANGE

I hereby certify that on this 21st day of July, 2008, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Nicholas P. Guarriello, who is personally known to me, and he/she acknowledged before me that he/she provided the answers to interrogatory number(s) 54 from STAFF'S SIXTH SET OF INTERROGATORIES (NO. 54) in Docket No. 080253-EM, and that the responses are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 21st day of July, 2008.

Nicholas P. Guarriello

Notary Public
State of Florida, at Large

My Commission Expires:

Notary Public State of Florida
Thaddeus Szymanldewicz
My Commission DD541922
Expires 06/30/2010

7

FMPA's Response to Staff's First Request for Production of Documents (Nos. 1-3)

HEARING EXHIBIT - 00000149

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition to determine need for Cane Island Power Park Unit 4 electrical power plant in Osceola County, by Florida Municipal Power Agency.	DOCKET NO. 080253-EM DATED: June 19, 2008

FLORIDA MUNICIPAL POWER AGENCY RESPONSES TO
STAFF'S FIRST REQUEST FOR PRODUCTION DOCUMENTS (NOS. 1-3)

Florida Municipal Power Agency (FMPA) pursuant to Rule 28-106.26, Florida Administrative Code, and Rule 1.350, Florida Rules of Civil Procedure, hereby responds to Staff's First Request for Production of Documents (Nos. 1-3).

DOCUMENTS REQUESTED

1. **Please refer to FMPA's Need for Power Application. Please provide the source documents for each of the following tables and figures presented in Section 7.0, Fuel and Emissions Allowance Price Projections, sponsored by Witness Kushner:**

   a. **Table 7-7 "Annual Energy Outlook 2007 Reference Case Price Projections Forecast of Emissions Allowance Prices for CAIR-Regulated Emissions" presented on page 7-23;**

Response to POD 1a
Attachment POD-1.a presents the source of Table 7-7, the AEO2007 Table 117 National Impacts of the Clean Air Amendments of 1990 (CAAA90) Reference Case. Table 117 was provided by the EIA directly to Black & Veatch.

   b. **Table 7-8 "Annual Energy Outlook 2007 High Case Price Projections Forecast of Emissions Allowance Prices for CAIR-Regulated Emissions" presented on page 7-25;**

Response to POD 1b
Attachment POD-1.bc presents the source of Table 7-8, the AEO2007 Table 117 National Impacts of the Clean Air Act of 1990 (CAAA90) High Price Case. Table 117 was provided by the EIA directly to Black & Veatch.

   c. **Table 7-9 "Annual Energy Outlook 2007 Low Case Price Projections Forecast of Emissions Allowance Prices for CAIR-Regulated Emissions" presented on page 7-26;**

HEARING EXHIBIT 00000150

Response to POD 1c
Attachment POD-1.bc presents the source of Table 7-9, the AEO2007 Table 117 National Impacts of the Clean Air Act of 1990 (CAAA90) Low Price Case. Table 117 was provided by the EIA directly to Black & Veatch.

d. Table 7-10 "Natural Gas Price Projections for AEO2007 Reference Case and EIA Analysis of S.280" presented on page 7-31;

Response to POD 1d
Attachment POD-1.d presents the source of Table 7-10, which is *Table 13 Natural Gas Supply, Disposition, and Prices* for the referenced cases. The Reference Case table is located at http://www.eia.doe.gov/oiaf/archive/aeo07/excel/aeotab_13.xls; the cases associated with the EIA's analysis of S.280 are located at http://www.eia.doe.gov/oiaf/servicerpt/csia/ and at http://www.eia.doe.gov/oiaf/servicerpt/biv/index.html.

e. Table 7-11 "Distillate Fuel Oil Price Projections for AEO2007 Reference Case and EIA Analysis of S.280" presented on page 7-32;

Response to POD 1e
Attachment POD-1.ef presents the source of Table 7-11, which is *Table 12 Petroleum Product Prices* for the referenced cases. The Reference Case table is located at http://www.eia.doe.gov/oiaf/archive/aeo07/excel/aeotab_12.xls; the cases associated with the EIA's analysis of S.280 are located at http://www.eia.doe.gov/oiaf/servicerpt/csia/ and at http://www.eia.doe.gov/oiaf/servicerpt/biv/index.html.

f. Table 7-12 "Residual Fuel Oil Price Projections for AEO2007 Reference Case and EIA Analysis of S.280" presented on page 7-33;

Response to POD 1f
Attachment POD-1.ef presents the source of Table 7-11, which is *Table 12 Petroleum Product Prices* for the referenced cases. The Reference Case table is located at http://www.eia.doe.gov/oiaf/archive/aeo07/excel/aeotab_12.xls; the cases associated with the EIA's analysis of S.280 are located at http://www.eia.doe.gov/oiaf/servicerpt/csia/ and at http://www.eia.doe.gov/oiaf/servicerpt/biv/index.html.

g. Table 7-13 "Coal Price Projections for AEO2007 Reference Case and EIA Analysis of S.280" presented on page 7-34;

Response to POD 1g
Attachment POD-1.g presents the source of Table 7-13, which is *Table 15 Coal Supply, Disposition, and Prices* for the referenced cases. The Reference Case table is located at http://www.eia.doe.gov/oiaf/archive/aeo07/excel/aeotab_15.xls; the cases associated with the

HEARING EXHIBIT - 00000151

EIA's analysis of S.280 are located at http://www.eia.doe.gov/oiaf/servicerpt/csia/ and at http://www.eia.doe.gov/oiaf/servicerpt/biv/index.html.

h. Table 7-14 "CO_2 Emission Allowance Price Projections from EIA Analysis of S.280" presented on page 7-35;

Response to POD 1h
Attachment POD-1.h presents the source of Table 7-14, which is *Table 21 Greenhouse Gas Emission Results* for the referenced cases. The tables for all the cases are located at http://www.eia.doe.gov/oiaf/servicerpt/csia/ and at http://www.eia.doe.gov/oiaf/servicerpt/biv/index.html.

i. Figure 7-9 "Natural Gas Price Projections for AEO2007 Reference Case and EIA Analysis of S.280" presented on page 7-36;

Response to POD 1i
The data presented in Figure 7-9 is a graphical representation of the data from Attachment POD-1.d, which is data from *Table 13 Natural Gas Supply, Disposition, and Prices* for the referenced cases.

j. Figure 7-10 "Distillate Fuel Oil Price Projections for AEO2007 Reference Case and EIA Analysis of S.280" presented on page 7-37;

Response to POD 1j
The data presented in Figure 7-10 is a graphical representation of the data from Attachment POD-1.ef, which is data from *Table 12 Petroleum Product Prices* for the referenced cases.

k. Figure 7-11 "Residual Fuel Oil Price Projections for AEO2007 Reference Case and EIA Analysis of S.280" presented on page 7-38;

Response to POD 1k
The data presented in Figure 7-11 is a graphical representation of the data from Attachment POD-1.ef, which is data from *Table 12 Petroleum Product* Prices for the referenced cases.

l. Figure 7-12 "Coal Price Projections for AEO2007 Reference Case and EIA Analysis of S.280" presented on page 7-39;

Response to POD 1l
The data presented in Figure 7-12 is a graphical representation of the data from Attachment POD-1.g, which is data from *Table 15 Coal Supply, Disposition, and* Prices for the referenced cases.

HEARING EXHIBIT 00000129

m. Figure 7-13 "CO_2 Emission Allowance Price Projections from EIA Analysis of S.280" presented on page 7-40;

Response to POD 1m
The data presented in Figure 7-13 is a graphical representation of the data from Attachment POD-1.h, which is data from *Table 21 Greenhouse Gas Emissions Results* for the referenced cases.

n. Table 7-15 "S.280 Core Case Natural Gas, Fuel Oil, and Coal Price Projections Compared to Non-Adjusted Fuel Price Forecasts" presented on page 7-42;

Response to POD 1n
Attachment POD-1.n.1 and POD-1.n.2 present the source of Table 7-15. The fuel price projections presented in Table 3 of attached POD-1.n.1 include the costs of CO_2 emission allowances, and the fuel price projections presented in Table 119 of attached POD-1.n.2 exclude the costs of CO_2 emission allowances. Table 3 and 119 were provided directly by the EIA to Black & Veatch.

o. Table 7-16 "Forecast of Fuel Prices Delivered to FRCC Considering Potential Impact of S.280 (EIA S.280 Core Case)" presented on page 7-44;

Response to POD 1o
Table 7-16 was developed by comparing the natural gas, distillate fuel oil, residual fuel oil, and coal price projections from Attachment POD-1.o (the AEO2007 Reference Case, which is located at http://www.eia.doe.gov/oiaf/archive/aeo07/excel/aeotab_3.xls) with the corresponding price projections from Table 119 of Attachment POD-1.n.2. The differences were then added to the corresponding price projections for natural gas, distillate fuel oil, residual fuel oil, and coal delivered to the FRCC region from Table 7-1 and Table 7-2 of the Cane Island 4 Need for Power Application to obtain the fuel price projections presented in Table 7-16.

p. Table 7-17 "Projected CO_2 Emission Allowance Prices EIA S.280 Core Case" presented on page 7-45.

Response to POD 1p
Attachment POD-1.h presents the source of Table 7-17, which are the greenhouse gas emission results for the S.280 Core Case. The data in Attachment POD-1.h is presented in $/Metric ton, and to convert to $/Short ton the data in Attachment POD-1.h was multiplied by the conversion factor of 0.907 Short ton per Metric ton.

2. **Please provide all source documents related to the EPA S.2191 Scenario for Projected CO_2 Emission Allowance Prices presented in Table 20-1 on page 20-4 of the Need for Power Application, including but not limited to forecasts, studies, methodology, assumptions, data inputs, and calculations.**

HEARING EXHIBIT 00000152

Response to POD 2
Table 20-1 was formed with data taken from Attachment POD-2.1, the *EPA Analysis of the Lieberman Warner Climate Security Act of 2008*. The IGEM Data from Scenario 2 in the Allowance Price Comparison table on page 27 of Attachment POD-2.1 was used to create Attachment POD-2.2, *Analysis of the EPA's S.2191 CO_2 Emission Allowance Price Projections*. In Attachment POD-2.2 the data from the EPA report was interpolated to provide yearly values using the 5-year average annual escalation rates calculated based on the 5-year interval data included in the EPA's analysis, and was then converted to nominal $/ton using the 2.3 percent general inflation rate used consistently throughout the Cane Island 4 Need for Power Application.

3. **Please provide the CO_2 price forecasts that represent the upper and lower bounds of the range of CO_2 allowance price projections considered by the EPA in its analysis of S.2191 as referenced in Section 20.1.1.9 High Regulated CO_2 Case on Page 20-3 of the Need for Power Application.**

Response to POD 3
The CO_2 emissions allowance price projections from the EPA's analysis of S.2191 that were used to determine the upper and lower bounds of the range of CO_2 emissions allowance price projections considered by EPA in its analysis of S.2191 are presented on Page 27 of Attachment POD-2.1.

Dated this 19th day of June, 2008.

HOPPING GREEN & SAMS, P.A.

Gary V. Perko
Hopping Green & Sams, P.A.
123 S. Calhoun Street
Tallahassee, FL 32314
(850) 222-7500 (telephone)
(850) 224-8551 (facsimile)
Email: GPerko@hgslaw.com

Attorney for Florida Municipal Power Agency

HEARING EXHIBIT

Attachment POD-1.a AEO2007 National Impacts of the Clean Air Amendments of 1990 (CAAA90) Table 117 Reference Case

HEARING EXHIBIT - 00000155

Table 117 National Impacts of the Clean Air Act Amendments of 1990 (CAAAA90)

	2001	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Emissions																												
Nitrogen Oxides (million tons)	4.12	3.75	3.60	3.89	3.82	3.85	2.41	2.41	2.44	2.41	2.43	2.44	2.39	2.39	2.41	2.23	2.21	2.22	2.23	2.23	2.24	2.25	2.25	2.26	2.27	2.27	2.28	2.28
Sulfur Dioxide (million tons)	10.59	10.26	10.21	10.19	9.96	9.89	7.89	6.56	5.78	5.26	5.02	5.04	5.04	5.05	4.85	4.61	4.46	3.98	3.88	3.88	3.75	3.68	3.66	3.66	3.63	3.63	3.61	3.61
From Coal	9.95	9.61	9.76	9.95	9.67	9.61	7.60	6.26	5.48	4.93	4.68	4.69	4.71	4.71	4.82	4.69	4.62	3.99	3.92	3.89	3.84	3.77	3.75	3.74	3.72	3.71	3.71	3.72
Oil/Other	0.64	0.65	0.63	0.25	0.29	0.29	0.29	0.30	0.30	0.33	0.34	0.35	0.33	0.34	0.33	0.32	0.32	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31
Mercury (Tons)	47.50	47.35	51.85	51.89	50.10	49.55	37.21	33.10	31.20	28.35	27.44	27.37	27.44	28.78	28.06	28.24	28.08	28.14	27.76	27.57	26.86	26.19	26.12	25.84	25.48			
Carbon Dioxide (million mtco2e)	3277.66	3189.38	3276.97	3357.10	3384.75	3434.61	3456.93	3585.96	3538.84	3571.12	3604.92	3649.48	3670.88	3718.23	3732.18	3754.16	3785.88	3818.58	3876.58	2925.87	2977.73	3025.77	3068.51	3120.04	3173.15	3226.07	3276.86	3337.98
Allowance Prices																												
Nitrogen Oxides (2005 dollars per ton)																												
Regional/Seasonal	0.00	2590.15	4022.92	2849.19	148.60	114.63	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
East/Annual	0.00	0.00	0.00	0.00	0.00	0.00	2618.26	2515.66	2597.21	2556.95	2692.67	2562.65	2615.89	2585.31	2235.61	2390.91	2385.00	2568.18	2750.16	2876.16	2900.99	1052.68	1117.82	1135.95	1127.37	1052.77	1134.10	1306.56
West/Annual	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sulfur Dioxide (2005 dollars per ton)																												
CAM East	133.58	131.86	488.23	304.82	287.62	170.65	457.82	731.32	800.39	810.51	796.60	795.68	813.41	902.65	972.92	985.27	914.27	961.33	881.31	670.89	956.78	920.24	922.96	867.15	858.93	961.50	935.37	970.35
CAM East	209.31	138.69	1632.89	337.20	449.58	586.61	561.68	638.68	668.61	763.16	810.68	857.12	967.46	984.29	996.25	1018.67	1018.37	1063.84	971.79	1056.70	1095.89	1057.73	1074.07	1078.38	1060.12	950.09	881.57	815.49
CAM West	126.92	133.71	488.08	304.67	286.86	170.50	457.67	365.51	399.99	405.10	398.15	397.58	118.54	115.77	114.73	120.56	114.31	280.64	287.18	334.73	321.94	328.86	302.35	300.47	329.57	327.32	339.47	
CAM West	209.29	139.39	1632.79	337.10	449.49	586.31	561.39	639.25	336.22	381.49	405.14	428.67	533.55	544.63	548.61	558.39	563.52	586.67	548.05	368.77	383.21	377.13	375.86	377.36	363.98	332.47	308.49	285.36
Mercury																												
(million 2005 dollars per ton)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	37.86	37.06	37.06	47.40	47.80	54.04	64.63	75.82	76.43	84.03	88.55	96.84	97.71	97.71	97.71	120.11	122.60	128.32	125.97	132.52	135.95
(thousand 2005 dollars per pound)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	18.93	18.53	18.53	23.70	23.90	27.02	32.32	37.91	38.22	42.02	44.28	48.42	48.85	48.85	48.85	60.06	61.30	64.16	62.98	66.26	67.98
EMM (thousand 2005 dollars per pound)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	19.93	19.50	21.86	24.15	28.12	32.86	38.84	38.81	43.41	48.86	46.28	46.50	46.50	46.51	49.76	57.68	59.30	62.24	63.17	63.49	64.19
Carbon Dioxide (2005 dollars per mtco2e)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Retrofits (gigawatts)																												
Scrubber																												
Planned	0.00	0.00	0.00	1.02	9.72	15.30	16.33	17.21	17.98	19.85	20.06	20.06	20.06	20.06	20.06	20.06	20.06	20.06	20.06	20.06	20.06	20.06	20.06	20.06	20.06	20.06	20.06	20.06
Unplanned	0.00	0.00	0.00	0.00	0.00	10.91	27.65	58.86	66.02	72.03	75.52	84.43	84.73	100.77	104.05	108.08	112.36	114.23	116.08	117.83	118.46	120.47	122.47	122.47	123.21	123.21	123.43	123.43
Total	0.00	0.00	0.00	1.02	9.72	26.29	43.97	68.15	84.00	91.88	95.58	104.49	104.79	120.83	124.11	128.14	132.42	134.30	136.14	137.89	138.53	140.73	142.53	142.53	143.27	143.27	143.49	143.49
Nitrogen Oxides Controls																												
Combustion																												
Planned	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Unplanned	0.00	0.00	0.00	0.00	9.46	14.56	35.05	35.33	35.41	35.59	26.03	26.03	29.17	29.58	29.58	29.58	29.53	29.65	29.65	30.48	30.86	31.44	33.17	33.31	33.36	33.36	33.57	33.57
Total	0.00	0.00	0.00	0.00	9.46	14.56	35.05	35.33	35.41	35.59	26.03	26.03	29.17	29.58	29.58	29.58	29.53	29.65	29.65	30.48	30.86	31.44	33.17	33.31	33.36	33.36	33.57	33.57
SCR Post-combustion																												
Planned	0.00	0.00	0.00	0.45	5.17	5.67	6.45	7.02	7.02	7.02	7.35	7.35	7.35	7.35	7.35	7.35	7.35	7.35	7.35	7.35	7.35	7.35	7.35	7.35	7.35	7.35	7.35	7.35
Unplanned	0.00	0.00	0.00	0.00	13.63	17.73	41.59	65.33	67.01	68.89	69.36	71.18	91.79	95.18	96.13	97.83	98.58	100.83	101.89	103.91	104.88	105.35	106.08	106.58	107.08	109.14	108.34	109.65
Total	0.00	0.00	0.00	0.45	17.80	23.40	48.03	72.35	74.03	75.91	76.69	78.53	99.13	102.52	103.48	105.18	105.93	108.18	109.24	111.26	112.23	112.70	113.43	113.93	114.42	115.49	115.69	116.00
SNCR Post-combustion																												
Planned	0.00	0.00	0.00	0.57	1.45	1.86	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12
Unplanned	0.00	0.00	0.00	0.00	1.36	1.65	0.83	0.91	10.43	10.52	10.61	11.79	14.68	14.68	14.68	14.68	15.23	15.23	15.24	17.24	17.62	18.98	19.83	19.83	19.83	19.92	19.83	20.76
Total	0.00	0.00	0.00	0.57	2.81	3.49	11.95	13.03	12.47	12.64	12.73	15.83	16.80	16.80	16.80	16.80	17.35	17.35	17.46	19.37	19.74	21.08	21.95	21.95	22.05	22.05	22.05	22.89
Coal Production by Sulfur Category (million tons)																												
Low Sulfur (< .61 pounds per million Btu)	528.37	547.27	567.33	567.46	572.67	574.34	583.99	597.68	616.35	621.00	628.95	645.86	647.03	659.24	666.01	664.54	672.43	687.51	713.70	750.34	772.32	797.81	837.00	863.26	881.75	902.52	919.95	940.80
Medium Sulfur	398.10	410.67	429.86	432.93	416.38	402.67	399.85	402.98	401.46	400.62	398.80	399.89	398.03	388.51	388.67	388.23	391.87	401.26	403.35	398.62	417.13	428.70	426.32	439.36	443.73	450.82	458.27	465.10
High Sulfur (> 1.67 pounds per million Btu)	363.32	358.07	367.87	372.31	378.96	381.65	382.69	381.94	380.94	378.36	373.89	367.38	373.09	367.25	367.04	378.76	364.81	368.48	383.23	382.67	364.01	368.96	366.32	372.78	378.40	387.56	393.29	398.35
Interregional Sulfur Dioxide Allowances																												
Target (millions tons)	9.53	9.48	9.48	9.48	9.48	9.48	9.48	5.33	5.33	5.33	5.33	5.33	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25
East	7.72	7.67	7.67	7.67	7.67	7.67	7.67	3.62	3.62	3.62	3.62	3.62	2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.53
West	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71
Cumulative Banked Allowances	7.60	6.82	6.09	5.28	4.96	5.49	7.08	5.42	4.61	4.25	4.12	4.26	3.38	3.73	3.38	1.83	1.69	1.19	0.92	0.69	0.49	0.34	0.25	0.18	0.15	0.12	0.10	0.08
Allowance Revenues (billion 2005 dollars)																												
Nitrogen Oxides	0.00	1.33	1.90	1.35	0.13	0.15	3.64	3.78	3.93	3.85	3.75	3.81	3.65	3.24	2.98	3.25	3.24	3.20	3.45	3.41	3.44	3.83	3.91	3.93	3.91	3.83	3.93	4.15
Sulfur Dioxide	1.35	1.35	4.98	3.11	3.86	3.38	3.41	4.86	4.56	4.25	4.00	3.82	4.07	3.88	4.83	3.95	3.81	3.75	3.11	3.37	3.64	3.45	3.40	3.38	3.32	3.61	3.38	3.52
Mercury	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.38	1.38	1.48	1.60	1.53	1.59	1.77	1.73	1.75	1.69	1.78	1.82	1.79	1.74	1.72	2.03	2.03	2.07	2.03	2.10	2.10
Carbon	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	1.35	2.68	6.89	4.45	3.99	3.45	7.35	9.96	9.85	9.77	9.35	9.17	9.31	8.89	8.74	8.95	8.54	8.45	8.38	8.76	9.01	9.00	9.33	9.34	9.33	9.27	9.41	9.77

Attachment POD-1.bc AEO2007 National Impacts of the Clean Air Act of 1990 (CAAA90) Table 117 Low Price Case & High Price Case

HEARING EXHIBIT – 00000156-A

LOW PRICE CASE
Table 117. National Impacts of the Clean Air Act Amendments of 1990 (CAAA90)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Emissions																												
Nitrogen Oxides (million tons)	4.12	3.75	3.60	3.89	3.82	1.86	2.47	2.42	2.43	2.43	2.45	2.42	2.18	2.18	2.19	2.20	2.20	2.20	2.20	2.22	2.22	2.22	2.23	2.25	2.25	2.26	2.27	2.27
Sulfur Dioxide (million tons)	10.59	10.26	10.21	10.15	9.93	8.91	7.97	6.69	5.50	4.88	4.51	4.41	4.21	4.21	4.11	4.10	4.15	4.04	4.04	3.96	3.97	3.96	3.89	3.87	3.82	3.85	3.80	3.84
From Coal	9.91	9.61	9.74	9.90	9.64	8.64	7.68	6.37	5.08	4.38	4.00	3.89	1.65	1.63	1.53	1.51	1.54	1.45	1.43	1.34	1.35	1.33	1.27	1.25	1.20	1.21	1.14	1.17
Oil/Other	0.69	0.66	0.47	0.25	0.29	0.29	0.29	0.32	0.42	0.50	0.52	0.54	0.55	0.58	0.58	0.59	0.61	0.59	0.61	0.62	0.63	0.63	0.62	0.62	0.63	0.63	0.65	0.67
Mercury (tons)	47.17	47.10	51.75	51.76	52.18	50.53	48.96	37.19	36.03	33.39	29.60	26.65	24.34	22.53	22.05	21.91	21.63	21.28	20.76	19.87	19.13	18.67	18.02	17.03	16.73	16.58	16.30	16.14
Carbon Dioxide (million mtco2e)	2277.44	2309.38	2374.97	2356.17	2384.12	2419.06	2454.89	2490.36	2528.93	2565.44	2595.72	2642.77	2661.06	2692.33	2720.90	2752.62	2779.63	2806.37	2843.30	2874.89	2907.87	2938.04	2968.54	3006.86	3054.07	3107.98	3152.75	3207.46
Allowance Prices																												
Nitrogen Oxides (2005 dollars per ton)																												
Regional/Seasonal	0.00	2618.65	4048.98	2842.60	269.12	312.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
East/Annual	0.00	0.00	0.00	0.00	0.00	0.00	2476.43	2474.15	2478.09	2311.12	2207.68	2141.90	2412.51	2464.27	2320.38	2296.82	2192.40	2461.91	2574.81	2392.99	2514.93	2497.17	2583.94	2699.60	2744.43	2852.55	2848.03	2995.74
West/Annual	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sulfur Dioxide (2005 dollars per ton)																												
CMM East	127.08	111.55	474.54	439.15	308.49	378.86	695.68	762.43	820.68	747.73	718.52	715.88	886.73	901.52	903.97	885.34	850.69	878.24	917.54	964.50	927.58	926.08	904.48	915.99	992.06	993.37	1158.62	1117.79
EMM East	207.89	130.49	1247.71	364.47	457.44	548.84	706.21	801.81	811.10	845.68	902.96	891.80	949.11	942.98	936.51	979.70	982.49	1003.22	1101.17	1118.30	1120.06	1182.69	1154.87	1185.48	1172.82	1192.40	1175.34	1186.60
CMM West	126.92	111.40	474.39	438.99	308.34	378.71	695.53	381.06	410.19	373.71	369.11	357.79	110.20	315.38	316.24	309.71	297.59	307.23	320.99	337.42	324.50	323.97	316.41	320.44	347.07	347.53	405.36	391.07
EMM West	207.78	130.39	1247.61	364.37	457.35	548.75	706.12	400.82	405.46	422.75	451.19	445.81	112.11	329.96	327.70	342.82	343.80	351.05	385.34	391.33	391.95	413.87	404.14	414.85	410.42	417.28	411.31	415.25
Mercury																												
(million 2005 dollars per ton)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	37.06	37.06	49.23	49.23	65.05	76.41	102.79	102.79	102.79	102.79	102.79	104.62	111.23	111.23	111.23	111.23	143.97	143.97	143.97	143.97	143.97
(thousand 2005 dollars per ton	0.00	0.00	0.00	0.00	0.00	0.00	0.00	18.53	18.53	24.61	24.61	32.53	38.20	51.39	51.39	51.39	51.39	51.39	52.31	55.62	55.62	55.62	55.62	71.98	71.98	71.98	71.98	71.98
EMM (thousand 2005 dollars per	0.00	0.00	0.00	0.00	0.00	0.00	0.00	19.05	18.25	21.92	25.28	32.12	16.17	41.08	42.06	46.31	48.52	50.39	50.81	52.45	52.42	53.69	56.53	62.22	64.82	66.74	66.90	64.36
Carbon Dioxide (2005 dollars per	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Retrofits (gigawatts)																												
Scrubber																												
Planned	0.00	0.00	0.00	3.02	9.72	15.38	16.33	17.21	17.98	19.65	20.06	20.06	20.06	20.06	20.06	20.06	20.06	20.06	20.06	20.06	20.06	20.06	20.06	20.06	20.06	20.06	20.06	20.06
Unplanned	0.00	0.00	0.00	0.00	0.00	10.52	23.25	40.44	63.72	79.64	86.40	91.44	96.59	98.76	103.79	104.68	105.59	107.68	109.58	113.95	114.82	115.16	117.10	117.58	118.73	118.84	119.59	119.97
Total	0.00	0.00	0.00	3.02	9.72	25.89	39.57	57.65	81.70	99.30	106.47	111.51	116.59	118.82	123.85	124.74	125.65	127.75	129.64	134.01	134.89	135.22	137.17	137.64	138.79	138.91	139.65	140.04
Nitrogen Oxides Controls																												
Combustion																												
Planned	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Unplanned	0.00	0.00	0.00	0.00	9.03	10.80	24.36	24.58	24.58	25.00	25.00	25.00	28.74	28.74	28.74	28.80	29.19	29.59	30.02	30.02	30.05	30.05	30.33	30.37	30.73	31.16	31.16	31.89
Total	0.00	0.00	0.00	0.00	9.03	10.80	24.36	24.58	24.58	25.00	25.00	25.00	28.74	28.74	28.74	28.80	29.19	29.59	30.02	30.02	30.05	30.05	30.33	30.37	30.73	31.16	31.16	31.89
SCR Post combustion																												
Planned	0.00	0.00	0.00	0.45	5.17	5.87	6.45	7.02	7.02	7.35	7.35	7.35	7.35	7.35	7.35	7.35	7.35	7.35	7.35	7.35	7.35	7.35	7.35	7.35	7.35	7.35	7.35	7.35
Unplanned	0.00	0.00	0.00	0.00	11.98	13.92	50.79	57.75	58.92	58.92	58.92	63.97	84.66	86.75	87.46	88.46	89.87	90.58	91.59	91.97	92.82	93.61	94.73	95.16	96.21	96.94	99.11	100.55
Total	0.00	0.00	0.00	0.45	17.15	19.79	57.24	64.77	65.95	66.27	66.27	71.31	92.00	94.09	94.80	95.81	97.21	97.93	98.93	99.31	100.16	100.96	102.07	102.51	103.55	104.29	106.46	107.90
SNCR Post-combustion																												
Planned	0.00	0.00	0.00	0.57	1.45	1.84	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12
Unplanned	0.00	0.00	0.00	0.00	2.43	3.95	11.42	11.63	11.53	11.70	11.70	15.18	15.21	15.21	15.21	15.51	15.51	16.00	17.13	17.15	17.20	17.20	17.61	17.61	19.92	20.79	21.14	21.68
Total	0.00	0.00	0.00	0.57	3.88	5.79	13.54	13.65	13.65	13.82	13.82	17.30	17.33	17.33	17.33	17.64	17.64	18.13	19.25	19.28	19.32	19.32	19.74	22.05	22.92	23.26	23.26	23.81
Coal Production by Sulfur Category (million tons)																												
Low Sulfur (< .61 pounds per mill	520.37	547.27	547.32	568.62	574.55	578.84	587.85	587.70	594.94	600.07	604.99	619.10	620.70	627.41	634.39	628.76	638.51	648.70	672.28	686.93	692.99	700.23	707.62	721.22	733.74	740.94	767.00	774.97
Medium Sulfur	398.10	418.07	429.55	422.22	408.54	400.34	397.16	396.15	388.57	385.08	386.90	380.95	373.67	372.96	366.82	356.63	354.14	356.27	357.95	359.33	359.43	359.30	356.60	356.20	359.63	367.57	374.84	380.51
High Sulfur (> 1.67 pounds per mi	163.32	158.07	167.97	170.99	175.60	182.81	188.74	200.13	209.57	216.80	217.27	222.86	221.15	225.37	225.29	226.71	227.66	222.09	220.19	218.94	221.48	221.78	220.60	219.28	220.26	227.41	219.05	227.62
Interregional Sulfur Dioxide Allowances																												
Target (millions tons)	9.53	9.48	9.48	9.48	9.48	9.48	9.48	5.33	5.33	5.33	5.33	5.33	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25
East	7.72	7.67	7.67	7.67	7.67	7.67	7.67	3.62	3.62	3.62	3.62	3.62	2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.53
West	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71
Cumulative Banked Allowances	7.60	6.82	6.09	5.42	4.98	5.53	7.04	5.27	4.67	4.68	5.08	5.56	5.06	4.55	4.14	3.73	3.31	2.94	2.58	2.29	1.99	1.72	1.50	1.31	1.15	0.97	0.84	0.67
East	7.60	6.82	6.09	5.42	4.98	5.53	7.04	5.27	4.67	4.68	5.08	5.56	5.06	4.55	4.14	3.73	3.31	2.94	2.58	2.29	1.99	1.72	1.50	1.31	1.15	0.97	0.84	0.67
West	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal Characteristics																												
SO2 Content (pounds per million B	1.93	1.90	1.84	1.85	1.85	1.87	1.88	1.93	1.95	1.98	1.98	1.98	1.97	1.98	1.97	1.96	1.95	1.93	1.90	1.89	1.88	1.87	1.85	1.83	1.83	1.84	1.80	1.82
Mercury Content (pounds per trill	7.61	7.64	7.55	7.57	7.61	7.62	7.64	7.53	7.56	7.60	7.61	7.58	7.54	7.54	7.51	7.42	7.41	7.39	7.37	7.37	7.35	7.33	7.28	7.23	7.19	7.19	7.13	7.15
ACI Controls																												
Spray Cooling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Supplemental Fabric Filter	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.95	2.43	6.84	19.08	27.01	37.12	43.44	49.65	52.74	56.61	60.52	66.85	72.14	79.60	82.52	85.88	89.15	91.35	93.57	96.71	98.80
ACI Mercury Removal (tons)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.74	5.27	7.27	10.90	14.01	15.63	17.20	17.72	18.34	18.87	19.18	20.23	21.29	22.20	22.92	23.42	24.19	24.27	24.43	24.74	25.07
Allowance Revenues (billion 2005 dollars)																												
Nitrogen Oxides	0.00	1.24	1.92	1.34	0.13	0.15	3.73	3.72	3.73	3.48	3.32	3.52	3.05	1.09	2.91	2.88	3.00	3.11	3.23	3.00	3.15	3.13	3.24	3.39	3.44	3.58	3.57	3.76
Sulfur Dioxide	1.35	1.14	4.84	4.46	3.06	3.38	5.55	5.10	4.51	3.65	3.33	3.17	3.71	3.80	3.72	3.63	3.53	3.56	3.71	3.82	3.69	3.66	3.52	3.54	3.79	3.82	4.40	4.29
Mercury	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.38	1.34	1.64	1.46	1.73	1.84	2.32	2.27	2.25	2.22	2.19	2.17	2.21	2.13	2.08	2.00	2.45	2.41	2.39	2.35	2.32
Carbon	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	1.35	2.38	6.76	5.80	3.19	3.53	9.27	10.20	9.58	8.77	8.11	8.43	8.62	9.21	8.89	8.76	8.75	8.85	9.11	9.03	8.97	8.87	8.77	9.38	9.64	9.79	10.32	10.37

HEARING EXHIBIT - 00000157

HIGH PRICE CASE
Table 117. National Impacts of the Clean Air Act Amendments of 1990 (CAAA90)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Emissions																												
Nitrogen Oxides (million tons)	4.12	3.75	3.60	3.89	3.82	3.86	2.41	2.41	2.43	2.44	2.44	2.44	2.20	2.18	2.18	2.19	2.18	2.19	2.17	2.18	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.20
Sulfur Dioxide (million tons)	10.59	10.26	10.21	10.20	9.98	8.95	7.99	6.47	5.91	5.38	4.80	4.49	4.28	4.18	4.04	3.95	3.89	3.85	3.72	3.64	3.63	3.60	3.56	3.54	3.55	3.57	3.54	3.52
From Coal	9.90	9.60	9.74	9.96	9.69	8.66	7.71	6.38	5.84	5.07	4.53	4.42	4.04	3.95	3.81	3.71	3.65	3.62	3.48	3.39	3.38	3.36	3.32	3.30	3.30	3.33	3.30	3.28
Oil/Other	0.69	0.66	0.47	0.25	0.29	0.30	0.29	0.29	0.29	0.31	0.27	0.27	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24
Mercury (tons)	47.26	47.60	51.74	52.02	52.04	50.34	48.87	37.17	37.02	34.33	29.59	26.25	23.56	22.16	22.01	20.62	19.16	18.23	17.54	17.32	16.74	16.28	15.86	15.48	15.42	15.24	14.81	14.57
Carbon Dioxide (million mtco2e)	2277.44	2309.38	2374.97	2356.95	2384.14	2415.91	2451.33	2504.91	2549.09	2585.79	2615.66	2647.10	2681.02	2711.96	2736.86	2769.41	2804.65	2837.13	2854.19	2887.50	2917.97	2956.69	2993.87	3031.68	3076.15	3123.73	3157.23	3213.69
Allowance Prices																												
Nitrogen Oxides (2005 dollars per ton)																												
Regional/Seasonal	0.00	2589.13	4018.68	2854.11	274.47	331.84	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
East/Annual	0.00	0.00	0.00	0.00	0.00	0.00	2544.51	2585.96	2562.14	2497.36	2431.19	2431.98	2586.85	2487.41	2425.62	2431.64	2888.74	3016.03	3019.92	3050.75	3016.33	2946.68	2954.61	2892.34	3030.20	2939.25	3021.89	3134.93
West/Annual	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sulfur Dioxide (2005 dollars per ton)																												
CMM East	127.08	111.55	439.99	296.99	280.64	377.15	402.11	709.10	850.27	660.54	759.21	778.79	905.32	900.67	992.07	881.24	859.55	840.39	957.80	1025.13	875.91	753.56	758.04	735.65	641.96	570.30	560.45	594.20
EMM East	206.72	130.49	1463.24	325.23	392.50	444.20	549.38	700.17	682.52	712.87	777.20	863.65	897.87	957.47	981.64	911.05	877.94	897.01	853.94	884.94	823.99	808.01	713.86	616.53	469.41	350.70	345.18	449.97
CMM West	126.92	111.40	439.83	296.84	280.49	377.00	401.96	354.40	424.98	330.12	379.45	389.24	316.71	335.08	347.07	308.28	300.69	293.98	335.08	358.64	306.42	263.59	265.16	257.32	224.53	199.45	196.00	207.82
EMM West	206.62	130.39	1463.14	325.13	392.41	444.11	549.29	353.49	341.17	356.35	388.51	431.74	314.17	335.03	343.49	319.49	307.20	313.88	298.80	309.66	288.33	282.73	249.78	215.72	164.23	122.68	120.75	157.43
Mercury																												
(million 2005 dollars per ton)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	37.06	37.06	42.17	49.35	65.14	77.29	87.12	87.12	87.12	93.98	105.74	112.66	111.23	132.52	126.68	135.95	143.97	143.97	150.87	150.87	143.97
(thousand 2005 dollars per poun	0.00	0.00	0.00	0.00	0.00	0.00	0.00	18.53	18.53	21.08	24.67	32.58	38.65	43.56	43.56	43.56	46.99	52.87	56.33	55.62	66.26	63.34	67.98	71.98	71.98	75.43	75.43	71.98
EMM (thousand 2005 dollars per	0.00	0.00	0.00	0.00	0.00	0.00	0.00	19.03	19.03	21.99	26.30	34.58	40.21	45.03	43.11	46.77	46.85	55.15	59.24	60.32	65.40	65.96	69.68	71.07	71.03	74.73	73.33	71.13
Carbon Dioxide (2005 dollars per	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Retrofits (gigawatts)																												
Scrubber																												
Planned	0.00	0.00	0.00	3.02	9.72	15.38	16.33	17.21	17.98	19.65	20.06	20.06	20.06	20.06	20.06	20.06	20.06	20.06	20.06	20.06	20.06	20.06	20.06	20.06	20.06	20.06	20.06	20.06
Unplanned	0.00	0.00	0.00	0.00	0.00	10.86	26.14	48.68	65.89	78.40	88.56	92.77	101.41	105.32	109.78	112.86	114.48	114.48	114.48	114.48	114.48	114.48	114.48	114.48	114.48	114.48	114.48	114.48
Total	0.00	0.00	0.00	3.02	9.72	26.24	42.46	65.89	83.87	98.05	108.62	112.83	121.47	125.38	129.85	132.92	134.55	134.55	134.55	134.55	134.55	134.55	134.55	134.55	134.55	134.55	134.55	134.55
Nitrogen Oxides Controls																												
Combustion																												
Planned	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Unplanned	0.00	0.00	0.00	0.00	9.24	11.07	24.61	24.69	25.07	25.13	25.26	26.15	29.27	29.68	29.68	29.74	29.77	30.21	30.21	30.41	30.41	30.41	30.61	32.50	32.63	32.85	32.85	33.18
Total	0.00	0.00	0.00	0.00	9.24	11.07	24.61	24.69	25.07	25.13	25.26	26.15	29.27	29.68	29.68	29.74	29.77	30.21	30.21	30.41	30.41	30.41	30.61	32.50	32.63	32.85	32.85	33.18
SCR Post-combustion																												
Planned	0.00	0.00	0.00	0.45	5.17	5.87	6.45	7.02	7.02	7.35	7.35	7.35	7.35	7.35	7.35	7.35	7.35	7.35	7.35	7.35	7.35	7.35	7.35	7.35	7.35	7.35	7.35	7.35
Unplanned	0.00	0.00	0.00	0.00	12.39	16.69	62.68	66.76	68.49	68.75	71.02	73.66	94.21	98.76	100.59	101.74	103.42	105.40	106.00	107.11	107.56	108.10	108.35	108.35	108.35	108.35	108.35	108.35
Total	0.00	0.00	0.00	0.45	17.55	22.56	69.12	73.78	75.52	76.09	78.37	81.00	101.56	106.11	107.94	109.09	110.77	112.75	113.35	114.46	114.91	115.45	115.70	115.70	115.70	115.70	115.70	115.70
SNCR Post-combustion																												
Planned	0.00	0.00	0.00	0.57	1.45	1.84	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12
Unplanned	0.00	0.00	0.00	0.00	1.36	1.36	8.64	8.69	9.00	9.00	9.00	9.20	14.84	14.96	14.96	15.24	15.64	17.16	17.70	18.56	18.56	19.11	19.50	19.72	19.72	19.72	19.72	19.72
Total	0.00	0.00	0.00	0.57	2.81	3.20	10.76	10.81	11.12	11.12	11.12	11.32	16.97	17.08	17.08	17.37	17.76	19.28	19.83	20.68	20.68	21.23	21.63	21.84	21.84	21.84	21.84	21.84
Coal Production by Sulfur Category (million tons)																												
Low Sulfur (< .61 pounds per mill	520.37	547.27	547.32	565.85	572.77	574.85	585.13	610.61	630.51	634.90	654.29	673.71	680.67	688.92	708.33	724.54	743.78	771.19	806.99	846.27	865.91	888.84	912.95	935.85	978.42	994.38	1035.80	1051.92
Medium Sulfur	398.10	418.07	429.55	424.42	409.91	403.13	400.59	401.47	407.21	414.56	409.12	413.32	413.76	419.61	419.64	422.73	435.19	443.37	455.86	460.52	475.44	482.39	490.68	491.71	499.47	505.86	511.97	522.92
High Sulfur (> 1.67 pounds per mi	163.32	158.07	167.97	172.47	176.12	183.23	192.30	200.96	213.57	222.43	227.18	234.29	232.09	241.89	249.83	255.59	264.57	279.49	288.05	293.71	307.32	317.77	331.95	344.75	359.10	366.29	376.08	386.01
Interregional Sulfur Dioxide Allowances																												
Target (millions tons)	9.53	9.48	9.48	9.48	9.48	9.48	9.48	5.33	5.33	5.33	5.33	5.33	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25
East	7.72	7.67	7.67	7.67	7.67	7.67	7.67	3.62	3.62	3.62	3.62	3.62	2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.53
West	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71
Cumulative Banked Allowances	7.60	6.82	6.09	5.37	4.87	5.40	6.88	5.12	4.08	3.57	3.59	3.79	3.10	2.54	2.10	1.74	1.44	1.16	1.00	0.89	0.81	0.75	0.73	0.73	0.72	0.70	0.70	0.72
East	7.60	6.82	6.09	5.37	4.87	5.40	6.88	5.12	4.08	3.57	3.59	3.79	3.10	2.54	2.10	1.74	1.44	1.16	1.00	0.89	0.81	0.75	0.73	0.73	0.72	0.70	0.70	0.72
West	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal Characteristics																												
SO2 Content (pounds per million B	1.93	1.90	1.84	1.86	1.85	1.88	1.89	1.92	1.94	1.97	1.96	1.97	1.95	1.96	1.95	1.95	1.93	1.90	1.82	1.79	1.78	1.78	1.77	1.77	1.79	1.81	1.81	1.83
Mercury Content (pounds per trill	7.61	7.64	7.56	7.60	7.62	7.63	7.71	7.51	7.54	7.58	7.56	7.57	7.49	7.51	7.49	7.43	7.40	7.38	7.33	7.19	7.17	7.16	7.14	7.12	7.09	7.08	7.08	7.14
ACI Controls																												
Spray Cooling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Supplemental Fabric Filter	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.11	7.65	20.14	34.36	42.03	55.14	64.69	70.36	80.96	92.21	96.91	98.89	101.29	103.29	108.91	112.14	115.02	115.22	115.73	120.72	124.30
ACI Mercury Removal (tons)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.97	6.02	8.51	12.60	16.41	17.85	19.38	19.67	20.99	22.10	22.88	23.15	23.04	23.48	24.24	24.53	25.15	25.13	24.59	24.91	26.42
Allowance Revenues (billion 2005 dollars)																												
Nitrogen Oxides	0.00	1.22	1.90	1.35	0.13	0.16	3.83	2.90	2.86	2.76	2.96	2.96	3.24	3.12	3.04	3.30	3.62	3.78	3.79	3.83	3.78	3.70	3.71	3.63	3.80	3.69	3.79	3.93
Sulfur Dioxide	1.35	1.14	4.49	3.01	2.80	3.38	3.21	4.73	5.04	3.56	3.65	3.65	3.88	3.77	4.01	3.48	3.34	3.24	3.56	3.73	3.18	2.71	2.70	2.61	2.28	2.03	1.98	2.09
Mercury	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.38	1.37	1.45	1.46	1.71	1.82	1.95	1.92	1.80	1.80	1.93	1.98	1.93	2.22	2.06	2.16	2.23	2.22	2.30	2.23	2.10
Carbon	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	1.35	2.37	6.39	4.36	2.93	3.53	7.04	10.00	10.27	8.76	9.07	9.33	8.94	8.83	8.97	8.58	8.76	8.95	9.32	9.48	9.18	8.47	8.56	8.46	8.30	8.02	8.01	8.12

HEARING EXHIBIT - 00000152

Attachment POD-1.d. Table 13 Natural Gas Supply, Disposition, and Prices

Cases:

Reference
Core S.280
No International S.280
Fixed 30% Offset S.280
No Nuclear S.280
Low Discount S.280
Unlimited Offset S.280
High Auction S.280
Commercial Covered S.280
High Technology S.280
Ref NB S.280
Ref NB+noCCS S.280
Ref NBLNG+noCCS S.280

HEARING EXHIBIT - 0000015

Table 13 Natural Gas Supply, Disposition, and Prices
(trillion cubic feet, unless otherwise noted)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2005-2030
Production																												
Dry Gas Production 1/	18.76	18.23	18.57	19.12	19.41	19.41	19.35	19.22	19.45	19.30	19.66	19.80	19.61	19.74	20.16	20.67	20.79	20.90	20.98	20.91	20.86	20.59	20.47	20.46	20.53	20.57	20.53	0.5%
Supplemental Natural Gas 2/	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.1%
Net Imports	3.40	3.57	3.29	3.43	3.87	4.24	4.55	4.84	5.00	5.38	5.31	5.62	5.80	5.73	5.44	5.13	5.35	5.21	5.10	5.13	5.17	5.58	5.54	5.57	5.61	5.52	5.45	1.7%
Pipeline 3/	2.81	3.01	2.74	2.67	2.76	2.82	2.74	2.58	2.62	2.85	2.72	2.63	2.57	2.36	2.14	1.88	1.65	1.59	1.44	1.32	1.33	1.20	1.17	1.15	1.09	0.98	0.92	-4.6%
Liquefied Natural Gas	0.59	0.57	0.55	0.76	1.11	1.42	1.81	2.26	2.38	2.53	2.59	2.99	3.23	3.37	3.30	3.25	3.69	3.62	3.65	3.80	3.85	4.38	4.37	4.41	4.53	4.54	4.53	8.7%
Total Supply	22.22	21.87	21.93	22.62	23.35	23.72	23.97	24.13	24.52	24.75	25.04	25.29	25.48	25.54	25.67	25.88	26.21	26.18	26.15	26.11	26.11	26.24	26.08	26.10	26.21	26.16	26.06	0.7%
Consumption by Sector																												
Residential	4.87	4.84	4.48	4.88	4.96	4.99	5.03	5.08	5.13	5.15	5.17	5.19	5.22	5.21	5.22	5.24	5.27	5.27	5.28	5.28	5.30	5.29	5.30	5.31	5.32	5.31	5.31	0.4%
Commercial	3.13	3.05	2.92	3.02	3.10	3.16	3.22	3.29	3.36	3.43	3.48	3.53	3.58	3.61	3.65	3.70	3.75	3.80	3.85	3.89	3.93	3.98	4.03	4.09	4.14	4.18	4.24	1.3%
Industrial 4/	7.22	6.64	6.76	7.15	7.21	7.35	7.63	7.53	7.61	7.62	7.78	7.67	7.71	7.83	7.79	7.83	8.02	8.02	8.03	8.12	8.19	8.42	8.34	8.42	8.63	8.72	8.65	1.1%
Natural Gas-to-Liquids Heat and Power 5/	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Natural Gas to Liquids Production 6/	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Electric Power 7/	5.48	5.78	5.88	5.90	6.38	6.50	6.38	6.51	6.69	6.83	6.87	7.11	7.18	7.10	7.13	7.15	7.19	7.10	7.00	6.84	6.72	6.59	6.46	6.34	6.18	6.00	5.92	0.1%
Transportation 8/	0.03	0.03	0.04	0.05	0.05	0.05	0.06	0.06	0.07	0.07	0.07	0.08	0.08	0.08	0.09	0.09	0.09	0.10	0.10	0.10	0.10	0.11	0.11	0.11	0.12	0.12	0.12	5.7%
Pipeline Fuel	0.57	0.56	0.55	0.62	0.63	0.64	0.64	0.65	0.66	0.66	0.67	0.68	0.68	0.68	0.72	0.75	0.76	0.77	0.78	0.78	0.78	0.77	0.77	0.77	0.77	0.77	0.77	1.3%
Lease and Plant Fuel 9/	1.10	1.07	1.09	1.07	1.08	1.07	1.07	1.06	1.06	1.05	1.07	1.07	1.07	1.08	1.12	1.16	1.17	1.18	1.17	1.17	1.16	1.14	1.13	1.12	1.12	1.12	1.12	0.2%
Total	22.39	21.98	21.72	22.68	23.40	23.77	24.02	24.18	24.57	24.80	25.09	25.32	25.53	25.60	25.73	25.93	26.26	26.24	26.20	26.17	26.17	26.30	26.14	26.16	26.27	26.23	26.12	0.7%
Discrepancy 10/	-0.17	-0.11	0.21	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.03	-0.05	-0.05	-0.05	-0.05	-0.05	-0.06	-0.06	-0.06	-0.06	-0.06	-0.06	-0.06	-0.06	-0.06	-0.06	N/A
Natural Gas Prices																												
(2005 dollars per million Btu)																												
Henry Hub Spot Price	6.08	8.60	7.07	7.23	7.17	6.60	6.26	5.83	5.66	5.49	5.52	5.46	5.56	5.78	5.68	5.62	5.71	5.71	5.85	5.98	6.15	6.14	6.17	6.25	6.39	6.48	6.52	-1.1%
Average Lower 48 Wellhead Price 11/	5.63	7.29	6.47	6.45	6.40	5.88	5.59	5.17	5.02	4.87	4.90	4.84	4.94	5.13	5.05	4.99	5.07	5.07	5.20	5.32	5.47	5.46	5.48	5.56	5.69	5.77	5.80	-0.9%
(2005 dollars per thousand cubic feet)																												
Average Lower 48 Wellhead Price 11/	5.80	7.51	6.67	6.65	6.59	6.05	5.76	5.33	5.17	5.01	5.04	4.99	5.09	5.28	5.20	5.14	5.22	5.22	5.35	5.48	5.63	5.62	5.65	5.73	5.86	5.94	5.98	-0.9%
Delivered Prices																												
Residential	11.05	12.80	13.43	12.19	12.09	11.59	11.31	10.91	10.75	10.56	10.60	10.55	10.64	10.87	10.80	10.75	10.86	10.85	10.99	11.16	11.28	11.30	11.35	11.45	11.60	11.71	11.77	-0.3%
Commercial	9.69	11.54	11.72	10.58	10.46	9.92	9.62	9.19	9.01	8.79	8.81	8.73	8.80	9.00	8.92	8.85	8.93	8.89	9.01	9.13	9.24	9.23	9.25	9.32	9.45	9.52	9.58	-0.7%
Industrial 4/	6.67	8.41	7.67	7.58	7.51	6.94	6.62	6.20	6.04	5.85	5.86	5.82	5.91	6.10	6.05	6.01	6.08	6.06	6.18	6.31	6.43	6.40	6.44	6.52	6.63	6.71	6.76	-0.9%
Electric Power 7/	6.27	8.42	7.17	7.32	7.27	6.72	6.40	6.00	5.86	5.66	5.70	5.66	5.76	5.96	5.89	5.84	5.93	5.89	6.01	6.12	6.23	6.22	6.24	6.33	6.43	6.50	6.51	-1.0%
Transportation 12/	12.28	15.20	12.34	12.65	12.50	12.69	14.38	13.91	13.69	13.44	13.33	13.25	13.28	13.42	13.34	13.33	13.36	13.34	13.47	13.50	13.59	13.62	13.57	13.64	13.76	13.80	13.86	-0.4%
Average 13/	8.06	9.94	9.41	9.02	8.92	8.37	8.07	7.67	7.51	7.31	7.33	7.28	7.37	7.57	7.51	7.46	7.54	7.53	7.66	7.80	7.92	7.91	7.96	8.06	8.18	8.27	8.33	-0.7%

1/ Marketed production (wet) minus extraction losses.
2/ Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
3/ Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida.
4/ Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
5/ Includes any natural gas used in the process of converting natural gas to liquid fuel that is not actually converted..
6/ Includes any natural gas that is converted into liquid fuel.
7/ Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
8/ Compressed natural gas used as vehicle fuel.
9/ Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
10/ Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2004 and 2005 values include net storage injections.
11/ Represents lower 48 onshore and offshore supplies.
12/ Compressed natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
13/ Weighted average prices. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
Sources: 2004 supply values; and lease, plant, and pipeline fuel consumption: Energy Information Administration (EIA), Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005). 2005 supply values; and lease, plant, and pipeline fuel consumption; and wellhead price: EIA, Natural Gas Monthly, DOE/EIA-0130(2006/04) (Washington, DC, April 2006). Other 2004 and 2005 consumption based on: EIA, Annual Energy Review 2005, DOE/EIA-0384(2005) (Washington, DC, July 2006). 2004 wellhead price: Minerals Management Service and EIA, Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005). 2004 residential and commercial delivered prices: EIA, Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005). 2005 residential and commercial delivered prices: EIA, Natural Gas Monthly, DOE/EIA-0130 (2006/04) (Washington, DC, April 2006). 2004 and 2005 electric power prices: EIA, Electric Power Monthly, DOE/EIA-0226, May 2005 through April 2006, Table 4.11.A. 2004 and 2005 industrial delivered prices are estimated based on: EIA, Manufacturing Energy Consumption Survey 1994 and industrial and wellhead prices from the Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005) and the Natural Gas Monthly, DOE/EIA-0130(2006/04) (Washington, DC, April 2006). 2004 transportation sector delivered prices are based on: EIA, Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005) and estimated state taxes, federal taxes, and dispensing costs or charges. 2005 transportation sector delivered prices are model results. Projections: EIA, AEO2007 National Energy Modeling System run aeo2007.d112106a.

HEARING EXHIBIT - 00000160

Table 13. Natural Gas Supply, Disposition, and Prices
(trillion cubic feet, unless otherwise noted)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Production																											
Dry Gas Production 1/	18.76	18.23	18.58	19.04	19.41	19.48	19.50	19.53	19.48	19.26	19.61	19.50	19.49	19.51	19.94	20.45	20.43	20.62	20.66	20.53	20.34	20.22	20.08	19.93	19.85	19.83	19.85
Supplemental Natural Gas 2/	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Net Imports	3.40	3.57	3.29	3.41	3.87	4.28	4.67	5.09	5.10	5.38	5.28	5.45	5.52	5.36	5.07	4.77	4.95	4.82	4.73	4.67	4.58	4.48	4.34	4.16	4.08	4.13	4.28
Pipeline 3/	2.81	3.01	2.74	2.65	2.75	2.85	2.80	2.70	2.70	2.89	2.76	2.64	2.55	2.31	2.07	1.81	1.55	1.46	1.31	1.18	1.14	1.01	0.87	0.75	0.68	0.70	0.78
Liquefied Natural Gas	0.59	0.57	0.55	0.76	1.11	1.43	1.87	2.39	2.40	2.50	2.52	2.81	2.97	3.05	2.99	2.96	3.41	3.37	3.42	3.49	3.43	3.47	3.47	3.42	3.40	3.43	3.50
Total Supply	22.22	21.87	21.93	22.52	23.35	23.83	24.24	24.69	24.66	24.72	24.96	25.02	25.08	24.94	25.07	25.29	25.46	25.51	25.46	25.27	24.99	24.77	24.49	24.17	24.00	24.04	24.21
Consumption by Sector																											
Residential	4.87	4.84	4.48	4.89	4.97	5.00	5.03	5.06	5.11	5.13	5.14	5.16	5.18	5.17	5.18	5.20	5.22	5.21	5.21	5.21	5.22	5.21	5.20	5.20	5.22	5.21	5.21
Commercial	3.13	3.05	2.92	3.02	3.11	3.16	3.21	3.28	3.34	3.42	3.47	3.53	3.57	3.61	3.65	3.70	3.75	3.80	3.85	3.89	3.94	4.00	4.05	4.12	4.18	4.26	4.33
Industrial 4/	7.22	6.64	6.76	7.08	7.25	7.44	7.63	7.65	7.77	7.67	7.83	7.77	7.81	7.83	7.82	7.88	8.00	8.02	8.22	8.32	8.20	8.24	8.27	8.40	8.58	8.47	8.69
Natural Gas-to-Liquids Heat and Power 5/	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas to Liquids Production 6/	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electric Power 7/	5.51	5.83	5.89	5.87	6.33	6.51	6.64	6.96	6.69	6.77	8.75	6.79	6.74	8.55	8.55	6.57	6.53	6.50	6.20	5.89	5.68	5.40	5.05	4.56	4.14	4.21	4.09
Transportation 8/	0.03	0.03	0.04	0.05	0.05	0.05	0.06	0.06	0.07	0.07	0.07	0.08	0.08	0.08	0.09	0.09	0.09	0.10	0.10	0.10	0.10	0.11	0.11	0.11	0.12	0.12	0.12
Pipeline Fuel	0.57	0.56	0.55	0.61	0.63	0.64	0.65	0.66	0.67	0.67	0.68	0.68	0.69	0.69	0.72	0.76	0.77	0.78	0.77	0.77	0.76	0.76	0.75	0.74	0.73	0.73	0.73
Lease and Plant Fuel 9/	1.10	1.07	1.09	1.06	1.08	1.08	1.07	1.07	1.06	1.05	1.07	1.07	1.07	1.07	1.11	1.15	1.16	1.16	1.16	1.15	1.13	1.12	1.11	1.10	1.09	1.09	1.09
Total	22.43	22.02	21.73	22.57	23.40	23.88	24.29	24.74	24.71	24.77	25.01	25.08	25.14	25.00	25.13	25.35	25.51	25.57	25.51	25.33	25.04	24.83	24.55	24.23	24.06	24.10	24.26
Discrepancy 10/	-0.20	-0.15	0.21	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.06	-0.06	-0.05	-0.06	-0.06	-0.06	-0.06	-0.06	-0.06
Natural Gas Prices																											
(2005 dollars per million Btu)																											
Henry Hub Spot Price	6.08	8.60	7.07	7.16	7.16	6.67	6.41	6.07	5.72	5.44	5.45	5.35	5.44	5.58	5.49	5.47	5.46	5.51	5.67	5.79	5.83	5.93	5.99	6.03	6.00	6.00	6.12
Average Lower 48 Wellhead Price 11/	5.63	7.29	6.47	6.39	6.39	5.94	5.71	5.40	5.08	4.83	4.83	4.74	4.83	4.96	4.87	4.85	4.84	4.89	5.03	5.14	5.18	5.27	5.32	5.36	5.33	5.34	5.44
(2005 dollars per thousand cubic feet)																											
Average Lower 48 Wellhead Price 11/	5.80	7.51	6.67	6.58	6.58	6.12	5.88	5.56	5.23	4.97	4.98	4.88	4.97	5.10	5.02	5.00	4.99	5.04	5.19	5.29	5.34	5.42	5.48	5.52	5.49	5.50	5.61
Delivered Prices																											
Residential	11.05	12.80	13.43	12.12	12.08	11.65	11.42	11.13	10.81	10.52	10.55	10.48	10.54	10.70	10.61	10.61	10.62	10.65	10.82	10.95	10.96	11.08	11.16	11.22	11.19	11.21	11.33
Commercial	9.69	11.54	11.72	10.51	10.45	9.98	9.74	9.41	9.07	8.75	8.76	8.65	8.71	8.84	8.74	8.72	8.70	8.70	8.84	8.93	8.93	9.01	9.06	9.08	9.04	9.03	9.12
Industrial 4/	6.67	8.41	7.67	7.53	7.50	7.02	6.75	6.42	6.79	6.56	6.59	6.54	6.69	6.89	6.89	6.98	7.05	7.16	7.39	7.59	7.74	7.95	8.14	8.32	8.43	8.63	8.91
Electric Power 7/	6.26	8.41	7.17	7.25	7.25	6.78	6.56	6.27	6.58	6.31	6.34	6.28	6.41	6.60	6.59	6.66	6.73	6.83	7.05	7.21	7.31	7.50	7.67	7.77	7.89	8.08	8.38
Transportation 12/	12.30	14.16	11.29	11.41	11.27	11.51	13.51	13.15	13.49	13.20	13.16	13.09	13.19	13.33	13.31	13.41	13.41	13.49	13.76	13.89	14.03	14.25	14.38	14.57	14.74	14.88	15.20
Average 13/	8.08	9.93	9.41	8.97	8.91	8.43	8.18	7.85	7.98	7.72	7.74	7.68	7.80	7.98	7.95	7.99	8.04	8.11	8.32	8.49	8.59	8.77	8.93	9.06	9.13	9.24	9.46

1/ Marketed production (wet) minus extraction losses.
2/ Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
3/ Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida.
4/ Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
5/ Includes any natural gas used in the process of converting natural gas to liquid fuel that is not actually converted.
6/ Includes any natural gas that is converted into liquid fuel.
7/ Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
8/ Compressed natural gas used as vehicle fuel.
9/ Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
10/ Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2004 and 2005 values include net storage injections.
11/ Represents lower 48 onshore and offshore supplies.
12/ Compressed natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
13/ Weighted average prices. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
Sources: 2004 supply values; and lease, plant, and pipeline fuel consumption: Energy Information Administration (EIA), Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005). 2005 supply values; and lease, plant, and pipeline fuel consumption; and wellhead price: EIA, Natural Gas Monthly, DOE/EIA-0130(2006/04) (Washington, DC, April 2006). Other 2004 and 2005 consumption based on: EIA, Annual Energy Review 2005, DOE/EIA-0384(2005) (Washington, DC, July 2006). 2004 wellhead price: Minerals Management Service and EIA, Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005). 2004 residential and commercial delivered prices: EIA, Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005). 2005 residential and commercial delivered prices: EIA, Natural Gas Monthly, DOE/EIA-0130 (2006/04) (Washington, DC, April 2006). 2004 and 2005 electric power prices: EIA, Electric Power Monthly, DOE/EIA-0226, May 2005 through April 2006, Table 4.11.A. 2004 and 2005 industrial delivered prices are estimated based on: EIA, Manufacturing Energy Consumption Survey 1994 and industrial and wellhead prices from the Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005) and the Natural Gas Monthly, DOE/EIA-0130(2006/04) (Washington, DC, April 2006). 2004 transportation sector delivered prices are based on: EIA, Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005) and estimated state taxes, federal taxes, and dispensing costs or charges. 2005 transportation sector delivered prices are model results. Projections: EIA, AEO2007 National Energy Modeling System run s280.d060107a

HEARING EXHIBIT 00000121

Table 13. Natural Gas Supply, Disposition, and Prices
(trillion cubic feet, unless otherwise noted)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Production																											
Dry Gas Production 1/	18.76	18.21	18.58	19.06	19.51	19.51	19.55	19.49	19.51	19.28	19.45	19.58	19.38	19.35	19.78	20.23	20.43	20.64	20.55	20.31	20.08	20.00	19.93	19.98	19.96	19.72	19.73
Supplemental Natural Gas 2/	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Net Imports	3.40	3.57	3.28	3.39	3.87	4.30	4.70	5.18	5.13	5.39	5.19	5.44	5.32	5.09	4.75	4.38	4.45	4.39	4.22	4.23	4.03	4.08	4.18	4.31	4.26	4.16	4.24
Pipeline 3/	2.81	3.01	2.74	2.63	2.76	2.85	2.82	2.75	2.71	2.90	2.72	2.63	2.51	2.26	2.01	1.71	1.47	1.40	1.25	1.09	1.03	0.89	0.81	0.78	0.74	0.73	0.78
Liquefied Natural Gas	0.59	0.57	0.55	0.76	1.11	1.44	1.88	2.43	2.40	2.49	2.47	2.81	2.80	2.83	2.74	2.67	2.99	2.99	2.97	3.14	3.00	3.20	3.37	3.53	3.52	3.43	3.46
Total Supply	22.22	21.87	21.93	22.53	23.46	23.88	24.32	24.94	24.72	24.73	24.71	25.10	24.77	24.51	24.60	24.72	24.95	25.10	24.84	24.61	24.19	24.15	24.19	24.36	24.29	23.95	24.04
Consumption by Sector																											
Residential	4.87	4.84	4.48	4.89	4.96	5.00	5.03	5.06	5.10	5.12	5.15	5.16	5.19	5.18	5.19	5.21	5.24	5.23	5.23	5.23	5.24	5.22	5.22	5.21	5.21	5.20	5.21
Commercial	3.13	3.05	2.92	3.02	3.10	3.16	3.21	3.27	3.34	3.41	3.48	3.53	3.58	3.62	3.67	3.72	3.78	3.82	3.87	3.91	3.97	4.03	4.09	4.14	4.20	4.28	4.37
Industrial 4/	7.22	6.64	6.76	7.09	7.34	7.40	7.52	7.61	7.76	7.65	7.67	7.87	7.69	7.72	7.78	7.82	7.93	8.12	8.12	8.07	8.14	8.20	8.35	8.31	8.34	8.46	8.47
Natural Gas-to-Liquids Heat and Pow	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas to Liquids Production 6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electric Power 7/	5.51	5.83	5.90	5.86	6.34	6.58	6.83	7.24	6.78	6.80	6.65	6.76	6.55	6.22	6.11	6.05	6.06	5.96	5.66	5.47	4.92	4.79	4.64	4.81	4.64	4.13	4.11
Transportation 8/	0.03	0.03	0.04	0.05	0.05	0.05	0.06	0.06	0.07	0.07	0.07	0.08	0.08	0.08	0.09	0.09	0.09	0.10	0.10	0.10	0.10	0.11	0.11	0.11	0.12	0.12	0.12
Pipeline Fuel	0.57	0.56	0.55	0.62	0.63	0.64	0.65	0.67	0.67	0.67	0.67	0.68	0.68	0.68	0.71	0.75	0.76	0.76	0.76	0.75	0.74	0.74	0.74	0.74	0.74	0.73	0.73
Lease and Plant Fuel 9/	1.10	1.07	1.09	1.06	1.08	1.08	1.08	1.08	1.06	1.05	1.06	1.07	1.06	1.06	1.10	1.15	1.15	1.16	1.16	1.14	1.12	1.11	1.11	1.10	1.10	1.08	1.08
Total	22.43	22.02	21.73	22.58	23.51	23.92	24.37	24.99	24.77	24.79	24.76	25.15	24.83	24.56	24.65	24.78	25.01	25.15	24.89	24.67	24.25	24.21	24.25	24.42	24.35	24.01	24.10
Discrepancy 10/	-0.20	-0.15	0.20	0.05	-0.05	-0.04	-0.05	-0.05	0.05	-0.05	0.05	0.05	-0.05	0.05	0.05	-0.05	-0.05	0.06	-0.05	-0.06	-0.06	-0.06	-0.06	-0.06	-0.06	-0.06	-0.06
Natural Gas Prices																											
(2005 dollars per million Btu)																											
Henry Hub Spot Price	6.08	8.60	7.07	7.18	7.24	6.70	6.44	6.17	5.74	5.43	5.32	5.35	5.37	5.44	5.36	5.31	5.45	5.55	5.62	5.63	5.65	5.77	5.92	6.14	6.19	6.02	6.07
Average Lower 48 Wellhead Price 1	5.63	7.29	6.47	6.41	6.46	5.97	5.74	5.49	5.10	4.81	4.72	4.75	4.76	4.83	4.75	4.71	4.83	4.93	4.98	5.00	5.01	5.12	5.26	5.46	5.51	5.35	5.40
(2005 dollars per thousand cubic feet)																											
Average Lower 48 Wellhead Price 1	5.80	7.51	6.67	6.60	6.66	6.15	5.91	5.65	5.25	4.96	4.86	4.89	4.91	4.97	4.89	4.85	4.98	5.08	5.13	5.15	5.16	5.28	5.42	5.63	5.67	5.51	5.56
Delivered Prices																											
Residential	11.05	12.80	13.43	12.13	12.16	11.68	11.45	11.22	10.83	10.51	10.43	10.47	10.47	10.58	10.49	10.45	10.58	10.66	10.74	10.78	10.76	10.91	11.07	11.31	11.38	11.24	11.28
Commercial	9.69	11.54	11.72	10.51	10.53	10.01	9.77	9.51	9.09	8.75	8.65	8.66	8.64	8.71	8.62	8.56	8.68	8.73	8.77	8.78	8.74	8.85	8.98	9.18	9.22	9.04	9.07
Industrial 4/	6.67	8.41	7.67	7.53	7.56	7.04	6.80	6.54	7.07	6.77	6.75	6.84	6.94	7.12	7.16	7.23	7.49	7.66	7.85	8.03	7.88	8.15	8.44	8.86	9.10	9.14	9.41
Electric Power 7/	6.26	8.41	7.17	7.25	7.33	6.82	6.61	6.40	6.87	6.52	6.46	6.59	6.65	6.80	6.80	6.87	7.07	7.26	7.41	7.59	7.37	7.65	7.93	8.36	8.57	8.55	8.85
Transportation 12/	12.30	14.16	11.25	11.42	11.33	11.53	11.53	11.23	11.77	11.40	11.31	11.40	11.47	11.57	11.59	11.67	11.83	14.00	14.22	14.31	14.16	14.46	14.68	15.06	15.34	15.36	15.66
Average 13/	8.06	9.93	9.41	8.97	8.97	8.46	8.22	7.95	8.16	7.84	7.80	7.87	7.94	8.10	8.08	8.11	8.30	8.44	8.59	8.71	8.63	8.85	9.08	9.41	9.58	9.54	9.71

1/ Marketed production (wet) minus extraction losses.
2/ Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
3/ Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida.
4/ Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
5/ Includes any natural gas used in the process of converting natural gas to liquid fuel that is not actually converted..
6/ Includes any natural gas that is converted into liquid fuel.
7/ Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
8/ Compressed natural gas used as vehicle fuel.
9/ Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
10/ Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2004 and 2005 values include net storage injections.
11/ Represents lower 48 onshore and offshore supplies.
12/ Compressed natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
13/ Weighted average prices. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
Sources: 2004 supply values; and lease, plant, and pipeline fuel consumption: Energy Information Administration (EIA), Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005). 2005 supply values; and lease, plant, and pipeline fuel consumption; and wellhead price: EIA, Natural Gas Monthly, DOE/EIA-0130(2006/04) (Washington, DC, April 2006). Other 2004 and 2005 consumption based on: EIA, Annual Energy Review 2005, DOE/EIA-0384(2005) (Washington, DC, July 2006). 2004 wellhead price: Minerals Management Service and EIA, Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005). 2004 residential and commercial delivered prices: EIA, Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005). 2005 residential and commercial delivered prices: EIA, Natural Gas Monthly, DOE/EIA-0130 (2006/04) (Washington, DC, April 2006). 2004 and 2005 electric power prices: EIA, Electric Power Monthly, DOE/EIA-0226, May 2005 through April 2006, Table 4.11.A. 2004 and 2005 industrial delivered prices are estimated based on: EIA, Manufacturing Energy Consumption Survey 1994 and industrial and wellhead prices from the Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005) and the Natural Gas Monthly, DOE/EIA-0130(2006/04) (Washington, DC, April 2006). 2004 transportation sector delivered prices are based on: EIA, Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005) and estimated state taxes, federal taxes, and dispensing costs or charges. 2005 transportation sector delivered prices are model results. Projections: EIA, AEO2007 National Energy Modeling System run s280nointl.d061507a.

HEARING EXHIBIT - 00000162

Table 13 Natural Gas Supply, Disposition, and Prices
(trillion cubic feet, unless otherwise noted)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Production																											
Dry Gas Production 1/	18.76	18.23	18.58	19.05	19.44	19.48	19.37	19.36	19.42	19.18	19.51	19.52	19.45	19.54	19.94	20.45	20.56	20.80	20.88	20.71	20.76	20.55	20.46	20.44	20.45	20.45	20.29
Supplemental Natural Gas 2/	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Net Imports	3.40	3.57	3.29	3.41	3.87	4.28	4.57	4.92	5.02	5.30	5.16	5.46	5.60	5.56	5.22	4.91	5.03	4.98	4.95	5.03	5.14	5.21	5.21	5.27	5.14	4.90	4.92
Pipeline 3/	2.81	3.01	2.74	2.65	2.75	2.84	2.76	2.62	2.64	2.82	2.67	2.58	2.51	2.32	2.09	1.84	1.59	1.54	1.42	1.31	1.32	1.22	1.21	1.22	1.14	0.99	0.88
Liquefied Natural Gas	0.59	0.57	0.55	0.76	1.11	1.43	1.82	2.30	2.38	2.47	2.49	2.88	3.09	3.25	3.13	3.07	3.43	3.45	3.53	3.72	3.81	3.99	4.00	4.05	4.00	3.90	4.04
Total Supply	22.22	21.87	21.93	22.53	23.38	23.83	24.01	24.34	24.52	24.55	24.73	25.06	25.13	25.18	25.23	25.43	25.66	25.85	25.90	25.81	25.97	25.83	25.74	25.78	25.65	25.41	25.29
Consumption by Sector																											
Residential	4.87	4.84	4.48	4.88	4.97	5.00	5.04	5.07	5.12	5.13	5.15	5.16	5.18	5.17	5.18	5.19	5.21	5.20	5.20	5.19	5.20	5.18	5.18	5.17	5.18	5.17	5.18
Commercial	3.13	3.05	2.92	3.02	3.10	3.16	3.21	3.29	3.35	3.42	3.48	3.53	3.57	3.60	3.65	3.70	3.74	3.79	3.82	3.86	3.90	3.95	4.00	4.06	4.12	4.18	4.26
Industrial 4/	7.22	6.64	6.76	7.08	7.32	7.53	7.58	7.58	7.83	7.71	7.84	7.89	7.80	7.99	7.86	7.87	7.92	8.04	8.09	8.09	8.26	8.25	8.35	8.61	8.68	8.66	8.64
Natural Gas-to-Liquids Heat and Pow	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas to Liquids Production 6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electric Power 7/	5.51	5.83	5.89	5.87	6.29	6.42	6.47	6.68	6.47	6.56	6.50	6.70	6.79	6.63	6.68	6.72	6.81	6.84	6.80	6.69	6.62	6.49	6.25	5.99	5.72	5.46	5.28
Transportation 8/	0.03	0.03	0.04	0.05	0.05	0.05	0.06	0.06	0.07	0.07	0.07	0.08	0.08	0.08	0.09	0.09	0.09	0.10	0.10	0.10	0.10	0.11	0.11	0.11	0.12	0.12	0.12
Pipeline Fuel	0.57	0.56	0.55	0.62	0.63	0.64	0.64	0.65	0.66	0.66	0.67	0.68	0.68	0.69	0.72	0.75	0.77	0.78	0.78	0.78	0.78	0.78	0.77	0.77	0.77	0.76	0.76
Lease and Plant Fuel 9/	1.10	1.07	1.09	1.06	1.08	1.08	1.07	1.06	1.06	1.05	1.06	1.07	1.07	1.07	1.11	1.15	1.16	1.17	1.17	1.16	1.15	1.14	1.13	1.12	1.12	1.12	1.11
Total	22.43	22.02	21.72	22.58	23.43	23.88	24.06	24.40	24.57	24.60	24.78	25.11	25.18	25.23	25.28	25.48	25.71	25.91	25.96	25.87	26.02	25.89	25.79	25.84	25.71	25.47	25.35
Discrepancy 10/	-0.20	-0.15	0.21	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	0.05	0.05	-0.05	-0.05	-0.05	-0.05	0.05	0.05	-0.06	-0.06	-0.05	-0.06	-0.06	-0.06	-0.06	-0.06	-0.06
Natural Gas Prices																											
(2005 dollars per million Btu)																											
Henry Hub Spot Price	6.08	8.60	7.07	7.17	7.18	6.67	6.31	5.92	5.65	5.39	5.39	5.39	5.47	5.64	5.53	5.49	5.57	5.68	5.87	5.96	6.16	6.22	6.28	6.41	6.42	6.40	6.35
Average Lower 48 Wellhead Price 1	5.63	7.29	6.47	6.40	6.41	5.95	5.61	5.26	5.02	4.78	4.78	4.78	4.86	5.01	4.91	4.87	4.94	5.04	5.21	5.30	5.48	5.53	5.59	5.70	5.72	5.70	5.65
(2005 dollars per thousand cubic feet)																											
Average Lower 48 Wellhead Price 1	5.80	7.51	6.67	6.59	6.61	6.12	5.78	5.42	5.17	4.92	4.92	4.92	5.00	5.16	5.06	5.01	5.09	5.19	5.37	5.46	5.65	5.70	5.75	5.87	5.89	5.87	5.82
Delivered Prices																											
Residential	11.05	12.80	13.43	12.13	12.10	11.66	11.33	10.99	10.75	10.46	10.47	10.48	10.55	10.76	10.66	10.63	10.72	10.81	11.01	11.12	11.30	11.38	11.46	11.60	11.63	11.64	11.60
Commercial	9.69	11.54	11.72	10.52	10.47	9.99	9.64	9.27	9.01	8.70	8.68	8.67	8.72	8.89	8.79	8.73	8.81	8.86	9.03	9.11	9.26	9.31	9.36	9.48	9.48	9.44	9.38
Industrial 4/	6.67	8.41	7.67	7.54	7.51	7.00	6.66	6.29	6.44	6.21	6.23	6.26	6.40	6.59	6.58	6.60	6.74	6.87	7.11	7.26	7.50	7.64	7.78	7.98	8.09	8.20	8.26
Electric Power 7/	6.26	8.41	7.17	7.25	7.27	6.78	6.43	6.09	6.21	5.95	5.97	6.02	6.14	6.35	6.28	6.30	6.45	6.58	6.82	6.96	7.18	7.31	7.42	7.62	7.71	7.78	7.82
Transportation 12/	12.30	14.16	11.29	11.42	11.30	11.53	13.43	13.02	13.14	12.86	12.80	12.83	12.90	13.06	13.00	13.07	13.10	13.20	13.44	13.53	13.75	13.91	13.97	14.22	14.26	14.42	14.54
Average 13/	8.06	9.93	9.41	8.97	8.93	8.43	8.09	7.73	7.74	7.49	7.50	7.51	7.62	7.82	7.76	7.76	7.88	7.99	8.21	8.34	8.55	8.66	8.78	8.96	9.04	9.11	9.14

1/ Marketed production (wet) minus extraction losses.
2/ Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
3/ Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida.
4/ Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
5/ Includes any natural gas used in the process of converting natural gas to liquid fuel that is not actually converted..
6/ Includes any natural gas that is converted into liquid fuel.
7/ Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
8/ Compressed natural gas used as vehicle fuel.
9/ Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
10/ Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2004 and 2005 values include net storage injections.
11/ Represents lower 48 onshore and offshore supplies.
12/ Compressed natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
13/ Weighted average prices. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
Sources: 2004 supply values; and lease, plant, and pipeline fuel consumption: Energy Information Administration (EIA), Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005). 2005 supply values; and lease, plant, and pipeline fuel consumption; and wellhead price: EIA, Natural Gas Monthly, DOE/EIA-0130(2006/04) (Washington, DC, April 2006). Other 2004 and 2005 consumption based on: EIA, Annual Energy Review 2005, DOE/EIA-0384(2005) (Washington, DC, July 2006). 2004 wellhead price: Minerals Management Service and EIA, Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005). 2004 residential and commercial delivered prices: EIA, Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005). 2005 residential and commercial delivered prices: EIA, Natural Gas Monthly, DOE/EIA-0130 (2006/04) (Washington, DC, April 2006). 2004 and 2005 electric power prices: EIA, Electric Power Monthly, DOE/EIA-0226, May 2005 through April 2006, Table 4.11.A. 2004 and 2005 industrial delivered prices are estimated based on: EIA, Manufacturing Energy Consumption Survey 1994 and industrial and wellhead prices from the Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005) and the Natural Gas Monthly, DOE/EIA-0130(2006/04) (Washington, DC, April 2006). 2004 transportation sector delivered prices are based on: EIA, Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005) and estimated state taxes, federal taxes, and dispensing costs or charges. 2005 transportation sector delivered prices are model results. Projections: EIA, AEO2007 National Energy Modeling System run s280straw.d060207a.

HEARING EXHIBIT 00000169

Table 13. Natural Gas Supply, Disposition, and Prices
(Trillion cubic feet, unless otherwise noted)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Production																											
Dry Gas Production 1/	18.76	18.23	18.58	19.04	19.52	19.53	19.50	19.51	19.45	19.30	19.65	19.58	19.56	19.52	20.07	20.52	20.62	20.75	20.74	20.59	20.47	20.26	20.23	20.17	20.26	20.31	20.27
Supplemental Natural Gas 2/	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Net Imports	3.40	3.57	3.29	3.41	3.89	4.32	4.68	5.08	5.09	5.40	5.32	5.61	5.74	5.52	5.33	4.96	5.03	4.77	4.64	4.75	4.77	4.85	4.80	4.74	4.91	4.95	5.51
Pipeline 3/	2.81	3.01	2.74	2.65	2.78	2.87	2.82	2.71	2.70	2.89	2.76	2.65	2.57	2.32	2.10	1.83	1.57	1.48	1.33	1.19	1.17	1.03	0.91	0.81	0.89	0.93	0.88
Liquefied Natural Gas	0.59	0.57	0.55	0.76	1.11	1.45	1.86	2.37	2.39	2.50	2.57	2.95	3.17	3.20	3.23	3.13	3.46	3.29	3.31	3.55	3.60	3.81	3.89	3.94	4.03	4.03	4.63
Total Supply	22.22	21.87	21.93	22.53	23.48	23.92	24.25	24.66	24.61	24.76	25.05	25.25	25.38	25.11	25.47	25.55	25.72	25.60	25.45	25.41	25.32	25.18	25.10	24.98	25.24	25.34	25.85
Consumption by Sector																											
Residential	4.87	4.84	4.48	4.69	4.96	5.00	5.03	5.07	5.11	5.13	5.14	5.16	5.18	5.17	5.18	5.19	5.21	5.21	5.21	5.20	5.22	5.20	5.20	5.19	5.20	5.18	5.18
Commercial	3.13	3.05	2.92	3.02	3.10	3.16	3.21	3.28	3.35	3.42	3.47	3.52	3.57	3.61	3.65	3.70	3.74	3.79	3.84	3.89	3.94	3.99	4.05	4.11	4.17	4.24	4.32
Industrial 4/	7.22	6.64	6.76	7.09	7.39	7.56	7.65	7.59	7.67	7.68	7.65	7.73	7.91	7.72	7.89	7.84	8.07	8.01	8.02	8.18	8.19	8.23	8.30	8.33	8.57	8.49	8.62
Natural Gas-to-Liquids Heat and Power 5/	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas to Liquids Production 6/	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electric Power 7/	5.51	5.83	5.89	5.85	6.32	6.46	6.63	6.99	6.75	6.80	7.01	7.06	6.93	6.83	6.88	6.87	6.71	6.59	6.39	6.16	6.02	5.81	5.61	5.42	5.37	5.49	5.80
Transportation 8/	0.03	0.03	0.04	0.05	0.05	0.05	0.06	0.06	0.07	0.07	0.07	0.08	0.08	0.08	0.09	0.09	0.09	0.10	0.10	0.10	0.10	0.11	0.11	0.11	0.12	0.12	0.12
Pipeline Fuel	0.57	0.56	0.55	0.61	0.63	0.64	0.65	0.66	0.67	0.67	0.68	0.69	0.69	0.68	0.72	0.76	0.77	0.78	0.78	0.78	0.77	0.77	0.77	0.76	0.76	0.77	0.77
Lease and Plant Fuel 9/	1.10	1.07	1.09	1.06	1.08	1.08	1.07	1.07	1.06	1.05	1.07	1.07	1.07	1.07	1.12	1.16	1.16	1.17	1.16	1.15	1.14	1.12	1.12	1.11	1.11	1.11	1.11
Total	22.43	22.02	21.72	22.58	23.53	23.95	24.30	24.71	24.66	24.81	25.10	25.31	25.43	25.16	25.53	25.61	25.77	25.65	25.50	25.46	25.38	25.24	25.16	25.04	25.30	25.40	25.92
Discrepancy 10/	-0.20	-0.15	0.21	-0.05	-0.05	-0.03	-0.05	-0.05	-0.05	-0.05	0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.06	-0.06	-0.06	-0.06	-0.06	-0.06	-0.06	-0.06	-0.06
Natural Gas Prices																											
(2005 dollars per million Btu)																											
Henry Hub Spot Price	6.08	8.60	7.07	7.16	7.25	6.72	6.41	6.04	5.68	5.45	5.47	5.40	5.49	5.59	5.57	5.52	5.56	5.58	5.70	5.79	5.91	5.96	6.08	6.21	6.34	6.40	6.45
Average Lower 48 Wellhead Price 11/	5.63	7.29	6.47	6.39	6.47	5.99	5.71	5.37	5.04	4.83	4.85	4.79	4.87	4.96	4.94	4.90	4.93	4.95	5.06	5.14	5.25	5.29	5.41	5.52	5.64	5.70	5.74
(2005 dollars per thousand cubic feet)																											
Average Lower 48 Wellhead Price 11/	5.80	7.51	6.67	6.58	6.66	6.17	5.88	5.53	5.19	4.98	5.00	4.93	5.02	5.11	5.09	5.05	5.08	5.10	5.21	5.29	5.41	5.45	5.57	5.69	5.81	5.87	5.91
Delivered Prices																											
Residential	11.05	12.80	13.43	12.13	12.16	11.70	11.42	11.10	10.78	10.52	10.56	10.50	10.58	10.69	10.68	10.65	10.70	10.70	10.83	10.95	11.03	11.10	11.25	11.39	11.53	11.61	11.68
Commercial	9.69	11.54	11.72	10.51	10.53	10.03	9.74	9.39	9.04	8.76	8.78	8.69	8.75	8.83	8.81	8.76	8.79	8.76	8.86	8.94	9.00	9.04	9.15	9.26	9.38	9.42	9.45
Industrial 4/	6.67	8.41	7.67	7.53	7.57	7.05	6.75	6.41	6.78	6.57	6.65	6.64	6.77	6.95	7.01	7.08	7.19	7.29	7.50	7.70	7.91	8.08	8.35	8.62	8.89	9.16	9.41
Electric Power 7/	6.26	8.41	7.17	7.25	7.33	6.82	6.55	6.24	6.55	6.32	6.43	6.42	6.54	6.69	6.78	6.82	6.94	7.03	7.21	7.38	7.58	7.74	7.97	8.22	8.52	8.78	9.09
Transportation 12/	12.30	14.16	11.29	11.41	11.34	11.55	13.50	13.13	13.46	13.20	13.21	13.18	13.28	13.38	13.43	13.51	13.56	13.62	13.86	13.98	14.17	14.38	14.57	14.84	15.14	15.34	15.63
Average 13/	8.06	9.93	9.41	8.97	8.98	8.47	8.17	7.84	7.95	7.72	7.79	7.75	7.86	8.01	8.05	8.08	8.17	8.23	8.41	8.57	8.73	8.86	9.08	9.29	9.51	9.69	9.86

1/ Marketed production (wet) minus extraction losses.
2/ Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
3/ Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida.
4/ Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
5/ Includes any natural gas used in the process of converting natural gas to liquid fuel that is not actually converted.
6/ Includes any natural gas that is converted into liquid fuel.
7/ Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
8/ Compressed natural gas used as vehicle fuel.
9/ Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
10/ Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2004 and 2005 values include net storage injections.
11/ Represents lower 48 onshore and offshore supplies.
12/ Compressed natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
13/ Weighted average prices. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
Sources: 2004 supply values; and lease, plant, and pipeline fuel consumption: Energy Information Administration (EIA), Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005). 2005 supply values; and lease, plant, and pipeline fuel consumption; and wellhead price: EIA, Natural Gas Monthly, DOE/EIA-0130(2006/04) (Washington, DC, April 2006). Other 2004 and 2005 consumption based on: EIA, Annual Energy Review 2005, DOE/EIA-0384(2005) (Washington, DC, July 2006). 2004 wellhead price: Minerals Management Service and EIA, Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005). 2004 residential and commercial delivered prices: EIA, Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005). 2005 residential and commercial delivered prices: EIA, Natural Gas Monthly, DOE/EIA-0130 (2006/04) (Washington, DC, April 2006). 2004 and 2005 electric power prices: EIA, Electric Power Monthly, DOE/EIA-0226, May 2005 through April 2006, Table 4.11.A. 2004 and 2005 industrial delivered prices are estimated based on: EIA, Manufacturing Energy Consumption Survey 1994 and industrial and wellhead prices from the Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005) and the Natural Gas Monthly, DOE/EIA-0130(2006/04) (Washington, DC, April 2006). 2004 transportation sector delivered prices are based on: EIA, Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005) and estimated state taxes, federal taxes, and dispensing costs or charges. 2005 transportation sector delivered prices are model results. Projections: EIA, AEO2007 National Energy Modeling System run s280nuc.d060207a.

HEARING EXHIBIT 2008-007

Table 13. Natural Gas Supply, Disposition, and Prices
(trillion cubic feet, unless otherwise noted)

Attachment POD-1 d Table 13 Natural Gas Supply, Disposition, and Prices S 280 Low Discount Case

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Production																											
Dry Gas Production 1/	18.76	18.23	18.58	19.06	19.44	19.55	19.46	19.63	19.39	19.34	19.49	19.58	19.51	19.44	19.91	20.38	20.49	20.58	20.40	20.38	20.18	20.03	19.94	19.92	19.83	19.83	19.68
Supplemental Natural Gas 2/	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Net Imports	3.40	3.57	3.29	3.39	3.86	4.30	4.66	5.13	5.07	5.41	5.21	5.50	5.55	5.34	5.05	4.64	4.53	4.39	4.51	4.34	4.32	4.26	4.21	4.24	4.15	4.09	4.16
Pipeline 3/	2.81	3.01	2.74	2.63	2.75	2.85	2.80	2.71	2.69	2.89	2.73	2.64	2.55	2.31	2.08	1.80	1.54	1.45	1.26	1.11	1.08	0.94	0.82	0.76	0.70	0.61	0.66
Liquefied Natural Gas	0.59	0.57	0.55	0.76	1.11	1.45	1.85	2.41	2.38	2.51	2.48	2.87	3.00	3.03	2.97	2.84	2.99	2.94	3.25	3.23	3.24	3.31	3.40	3.48	3.44	3.48	3.51
Total Supply	22.22	21.87	21.93	22.53	23.37	23.92	24.19	24.83	24.54	24.82	24.78	25.16	25.14	24.85	25.03	25.10	25.09	25.05	24.98	24.79	24.57	24.36	24.22	24.23	24.05	23.99	23.92
Consumption by Sector																											
Residential	4.87	4.84	4.48	4.89	4.97	5.00	5.03	5.06	5.11	5.13	5.15	5.16	5.18	5.17	5.18	5.20	5.23	5.22	5.22	5.22	5.23	5.22	5.21	5.21	5.22	5.20	5.21
Commercial	3.13	3.05	2.92	3.02	3.10	3.16	3.21	3.27	3.35	3.42	3.48	3.53	3.57	3.61	3.65	3.71	3.77	3.81	3.85	3.91	3.96	4.01	4.06	4.11	4.17	4.24	4.32
Industrial 4/	7.22	6.64	6.76	7.08	7.24	7.56	7.50	7.65	7.65	7.71	7.67	7.70	7.76	7.77	7.94	7.96	7.97	8.09	8.18	8.15	8.18	8.27	8.35	8.66	8.55	8.65	8.66
Natural Gas-to-Liquids Heat and Power 5/	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas to Liquids Production 6/	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electric Power 7/	5.51	5.83	5.89	5.87	6.35	6.48	6.73	7.10	6.69	6.83	6.72	6.98	6.84	6.53	6.40	6.29	6.18	5.95	5.79	5.57	5.28	4.94	4.70	4.36	4.22	4.01	3.86
Transportation 8/	0.03	0.03	0.04	0.05	0.05	0.05	0.06	0.06	0.07	0.07	0.07	0.08	0.08	0.08	0.09	0.09	0.09	0.10	0.10	0.10	0.11	0.11	0.11	0.11	0.12	0.12	0.12
Pipeline Fuel	0.57	0.56	0.55	0.62	0.63	0.64	0.65	0.66	0.67	0.67	0.67	0.69	0.69	0.68	0.72	0.75	0.76	0.76	0.76	0.76	0.75	0.75	0.74	0.74	0.74	0.74	0.73
Lease and Plant Fuel 9/	1.10	1.07	1.09	1.06	1.08	1.08	1.07	1.07	1.06	1.05	1.06	1.07	1.07	1.07	1.11	1.15	1.16	1.16	1.15	1.14	1.13	1.12	1.11	1.10	1.09	1.09	1.08
Total	22.43	22.02	21.72	22.58	23.42	23.97	24.24	24.88	24.59	24.88	24.83	25.21	25.19	24.91	25.09	25.15	25.15	25.10	25.04	24.85	24.63	24.42	24.28	24.29	24.11	24.05	23.98
Discrepancy 10/	-0.20	-0.15	0.21	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.06	-0.05	-0.05	-0.06	-0.06	-0.06	-0.06	-0.06	-0.06	-0.06	-0.06	-0.06	-0.06	-0.06
Natural Gas Prices																											
(2005 dollars per million Btu)																											
Henry Hub Spot Price	6.08	8.60	7.07	7.18	7.18	6.73	6.39	6.12	5.66	5.47	5.38	5.38	5.47	5.54	5.47	5.41	5.47	5.47	5.46	5.62	5.72	5.81	5.91	6.07	6.07	6.08	6.06
Average Lower 48 Wellhead Price 11/	5.63	7.29	6.47	6.41	6.41	5.99	5.69	5.45	5.03	4.85	4.77	4.77	4.85	4.91	4.85	4.80	4.85	4.85	4.84	4.99	5.08	5.16	5.25	5.40	5.40	5.40	5.38
(2005 dollars per thousand cubic feet)																											
Average Lower 48 Wellhead Price 11/	5.80	7.51	6.67	6.60	6.60	6.17	5.86	5.61	5.18	5.00	4.91	4.91	5.00	5.06	5.00	4.94	5.00	5.00	4.98	5.14	5.23	5.31	5.41	5.56	5.56	5.56	5.55
Delivered Prices																											
Residential	11.05	12.80	13.43	12.13	12.10	11.70	11.41	11.17	10.76	10.54	10.48	10.48	10.56	10.66	10.60	10.55	10.62	10.61	10.61	10.79	10.84	10.96	11.08	11.25	11.26	11.29	11.28
Commercial	9.69	11.54	11.72	10.51	10.47	10.03	9.72	9.46	9.02	8.78	8.69	8.67	8.73	8.80	8.73	8.66	8.71	8.66	8.63	8.78	8.82	8.90	8.99	9.13	9.11	9.10	9.07
Industrial 4/	6.67	8.41	7.67	7.54	7.52	7.05	6.75	6.47	6.91	6.74	6.70	6.73	6.84	6.96	6.93	6.93	7.04	7.05	7.06	7.28	7.38	7.52	7.68	7.86	7.94	8.00	8.05
Electric Power 7/	6.26	8.41	7.17	7.26	7.27	6.83	6.55	6.33	6.68	6.50	6.43	6.49	6.58	6.67	6.63	6.59	6.62	6.64	6.75	6.86	6.92	7.04	7.16	7.33	7.38	7.42	7.44
Transportation 12/	12.30	14.16	11.29	11.42	11.29	11.55	13.49	13.20	13.59	13.37	13.26	13.27	13.34	13.40	13.36	13.39	13.40	13.40	13.48	13.59	13.71	13.86	13.93	14.14	14.24	14.28	14.37
Average 13/	8.06	9.93	9.41	8.97	8.93	8.47	8.17	7.90	8.03	7.84	7.79	7.80	7.90	8.02	7.97	7.95	8.03	8.04	8.08	8.26	8.35	8.49	8.63	8.81	8.87	8.91	8.94

1/ Marketed production (wet) minus extraction losses.
2/ Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
3/ Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida.
4/ Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
5/ Includes any natural gas used in the process of converting natural gas to liquid fuel that is not actually converted.
6/ Includes any natural gas that is converted into liquid fuel.
7/ Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
8/ Compressed natural gas used as vehicle fuel.
9/ Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
10/ Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2004 and 2005 values include net storage injections.
11/ Represents lower 48 onshore and offshore supplies.
12/ Compressed natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
13/ Weighted average prices. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
Sources: 2004 supply values; and lease, plant, and pipeline fuel consumption: Energy Information Administration (EIA), Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005). 2005 supply values; and lease, plant, and pipeline fuel consumption; and wellhead price: EIA, Natural Gas Monthly, DOE/EIA-0130(2006/04) (Washington, DC, April 2006). Other 2004 and 2005 consumption based on: EIA, Annual Energy Review 2005, DOE/EIA-0384(2005) (Washington, DC, July 2006). 2004 wellhead price: Minerals Management Service and EIA, Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005). 2004 residential and commercial delivered prices: EIA, Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005). 2005 residential and commercial delivered prices: EIA, Natural Gas Monthly, DOE/EIA-0130 (2006/04) (Washington, DC, April 2006). 2004 and 2005 electric power prices: EIA, Electric Power Monthly, DOE/EIA-0226, May 2005 through April 2006, Table 4.11.A. 2004 and 2005 industrial delivered prices are estimated based on: EIA, Manufacturing Energy Consumption Survey 1994 and industrial and wellhead prices from the Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005) and the Natural Gas Monthly, DOE/EIA-0130(2006/04) (Washington, DC, April 2006). 2004 transportation sector delivered prices are based on: EIA, Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005) and estimated state taxes, federal taxes, and dispensing costs or charges. 2005 transportation sector delivered prices are model results. Projections: EIA, AEO2007 National Energy Modeling System run s280r4.d061507a.

HEARING EXHIBIT - 00000165

Table 13. Natural Gas Supply, Disposition, and Prices
(trillion cubic feet, unless otherwise noted)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Production																											
Dry Gas Production 1/	18.36	18.23	18.58	19.04	19.43	19.46	19.47	19.51	19.45	19.31	19.56	19.62	19.59	19.65	20.08	20.60	20.68	20.86	20.82	20.62	20.56	20.41	20.31	20.14	20.07	20.14	20.03
Supplemental Natural Gas 2/	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Net Imports	3.40	3.57	3.29	3.38	3.85	4.25	4.60	5.05	5.07	5.37	5.21	5.56	5.74	5.66	5.38	5.06	5.15	5.00	4.83	4.89	4.92	4.97	4.87	4.81	4.69	4.52	4.59
Pipeline 3/	2.81	3.01	2.74	2.62	2.73	2.82	2.76	2.67	2.68	2.87	2.70	2.61	2.56	2.36	2.16	1.91	1.67	1.59	1.44	1.29	1.26	1.15	1.03	1.01	1.00	0.86	0.81
Liquefied Natural Gas	0.59	0.57	0.55	0.76	1.11	1.43	1.84	2.38	2.39	2.51	2.51	2.94	3.18	3.29	3.22	3.15	3.48	3.41	3.39	3.60	3.65	3.82	3.85	3.80	3.69	3.66	3.78
Total Supply	22.22	21.87	21.93	22.49	23.35	23.78	24.14	24.65	24.59	24.75	24.84	25.25	25.40	25.37	25.54	25.73	25.90	25.93	25.72	25.58	25.55	25.45	25.26	25.02	24.83	24.73	24.69
Consumption by Sector																											
Residential	4.87	4.84	4.48	4.89	4.97	5.00	5.03	5.07	5.11	5.13	5.15	5.16	5.18	5.16	5.17	5.19	5.21	5.20	5.20	5.20	5.21	5.19	5.19	5.19	5.21	5.19	5.20
Commercial	3.13	3.05	2.92	3.02	3.11	3.16	3.21	3.28	3.35	3.42	3.48	3.53	3.57	3.60	3.64	3.69	3.74	3.79	3.83	3.88	3.93	3.98	4.02	4.08	4.14	4.21	4.28
Industrial 4/	7.22	6.64	6.76	7.03	7.25	7.43	7.55	7.61	7.71	7.70	7.67	7.71	7.74	7.93	7.93	7.87	7.94	8.15	8.06	8.10	8.22	8.28	8.35	8.44	8.54	8.77	8.88
Natural Gas-to-Liquids Heat and Pow	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas to Liquids Production 6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electric Power 7/	5.51	5.83	5.89	5.87	6.32	6.46	6.62	6.96	6.68	6.77	6.79	7.07	7.13	6.88	6.92	7.02	7.04	6.80	6.64	6.43	6.23	6.05	5.75	5.38	5.03	4.64	4.42
Transportation 8/	0.03	0.03	0.04	0.05	0.05	0.05	0.06	0.06	0.07	0.07	0.07	0.08	0.08	0.08	0.09	0.09	0.09	0.10	0.10	0.10	0.10	0.11	0.11	0.11	0.12	0.12	0.12
Pipeline Fuel	0.57	0.56	0.55	0.61	0.63	0.64	0.65	0.66	0.67	0.67	0.67	0.69	0.69	0.69	0.72	0.76	0.77	0.78	0.78	0.77	0.77	0.77	0.76	0.76	0.75	0.75	0.74
Lease and Plant Fuel 9/	1.10	1.07	1.09	1.06	1.08	1.08	1.07	1.07	1.06	1.05	1.07	1.07	1.07	1.08	1.12	1.16	1.17	1.17	1.17	1.15	1.14	1.13	1.12	1.11	1.10	1.10	1.09
Total	22.43	22.02	21.72	22.54	23.40	23.83	24.19	24.71	24.65	24.80	24.89	25.30	25.46	25.42	25.59	25.78	25.96	25.98	25.78	25.64	25.61	25.51	25.31	25.07	24.89	24.79	24.74
Discrepancy 10/	-0.20	-0.15	0.21	-0.05	0.05	-0.05	-0.05	-0.05	-0.05	-0.05	0.05	-0.05	0.05	0.05	-0.05	-0.05	-0.05	-0.05	-0.06	-0.06	-0.06	-0.06	-0.05	-0.06	-0.06	-0.06	-0.06
Natural Gas Prices																											
(2005 dollars per million Btu)																											
Henry Hub Spot Price	6.08	8.60	7.07	7.16	7.17	6.65	6.38	6.06	5.69	5.46	5.42	5.43	5.55	5.70	5.61	5.56	5.62	5.66	5.75	5.79	5.94	6.05	6.15	6.16	6.13	6.17	6.19
Average Lower 48 Wellhead Price 1	5.63	7.29	6.47	6.39	6.40	5.92	5.68	5.39	5.05	4.84	4.81	4.82	4.93	5.06	4.98	4.94	4.99	5.02	5.11	5.15	5.28	5.38	5.47	5.48	5.45	5.49	5.50
(2005 dollars per thousand cubic feet)																											
Average Lower 48 Wellhead Price 1	5.80	7.51	6.67	6.58	6.59	6.10	5.85	5.55	5.21	4.99	4.95	4.96	5.08	5.22	5.12	5.08	5.14	5.17	5.26	5.30	5.44	5.54	5.63	5.64	5.61	5.65	5.67
Delivered Prices																											
Residential	11.05	12.80	13.43	12.10	12.09	11.63	11.39	11.11	10.79	10.53	10.50	10.52	10.63	10.82	10.73	10.71	10.78	10.80	10.91	10.97	11.08	11.22	11.33	11.36	11.34	11.39	11.43
Commercial	9.69	11.54	11.72	10.49	10.46	9.96	9.70	9.40	9.05	8.77	8.72	8.71	8.80	8.95	8.85	8.82	8.86	8.85	8.93	8.95	9.05	9.15	9.23	9.23	9.19	9.21	9.21
Industrial 4/	6.67	8.41	7.67	7.51	7.50	7.00	6.73	6.43	6.40	6.58	6.58	6.61	6.73	6.89	6.84	6.92	7.04	7.03	7.06	7.03	7.09	7.27	7.42	7.51	7.56	7.66	7.77
Electric Power 7/	6.26	8.41	7.17	7.24	7.25	6.76	6.51	6.26	6.56	6.33	6.33	6.38	6.50	6.65	6.59	6.62	6.76	6.74	6.74	6.70	6.73	6.89	7.01	7.06	7.07	7.16	7.23
Transportation 12/	12.30	14.16	11.29	11.40	11.28	11.49	13.47	13.14	13.47	13.21	13.13	13.15	13.23	13.34	13.27	13.34	13.39	13.37	13.40	13.31	13.37	13.57	13.64	13.78	13.87	13.95	14.11
Average 13/	8.06	9.93	9.41	8.95	8.92	8.41	8.15	7.85	7.97	7.73	7.72	7.74	7.85	8.02	7.95	7.98	8.08	8.08	8.14	8.15	8.23	8.39	8.53	8.60	8.63	8.72	8.80

1/ Marketed production (wet) minus extraction losses.
2/ Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
3/ Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida.
4/ Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
5/ Includes any natural gas used in the process of converting natural gas to liquid fuel that is not actually converted..
6/ Includes any natural gas that is converted into liquid fuel.
7/ Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
8/ Compressed natural gas used as vehicle fuel.
9/ Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
10/ Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2004 and 2005 values include net storage injections.
11/ Represents lower 48 onshore and offshore supplies.
12/ Compressed natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
13/ Weighted average prices. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
Sources: 2004 supply values; and lease, plant, and pipeline fuel consumption: Energy Information Administration (EIA), Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005). 2005 supply values; and lease, plant, and pipeline fuel consumption; and wellhead price: EIA, Natural Gas Monthly, DOE/EIA-0130(2006/04) (Washington, DC, April 2006). Other 2004 and 2005 consumption based on: EIA, Annual Energy Review 2005, DOE/EIA-0384(2005) (Washington, DC, July 2006). 2004 wellhead price: Minerals Management Service and EIA, Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005). 2004 residential and commercial delivered prices: EIA, Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005). 2005 residential and commercial delivered prices: EIA, Natural Gas Monthly, DOE/EIA-0130 (2006/04) (Washington, DC, April 2006). 2004 and 2005 electric power prices: EIA, Electric Power Monthly, DOE/EIA-0226, May 2005 through April 2006, Table 4.11.A. 2004 and 2005 industrial delivered prices are estimated based on: EIA, Manufacturing Energy Consumption Survey 1994 and industrial and wellhead prices from the Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005) and the Natural Gas Monthly, DOE/EIA-0130(2006/04) (Washington, DC, April 2006). 2004 transportation sector delivered prices are based on: EIA, Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005) and estimated state taxes, federal taxes, and dispensing costs or charges. 2005 transportation sector delivered prices are model results. Projections: EIA, AEO2007 National Energy Modeling System run s280vhioff25.d061607a.

HEARING EXHIBIT - 00000166

Table 13. Natural Gas Supply, Disposition, and Prices
(trillion cubic feet, unless otherwise noted)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Production																											
Dry Gas Production 1/	18.76	18.23	18.58	19.14	19.50	19.46	19.51	19.55	19.41	19.36	19.52	19.55	19.44	19.45	19.88	20.42	20.42	20.59	20.57	20.37	20.24	20.11	19.97	19.79	19.80	19.84	19.78
Supplemental Natural Gas 2/	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Net Imports	3.40	3.57	3.29	3.42	3.90	4.29	4.68	5.10	5.07	5.42	5.23	5.46	5.42	5.25	4.93	4.65	4.88	4.74	4.59	4.48	4.48	4.40	4.27	4.13	3.98	4.03	3.98
Pipeline 3/	2.81	3.01	2.74	2.66	2.79	2.86	2.82	2.71	2.69	2.90	2.74	2.63	2.53	2.28	2.04	1.78	1.51	1.41	1.26	1.11	1.09	0.96	0.83	0.73	0.67	0.58	0.54
Liquefied Natural Gas	0.59	0.57	0.55	0.76	1.11	1.43	1.86	2.39	2.38	2.52	2.49	2.83	2.88	2.97	2.89	2.88	3.36	3.33	3.33	3.36	3.39	3.44	3.44	3.40	3.31	3.45	3.44
Total Supply	22.22	21.87	21.93	22.63	23.47	23.82	24.26	24.72	24.56	24.86	24.82	25.07	24.93	24.77	24.89	25.14	25.36	25.40	25.23	24.92	24.79	24.58	24.31	23.99	23.86	23.94	23.84
Consumption by Sector																											
Residential	4.87	4.84	4.48	4.88	4.96	5.00	5.03	5.06	5.11	5.13	5.15	5.16	5.19	5.18	5.19	5.20	5.22	5.22	5.22	5.21	5.23	5.21	5.21	5.21	5.22	5.21	5.21
Commercial	3.13	3.05	2.92	3.02	3.10	3.16	3.21	3.28	3.35	3.42	3.48	3.53	3.57	3.61	3.66	3.71	3.76	3.81	3.85	3.90	3.95	4.00	4.06	4.12	4.19	4.26	4.34
Industrial 4/	7.22	6.64	6.76	7.18	7.38	7.44	7.63	7.61	7.65	7.86	7.82	7.82	7.80	7.79	7.90	7.94	8.05	8.15	8.26	8.12	8.22	8.27	8.47	8.56	8.63	8.69	8.58
Natural Gas-to-Liquids Heat and Power 5/	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas to Liquids Production 6/	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electric Power 7/	5.51	5.83	5.89	5.87	6.33	6.49	6.66	7.03	6.71	6.71	6.62	6.78	6.59	6.41	6.28	6.35	6.38	6.26	5.93	5.73	5.45	5.17	4.66	4.22	3.94	3.91	3.84
Transportation 8/	0.03	0.03	0.04	0.05	0.05	0.05	0.06	0.06	0.07	0.07	0.07	0.08	0.08	0.08	0.09	0.09	0.09	0.10	0.10	0.10	0.10	0.11	0.11	0.11	0.12	0.12	0.12
Pipeline Fuel	0.57	0.56	0.55	0.62	0.63	0.64	0.65	0.66	0.67	0.67	0.67	0.68	0.68	0.68	0.72	0.75	0.76	0.77	0.77	0.76	0.76	0.75	0.74	0.73	0.73	0.73	0.73
Lease and Plant Fuel 9/	1.10	1.07	1.09	1.07	1.08	1.08	1.07	1.07	1.06	1.05	1.06	1.07	1.07	1.07	1.11	1.15	1.15	1.16	1.16	1.14	1.13	1.12	1.11	1.10	1.09	1.09	1.08
Total	22.43	22.02	21.73	22.68	23.53	23.86	24.31	24.77	24.61	24.91	24.87	25.13	24.98	24.83	24.94	25.20	25.42	25.45	25.28	24.97	24.85	24.64	24.37	24.05	23.92	24.00	23.89
Discrepancy 10/	-0.20	-0.15	0.21	-0.05	-0.05	-0.04	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.06	-0.06	-0.06	-0.05	-0.06	-0.06	-0.06	-0.06
Natural Gas Prices																											
(2005 dollars per million Btu)																											
Henry Hub Spot Price	6.08	8.60	7.07	7.24	7.25	6.65	6.40	6.07	5.66	5.48	5.40	5.35	5.41	5.52	5.45	5.43	5.43	5.47	5.59	5.66	5.77	5.89	5.95	5.97	5.99	6.04	6.11
Average Lower 48 Wellhead Price 11/	5.63	7.29	6.47	6.47	6.47	5.93	5.70	5.40	5.02	4.86	4.78	4.75	4.80	4.90	4.83	4.81	4.82	4.85	4.96	5.02	5.13	5.23	5.29	5.31	5.33	5.37	5.43
(2005 dollars per thousand cubic feet)																											
Average Lower 48 Wellhead Price 11/	5.80	7.51	6.67	6.66	6.66	6.10	5.87	5.56	5.17	5.01	4.93	4.89	4.94	5.05	4.98	4.96	4.96	4.99	5.11	5.18	5.28	5.39	5.45	5.47	5.48	5.53	5.59
Delivered Prices																											
Residential	11.05	12.80	13.43	12.19	12.17	11.64	11.42	11.13	10.75	10.56	10.50	10.46	10.51	10.64	10.58	10.57	10.59	10.59	10.74	10.82	10.91	11.04	11.13	11.16	11.18	11.25	11.33
Commercial	9.69	11.54	11.72	10.57	10.54	9.97	9.73	9.41	9.02	8.80	8.71	8.65	8.68	8.78	8.70	8.68	8.67	8.65	8.76	8.81	8.88	8.97	9.03	9.03	9.03	9.07	9.12
Industrial 4/	6.67	8.41	7.67	7.59	7.57	7.00	6.74	6.44	6.75	6.58	6.54	6.53	6.66	6.84	6.86	6.94	7.03	7.10	7.32	7.50	7.70	7.93	8.11	8.27	8.45	8.67	8.95
Electric Power 7/	6.26	8.41	7.17	7.32	7.33	6.76	6.55	6.28	6.52	6.34	6.28	6.30	6.37	6.54	6.53	6.60	6.70	6.78	6.95	7.10	7.26	7.47	7.61	7.74	7.87	8.09	8.34
Transportation 12/	12.30	14.16	11.29	11.46	11.34	11.50	13.50	13.16	13.43	13.23	13.12	13.09	13.16	13.28	13.29	13.38	13.39	13.46	13.70	13.80	13.99	14.23	14.36	14.54	14.75	14.93	15.22
Average 13/	8.06	9.93	9.41	9.02	8.98	8.41	8.17	7.86	7.93	7.74	7.69	7.68	7.77	7.94	7.92	7.96	8.02	8.07	8.26	8.41	8.56	8.75	8.90	9.02	9.14	9.29	9.47

1/ Marketed production (wet) minus extraction losses.
2/ Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
3/ Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida.
4/ Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
5/ Includes any natural gas used in the process of converting natural gas to liquid fuel that is not actually converted..
6/ Includes any natural gas that is converted into liquid fuel.
7/ Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
8/ Compressed natural gas used as vehicle fuel.
9/ Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
10/ Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2004 and 2005 values include net storage injections.
11/ Represents lower 48 onshore and offshore supplies.
12/ Compressed natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
13/ Weighted average prices. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
Sources: 2004 supply values; and lease, plant, and pipeline fuel consumption: Energy Information Administration (EIA), Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005). 2005 supply values; and lease, plant, and pipeline fuel consumption; and wellhead price: EIA, Natural Gas Monthly, DOE/EIA-0130(2006/04) (Washington, DC, April 2006). Other 2004 and 2005 consumption based on: EIA, Annual Energy Review 2005, DOE/EIA-0384(2005) (Washington, DC, July 2006). 2004 wellhead price: Minerals Management Service and EIA, Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005). 2004 residential and commercial delivered prices: EIA, Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005). 2005 residential and commercial delivered prices: EIA, Natural Gas Monthly, DOE/EIA-0130 (2006/04) (Washington, DC, April 2006). 2004 and 2005 electric power prices: EIA, Electric Power Monthly, DOE/EIA-0226, May 2005 through April 2006, Table 4.11.A. 2004 and 2005 industrial delivered prices are estimated based on: EIA, Manufacturing Energy Consumption Survey 1994 and industrial and wellhead prices from the Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005) and the Natural Gas Monthly, DOE/EIA-0130(2006/04) (Washington, DC, April 2006). 2004 transportation sector delivered prices are based on: EIA, Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005) and estimated state taxes, federal taxes, and dispensing costs or charges. 2005 transportation sector delivered prices are model results. Projections: EIA, AEO2007 National Energy Modeling System run s280cc70.d060207a.

HEARING EXHIBIT - 00000167

Table 13. Natural Gas Supply, Disposition, and Prices
(trillion cubic feet, unless otherwise noted)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Production																											
Dry Gas Production 1/	18.76	18.23	18.58	19.05	19.43	19.49	19.50	19.53	19.41	19.26	19.50	19.49	19.44	19.50	19.99	20.43	20.36	20.60	20.60	20.49	20.33	20.16	20.05	19.87	19.90	19.80	19.82
Supplemental Natural Gas 2/	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Net Imports	3.40	3.57	3.29	3.41	3.87	4.28	4.65	5.07	5.08	5.36	5.21	5.42	5.47	5.36	5.10	4.76	4.89	4.80	4.68	4.62	4.59	4.45	4.32	4.16	4.09	4.10	4.21
Pipeline 3/	2.81	3.01	2.74	2.65	2.75	2.84	2.79	2.69	2.70	2.88	2.73	2.62	2.53	2.29	2.09	1.81	1.53	1.45	1.30	1.17	1.14	1.00	0.86	0.74	0.68	0.68	0.76
Liquefied Natural Gas	0.59	0.57	0.55	0.76	1.11	1.44	1.86	2.38	2.38	2.48	2.48	2.80	2.94	3.07	3.02	2.95	3.37	3.35	3.38	3.45	3.45	3.46	3.46	3.42	3.41	3.42	3.46
Total Supply	22.22	21.87	21.93	22.53	23.37	23.84	24.22	24.67	24.56	24.69	24.78	24.99	24.98	24.93	25.16	25.26	25.33	25.47	25.35	25.19	24.99	24.68	24.44	24.09	24.07	23.97	24.10
Consumption by Sector																											
Residential	4.87	4.84	4.48	4.89	4.97	5.00	5.03	5.07	5.11	5.13	5.15	5.16	5.19	5.17	5.18	5.19	5.22	5.21	5.21	5.21	5.22	5.21	5.21	5.21	5.22	5.21	5.21
Commercial	3.13	3.05	2.92	3.02	3.10	3.16	3.21	3.28	3.31	3.36	3.40	3.45	3.48	3.51	3.55	3.58	3.62	3.66	3.69	3.72	3.75	3.79	3.82	3.86	3.90	3.95	3.99
Industrial 4/	7.22	6.64	6.76	7.08	7.25	7.49	7.62	7.63	7.65	7.65	7.68	7.79	7.77	7.87	7.99	8.02	7.95	8.07	8.07	8.18	8.24	8.21	8.31	8.38	8.65	8.51	8.55
Natural Gas-to-Liquids Heat and Power 5/	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas to Liquids Production 6/	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electric Power 7/	5.51	5.83	5.89	5.87	6.34	6.47	6.64	6.96	6.74	6.82	6.79	6.81	6.76	6.59	6.58	6.51	6.58	6.54	6.39	6.11	5.83	5.55	5.19	4.75	4.41	4.43	4.48
Transportation 8/	0.03	0.03	0.04	0.05	0.05	0.05	0.06	0.06	0.07	0.07	0.07	0.08	0.08	0.08	0.09	0.09	0.09	0.10	0.10	0.10	0.10	0.11	0.11	0.11	0.12	0.12	0.12
Pipeline Fuel	0.57	0.56	0.55	0.62	0.63	0.64	0.65	0.66	0.67	0.67	0.67	0.68	0.68	0.68	0.72	0.75	0.76	0.78	0.77	0.77	0.76	0.75	0.75	0.74	0.73	0.73	0.73
Lease and Plant Fuel 9/	1.10	1.07	1.09	1.06	1.08	1.08	1.07	1.07	1.06	1.05	1.06	1.07	1.07	1.07	1.11	1.15	1.15	1.16	1.16	1.15	1.13	1.12	1.11	1.10	1.10	1.09	1.09
Total	22.43	22.02	21.73	22.58	23.42	23.89	24.27	24.72	24.61	24.75	24.83	25.04	25.03	24.98	25.21	25.31	25.38	25.52	25.40	25.24	25.05	24.74	24.50	24.15	24.13	24.03	24.16
Discrepancy 10/	-0.20	-0.15	0.21	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	0.05	-0.05	-0.06	-0.05	-0.06	-0.05	-0.06	-0.06	-0.06	-0.06	-0.06	-0.06	-0.06
Natural Gas Prices																											
(2005 dollars per million Btu)																											
Henry Hub Spot Price	6.08	8.60	7.07	7.17	7.17	6.68	6.41	6.06	5.66	5.42	5.37	5.33	5.43	5.59	5.53	5.47	5.41	5.49	5.63	5.77	5.85	5.90	5.98	6.01	6.04	5.99	6.09
Average Lower 48 Wellhead Price 11/	5.63	7.29	6.47	6.40	6.40	5.95	5.71	5.39	5.02	4.81	4.76	4.73	4.82	4.96	4.91	4.85	4.80	4.87	5.00	5.12	5.20	5.25	5.32	5.34	5.37	5.32	5.41
(2005 dollars per thousand cubic feet)																											
Average Lower 48 Wellhead Price 11/	5.80	7.51	6.67	6.59	6.59	6.13	5.88	5.55	5.18	4.95	4.91	4.87	4.96	5.11	5.05	4.99	4.95	5.02	5.15	5.28	5.35	5.40	5.48	5.50	5.53	5.48	5.58
Delivered Prices																											
Residential	11.05	12.80	13.43	12.12	12.09	11.65	11.42	11.12	10.77	10.50	10.48	10.44	10.52	10.70	10.66	10.60	10.57	10.63	10.78	10.93	10.97	11.05	11.15	11.19	11.22	11.19	11.29
Commercial	9.69	11.54	11.72	10.51	10.46	9.99	9.73	9.40	9.75	9.50	9.49	9.47	9.57	9.79	9.80	9.82	9.85	9.98	10.20	10.42	10.57	10.74	10.95	11.11	11.29	11.40	11.67
Industrial 4/	6.67	8.41	7.67	7.53	7.51	7.01	6.75	6.43	6.76	6.54	6.54	6.53	6.65	6.85	6.88	6.92	6.97	7.11	7.33	7.55	7.71	7.88	8.09	8.25	8.41	8.56	8.83
Electric Power 7/	6.26	8.41	7.17	7.25	7.27	6.79	6.55	6.26	6.53	6.30	6.28	6.27	6.37	6.59	6.60	6.61	6.66	6.80	7.00	7.18	7.30	7.45	7.62	7.74	7.88	8.02	8.32
Transportation 12/	12.30	14.16	11.29	11.42	11.28	11.51	13.50	13.15	13.44	13.18	13.10	13.07	13.15	13.31	13.32	13.37	13.33	13.45	13.70	13.84	14.00	14.19	14.32	14.50	14.72	14.82	15.11
Average 13/	8.06	9.93	9.41	8.97	8.92	8.43	8.18	7.86	8.04	7.80	7.80	7.78	7.89	8.10	8.11	8.12	8.16	8.27	8.49	8.69	8.84	9.00	9.20	9.36	9.50	9.61	9.85

1/ Marketed production (wet) minus extraction losses.
2/ Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
3/ Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida.
4/ Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
5/ Includes any natural gas used in the process of converting natural gas to liquid fuel that is not actually converted.
6/ Includes any natural gas that is converted into liquid fuel.
7/ Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
8/ Compressed natural gas used as vehicle fuel.
9/ Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
10/ Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2004 and 2005 values include net storage injections.
11/ Represents lower 48 onshore and offshore supplies.
12/ Compressed natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
13/ Weighted average prices. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
Sources: 2004 supply values; and lease, plant, and pipeline fuel consumption: Energy Information Administration (EIA), Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005). 2005 supply values; and lease, plant, and pipeline fuel consumption; and wellhead price: EIA, Natural Gas Monthly, DOE/EIA-0130(2006/04) (Washington, DC, April 2006). Other 2004 and 2005 consumption based on: EIA, Annual Energy Review 2005, DOE/EIA-0384(2005) (Washington, DC, July 2006). 2004 wellhead price: Minerals Management Service and EIA, Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005). 2004 residential and commercial delivered prices: EIA, Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005). 2005 residential and commercial delivered prices: EIA, Natural Gas Monthly, DOE/EIA-0130 (2006/04) (Washington, DC, April 2006). 2004 and 2005 electric power prices: EIA, Electric Power Monthly, DOE/EIA-0226, May 2005 through April 2006, Table 4.11.A. 2004 and 2005 industrial delivered prices are estimated based on: EIA, Manufacturing Energy Consumption Survey 1994 and industrial and wellhead prices from the Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005) and the Natural Gas Monthly, DOE/EIA-0130(2006/04) (Washington, DC, April 2006). 2004 transportation sector delivered prices are based on: EIA, Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005) and estimated state taxes, federal taxes, and dispensing costs or charges. 2005 transportation sector delivered prices are model results. Projections: EIA, AEO2007 National Energy Modeling System run s280comm.d061507a.

HEARING EXHIBIT 20000000

Table 13. Natural Gas Supply, Disposition, and Prices
(trillion cubic feet, unless otherwise noted)

Attachment POD-1.d Table 13 Natural Gas Supply, Disposition, and Prices S.280 High Techonology Case

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Production																											
Dry Gas Production 1/	18.76	18.23	18.58	18.95	19.30	19.23	19.04	19.08	19.11	19.07	19.27	19.29	19.30	19.35	19.93	20.33	20.43	20.57	20.64	20.48	20.49	20.26	20.33	20.23	20.22	20.24	20.08
Supplemental Natural Gas 2/	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Net Imports	3.40	3.57	3.29	3.39	3.81	4.11	4.31	4.65	4.79	5.12	5.00	5.20	5.47	5.42	5.25	4.88	4.94	4.81	4.86	4.91	4.97	5.11	5.10	5.13	5.10	4.98	5.35
Pipeline 3/	2.81	3.01	2.74	2.62	2.70	2.74	2.61	2.44	2.44	2.66	2.54	2.46	2.41	2.22	2.04	1.78	1.54	1.49	1.36	1.24	1.25	1.13	1.02	1.04	1.06	0.96	0.90
Liquefied Natural Gas	0.59	0.57	0.55	0.76	1.11	1.37	1.70	2.21	2.36	2.46	2.46	2.74	3.06	3.19	3.21	3.10	3.40	3.33	3.50	3.66	3.72	3.98	4.08	4.09	4.04	4.02	4.45
Total Supply	22.22	21.87	21.93	22.41	23.18	23.41	23.42	23.80	23.97	24.26	24.35	24.57	24.84	24.84	25.25	25.28	25.44	25.46	25.57	25.45	25.52	25.45	25.50	25.43	25.39	25.29	25.50
Consumption by Sector																											
Residential	4.87	4.84	4.48	4.87	4.95	4.99	5.02	5.05	5.09	5.10	5.11	5.11	5.12	5.10	5.10	5.11	5.13	5.11	5.10	5.10	5.10	5.08	5.07	5.06	5.07	5.05	5.05
Commercial	3.13	3.05	2.92	3.03	3.11	3.17	3.23	3.31	3.38	3.44	3.50	3.55	3.59	3.63	3.67	3.72	3.77	3.82	3.86	3.90	3.95	3.99	4.04	4.09	4.15	4.20	4.27
Industrial 4/	7.22	6.64	6.76	7.09	7.30	7.49	7.47	7.65	7.58	7.69	7.64	7.61	7.63	7.59	7.80	7.66	7.75	7.80	7.96	7.85	7.97	7.95	8.06	8.10	8.06	8.14	8.30
Natural Gas-to-Liquids Heat and Power 5/	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas to Liquids Production 6/	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electric Power 7/	5.51	5.83	5.89	5.76	6.08	6.06	6.00	6.09	6.21	6.32	6.37	6.55	6.75	6.77	6.83	6.87	6.85	6.77	6.69	6.65	6.56	6.49	6.40	6.25	6.19	5.97	5.96
Transportation 8/	0.03	0.03	0.04	0.05	0.05	0.05	0.06	0.06	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.09	0.09	0.09	0.10	0.10	0.10	0.10	0.11	0.11	0.11	0.12	0.12
Pipeline Fuel	0.57	0.56	0.55	0.61	0.62	0.63	0.63	0.64	0.65	0.65	0.66	0.66	0.66	0.67	0.71	0.74	0.75	0.76	0.76	0.76	0.77	0.76	0.76	0.76	0.76	0.76	0.75
Lease and Plant Fuel 9/	1.10	1.07	1.09	1.08	1.07	1.07	1.05	1.05	1.05	1.04	1.05	1.06	1.06	1.06	1.11	1.15	1.16	1.16	1.16	1.15	1.14	1.13	1.12	1.11	1.11	1.11	1.10
Total	22.43	22.02	21.72	22.46	23.19	23.46	23.47	23.85	24.02	24.31	24.40	24.62	24.90	24.89	25.30	25.34	25.49	25.51	25.62	25.51	25.58	25.50	25.55	25.49	25.45	25.35	25.56
Discrepancy 10/	-0.20	-0.15	0.21	-0.05	-0.01	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.06	-0.06	-0.06	-0.06	-0.05
Natural Gas Prices																											
(2005 dollars per million Btu)																											
Henry Hub Spot Price	6.08	8.60	7.07	7.08	7.04	6.46	6.05	5.72	5.46	5.34	5.32	5.31	5.45	5.60	5.59	5.50	5.54	5.60	5.79	5.86	6.03	6.08	6.23	6.30	6.30	6.35	6.29
Average Lower 48 Wellhead Price 11/	5.63	7.29	6.47	6.32	6.28	5.75	5.38	5.08	4.84	4.74	4.72	4.71	4.83	4.97	4.96	4.88	4.92	4.97	5.14	5.21	5.36	5.40	5.54	5.61	5.61	5.65	5.60
(2005 dollars per thousand cubic feet)																											
Average Lower 48 Wellhead Price 11/	5.80	7.51	6.67	6.51	6.47	5.93	5.54	5.23	4.99	4.88	4.86	4.85	4.98	5.12	5.11	5.02	5.07	5.12	5.29	5.36	5.52	5.57	5.71	5.78	5.77	5.82	5.77
Delivered Prices																											
Residential	11.05	12.80	13.43	12.07	11.99	11.47	11.10	10.80	10.56	10.41	10.43	10.42	10.54	10.73	10.72	10.65	10.72	10.77	10.96	11.05	11.19	11.27	11.44	11.54	11.55	11.62	11.59
Commercial	9.69	11.54	11.72	10.44	10.34	9.79	9.40	9.06	8.80	8.63	8.61	8.58	8.68	8.83	8.81	8.72	8.76	8.77	8.93	9.00	9.11	9.15	9.29	9.36	9.34	9.38	9.32
Industrial 4/	6.67	8.41	7.67	7.46	7.37	6.81	6.42	6.08	5.85	5.69	5.70	5.68	5.81	5.96	5.95	5.89	5.93	5.96	6.11	6.20	6.32	6.37	6.49	6.58	6.57	6.61	6.53
Electric Power 7/	6.26	8.41	7.17	7.17	7.11	6.55	6.15	5.84	5.61	5.47	5.47	5.47	5.61	5.77	5.76	5.67	5.73	5.75	5.91	5.98	6.09	6.13	6.27	6.33	6.31	6.32	6.25
Transportation 12/	12.30	14.16	11.29	11.36	11.19	11.38	13.22	12.82	12.54	12.32	12.27	12.23	12.31	12.41	12.37	12.29	12.29	12.27	12.44	12.43	12.52	12.58	12.66	12.73	12.77	12.78	12.75
Average 13/	8.06	9.93	9.41	8.90	8.80	8.25	7.89	7.56	7.32	7.16	7.17	7.15	7.26	7.43	7.40	7.34	7.39	7.42	7.59	7.68	7.80	7.86	8.00	8.09	8.09	8.15	8.08

1/ Marketed production (wet) minus extraction losses.
2/ Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
3/ Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida.
4/ Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
5/ Includes any natural gas used in the process of converting natural gas to liquid fuel that is not actually converted.
6/ Includes any natural gas that is converted into liquid fuel.
7/ Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
8/ Compressed natural gas used as vehicle fuel.
9/ Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
10/ Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2004 and 2005 values include net storage injections.
11/ Represents lower 48 onshore and offshore supplies.
12/ Compressed natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
13/ Weighted average prices. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
Sources: 2004 supply values; and lease, plant, and pipeline fuel consumption: Energy Information Administration (EIA), Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005). 2005 supply values; and lease, plant, and pipeline fuel consumption; and wellhead price: EIA, Natural Gas Monthly, DOE/EIA-0130(2006/04) (Washington, DC, April 2006). Other 2004 and 2005 consumption based on: EIA, Annual Energy Review 2005, DOE/EIA-0384(2005) (Washington, DC, July 2006). 2004 wellhead price: Minerals Management Service and EIA, Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005). 2004 residential and commercial delivered prices: EIA, Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005). 2005 residential and commercial delivered prices: EIA, Natural Gas Monthly, DOE/EIA-0130 (2006/04) (Washington, DC, April 2006). 2004 and 2005 electric power prices: EIA, Electric Power Monthly, DOE/EIA-0226, May 2005 through April 2006, Table 4.11.A. 2004 and 2005 industrial delivered prices are estimated based on: EIA, Manufacturing Energy Consumption Survey 1994 and industrial and wellhead prices from the Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005) and the Natural Gas Monthly, DOE/EIA-0130(2006/04) (Washington, DC, April 2006). 2004 transportation sector delivered prices are based on: EIA, Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005) and estimated state taxes, federal taxes, and dispensing costs or charges. 2005 transportation sector delivered prices are model results. Projections: EIA, AEO2007 National Energy Modeling System run htrkiten d060107a.

HEARING EXHIBIT - 00000169

Table 11. Natural Gas Supply, Disposition, and Prices
(trillion cubic feet, unless otherwise noted)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Production																											
Dry Gas Production 1/	18.76	18.23	18.58	19.03	19.50	19.54	19.51	19.63	19.39	19.31	19.85	19.67	19.67	19.75	20.23	20.81	20.85	21.03	21.15	21.10	20.97	20.51	20.74	20.71	20.68	20.86	20.82
Supplemental Natural Gas 2/	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Net Imports	3.40	3.57	3.29	3.38	3.87	4.32	4.69	5.11	5.13	5.42	5.48	5.79	5.95	5.81	5.53	5.28	5.41	5.28	5.24	5.34	5.36	5.54	5.76	5.76	5.87	5.95	6.16
Pipeline 3/	2.81	3.01	2.74	2.62	2.76	2.87	2.82	2.93	2.92	2.92	2.83	2.74	2.65	2.42	2.20	1.95	1.69	1.61	1.47	1.36	1.36	1.32	1.32	1.23	1.17	1.08	1.04
Liquefied Natural Gas	0.59	0.57	0.55	0.76	1.11	1.45	1.87	2.40	2.39	2.51	2.65	3.05	3.27	3.39	3.34	3.33	3.72	3.68	3.77	3.98	4.00	4.22	4.44	4.53	4.69	4.86	5.13
Total Supply	22.22	21.87	21.93	22.49	23.44	23.94	24.27	24.81	24.57	24.81	25.39	25.51	25.66	25.64	25.83	26.16	26.33	26.38	26.46	26.51	26.39	26.12	26.57	26.55	26.62	26.88	27.06
Consumption by Sector																											
Residential	4.87	4.84	4.48	4.89	4.96	5.00	5.03	5.06	5.11	5.13	5.14	5.15	5.17	5.16	5.17	5.18	5.20	5.19	5.19	5.18	5.19	5.18	5.18	5.17	5.18	5.16	5.15
Commercial	3.13	3.05	2.92	3.02	3.10	3.16	3.21	3.27	3.35	3.42	3.47	3.51	3.56	3.59	3.64	3.68	3.73	3.78	3.82	3.86	3.91	3.97	4.03	4.09	4.17	4.24	4.32
Industrial 4/	7.22	6.64	6.76	7.03	7.33	7.56	7.64	7.74	7.67	7.68	7.62	7.66	7.73	7.72	7.75	7.86	7.95	8.01	8.04	8.13	8.14	8.30	8.49	8.60	8.52	8.84	8.82
Natural Gas to-Liquids Heat and P	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas to Liquids Production	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electric Power 7/	5.51	5.83	5.90	5.87	6.33	6.49	6.66	6.99	6.71	6.85	7.18	7.41	7.41	7.36	7.39	7.46	7.46	7.39	7.19	7.32	7.15	6.71	6.89	6.71	6.78	6.66	6.78
Transportation 8/	0.03	0.03	0.04	0.05	0.05	0.05	0.06	0.06	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.09	0.09	0.09	0.10	0.10	0.10	0.11	0.11	0.11	0.12	0.12	0.12
Pipeline Fuel	0.57	0.56	0.55	0.61	0.63	0.64	0.65	0.66	0.67	0.67	0.69	0.69	0.69	0.70	0.73	0.73	0.78	0.79	0.80	0.80	0.79	0.78	0.79	0.79	0.79	0.79	0.79
Lease and Plant Fuel 9/	1.10	1.07	1.09	1.06	1.08	1.08	1.07	1.07	1.06	1.05	1.08	1.08	1.08	1.06	1.12	1.17	1.17	1.18	1.18	1.17	1.14	1.14	1.14	1.14	1.13	1.13	1.13
Total	22.43	22.02	21.73	22.54	23.49	23.98	24.32	24.86	24.62	24.86	25.44	25.58	25.71	25.69	25.88	26.21	26.39	26.44	26.51	26.56	26.45	26.18	26.62	26.61	26.68	26.94	27.12
Discrepancy 10/	-0.20	-0.15	0.20	-0.05	-0.05	-0.04	0.05	-0.05	0.05	-0.05	-0.05	0.05	0.05	0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.06	-0.06	-0.06	-0.06	-0.06	-0.06	-0.06	-0.06
Natural Gas Prices																											
(2005 dollars per million Btu)																											
Henry Hub Spot Price	6.08	8.60	7.07	7.15	7.22	6.73	6.42	6.11	5.65	5.44	5.60	5.50	5.58	5.76	5.69	5.69	5.72	5.74	5.94	6.12	6.24	6.08	6.33	6.48	6.51	6.70	6.73
Average Lower 48 Wellhead Price	5.63	7.29	6.47	6.38	6.45	6.00	5.72	5.43	5.02	4.83	4.97	4.88	4.95	5.11	5.05	5.05	5.08	5.10	5.28	5.45	5.55	5.41	5.64	5.77	5.80	5.97	6.00
(2005 dollars per thousand cubic feet)																											
Average Lower 48 Wellhead Price	5.80	7.51	6.67	6.58	6.64	6.18	5.89	5.60	5.17	4.97	5.12	5.02	5.10	5.27	5.20	5.21	5.23	5.25	5.44	5.61	5.71	5.57	5.81	5.94	5.98	6.15	6.18
Delivered Prices																											
Residential	11.05	12.80	13.43	12.10	12.14	11.71	11.43	11.17	10.76	10.53	10.68	10.60	10.66	10.85	10.79	10.82	10.85	10.86	11.07	11.26	11.35	11.25	11.50	11.68	11.73	11.93	11.98
Commercial	9.69	11.54	11.72	10.49	10.51	10.04	9.75	9.45	9.02	8.77	8.90	8.79	8.84	9.00	8.92	8.93	8.94	8.92	9.10	9.25	9.32	9.17	9.40	9.54	9.56	9.72	9.74
Industrial 4/	6.67	8.41	7.67	7.51	7.55	7.06	6.76	6.46	6.80	6.61	6.82	6.78	6.92	7.17	7.20	7.31	7.43	7.52	7.82	8.10	8.31	8.30	8.68	8.98	9.21	9.56	9.80
Electric Power 7/	6.26	8.41	7.17	7.24	7.32	6.84	6.56	6.31	6.58	6.37	6.64	6.59	6.72	6.97	7.00	7.11	7.23	7.32	7.64	7.90	8.11	8.05	8.45	8.73	8.95	9.33	9.57
Transportation 12/	12.30	14.16	11.29	11.40	11.33	11.56	13.52	13.19	13.49	13.25	13.37	13.32	13.41	13.59	13.59	13.71	13.77	13.84	14.13	14.34	14.52	14.57	14.88	15.17	15.43	15.73	15.99
Average 13/	8.06	9.93	9.41	8.95	8.96	8.48	8.18	7.89	7.97	7.75	7.93	7.87	7.97	8.20	8.19	8.27	8.35	8.41	8.68	8.92	9.09	9.03	9.36	9.60	9.76	10.05	10.21

1/ Marketed production (wet) minus extraction losses.
2/ Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
3/ Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida.
4/ Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
5/ Includes any natural gas used in the process of converting natural gas to liquid fuel that is not actually converted..
6/ Includes any natural gas that is converted into liquid fuel.
7/ Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
8/ Compressed natural gas used as vehicle fuel.
9/ Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
10/ Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2004 and 2005 values include net storage injections.
11/ Represents lower 48 onshore and offshore supplies.
12/ Compressed natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
13/ Weighted average prices. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
Sources: 2004 supply values; and lease, plant, and pipeline fuel consumption: Energy Information Administration (EIA), Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005). 2005 supply values; and lease, plant, and pipeline fuel consumption; and wellhead price: EIA, Natural Gas Monthly, DOE/EIA-0130(2006/04) (Washington, DC, April 2006). Other 2004 and 2005 consumption based on: EIA, Annual Energy Review 2005, DOE/EIA-0384(2005) (Washington, DC, July 2006). 2004 wellhead price: Minerals Management Service and EIA, Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005). 2004 residential and commercial delivered prices: EIA, Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005). 2005 residential and commercial delivered prices: EIA, Natural Gas Monthly, DOE/EIA-0130 (2006/04) (Washington, DC, April 2006). 2004 and 2005 electric power prices: EIA, Electric Power Monthly, DOE/EIA-0226, May 2005 through April 2006, Table 4.11.A. 2004 and 2005 industrial delivered prices are estimated based on: EIA, Manufacturing Energy Consumption Survey 1994 and industrial and wellhead prices from the Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005) and the Natural Gas Monthly, DOE/EIA-0130(2006/04) (Washington, DC, April 2006). 2004 transportation sector delivered prices are based on: EIA, Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005) and estimated state taxes, federal taxes, and dispensing costs or charges. 2005 transportation sector delivered prices are model results. Projections: EIA, AEO2007 National Energy Modeling System run s280nucbio.d092807a.

HEARING EXHIBIT

Table 13 Natural Gas Supply, Disposition, and Prices
(trillion cubic feet, unless otherwise noted)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Production																											
Dry Gas Production 1/	18.76	18.23	18.58	19.01	19.46	19.50	19.51	19.53	19.39	19.30	19.57	20.11	19.81	19.93	20.49	21.05	20.97	21.26	21.33	21.39	21.37	21.14	21.20	21.29	21.36	21.53	21.61
Supplemental Natural Gas 2/	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Net Imports	3.40	3.57	3.29	3.40	3.88	4.30	4.68	5.09	5.06	5.39	5.26	5.93	6.13	6.04	5.84	5.56	5.73	5.71	5.67	5.54	5.69	6.36	6.48	6.65	6.72	6.76	7.74
Pipeline 3/	2.81	3.01	2.74	2.63	2.76	2.86	2.81	2.71	2.68	2.67	2.74	2.75	2.70	2.49	2.29	2.05	1.78	1.70	1.57	1.45	1.47	1.50	1.53	1.44	1.40	1.33	1.45
Liquefied Natural Gas	0.59	0.57	0.55	0.76	1.11	1.44	1.87	2.39	2.38	2.52	2.52	3.17	3.44	3.54	3.55	3.52	3.95	4.01	4.10	4.09	4.22	4.85	4.95	5.20	5.32	5.43	6.29
Total Supply	22.22	21.87	21.93	22.48	23.41	23.87	24.26	24.70	24.52	24.76	24.91	26.11	26.02	26.04	26.40	26.68	26.78	27.05	27.07	27.01	27.13	27.56	27.75	28.00	28.15	28.37	29.42
Consumption by Sector																											
Residential	4.87	4.84	4.48	4.89	4.97	5.00	5.03	5.06	5.11	5.13	5.15	5.15	5.16	5.15	5.15	5.16	5.19	5.18	5.18	5.17	5.17	5.15	5.15	5.14	5.15	5.12	5.12
Commercial	3.13	3.05	2.92	3.03	3.10	3.16	3.21	3.28	3.35	3.42	3.48	3.51	3.54	3.58	3.62	3.66	3.71	3.76	3.81	3.85	3.89	3.95	4.01	4.07	4.14	4.21	4.30
Industrial 4/	7.22	6.64	6.76	7.03	7.29	7.46	7.62	7.58	7.62	7.74	7.67	7.72	7.69	7.81	7.86	7.95	7.87	7.99	8.05	8.07	8.09	8.11	8.22	8.44	8.38	8.43	8.60
Natural Gas-to-Liquids Heat and Power 5/	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas to Liquids Production 6/	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electric Power 7/	5.51	5.83	5.90	5.86	6.34	6.53	6.68	7.03	6.70	6.74	6.85	7.91	7.82	7.70	7.87	7.91	8.00	8.07	7.99	7.88	7.95	8.32	8.35	8.32	8.45	8.55	9.35
Transportation 8/	0.03	0.03	0.04	0.05	0.05	0.05	0.06	0.06	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.09	0.09	0.09	0.10	0.10	0.10	0.11	0.11	0.11	0.11	0.12	0.12
Pipeline Fuel	0.57	0.56	0.55	0.61	0.63	0.64	0.65	0.66	0.67	0.67	0.68	0.70	0.70	0.70	0.74	0.78	0.79	0.81	0.81	0.81	0.81	0.82	0.82	0.82	0.82	0.83	0.83
Lease and Plant Fuel 9/	1.10	1.07	1.09	1.06	1.08	1.08	1.07	1.07	1.06	1.05	1.07	1.09	1.08	1.09	1.13	1.18	1.18	1.19	1.19	1.19	1.18	1.16	1.16	1.16	1.16	1.16	1.16
Total	22.43	22.02	21.74	22.53	23.46	23.92	24.31	24.75	24.57	24.81	24.96	26.16	26.07	26.09	26.45	26.74	26.83	27.10	27.12	27.06	27.19	27.62	27.81	28.06	28.21	28.42	29.48
Discrepancy 10/	-0.20	-0.15	0.20	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	0.05	0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.06	-0.06	-0.06	-0.06	-0.06	-0.06	-0.06	-0.06
Natural Gas Prices																											
(2005 dollars per million Btu)																											
Henry Hub Spot Price	6.08	8.60	7.07	7.13	7.19	6.69	6.43	6.07	5.65	5.45	5.43	5.74	5.75	5.89	5.88	5.87	5.79	5.86	6.05	6.29	6.51	6.51	6.67	6.84	6.98	7.13	7.17
Average Lower 48 Wellhead Price 11/	5.63	7.29	6.47	6.37	6.42	5.96	5.72	5.40	5.01	4.83	4.82	5.10	5.11	5.24	5.22	5.21	5.14	5.21	5.38	5.60	5.80	5.80	5.94	6.10	6.22	6.37	6.40
(2005 dollars per thousand cubic feet)																											
Average Lower 48 Wellhead Price 11/	5.80	7.51	6.67	6.56	6.61	6.14	5.89	5.56	5.16	4.98	4.96	5.25	5.26	5.39	5.38	5.37	5.30	5.36	5.54	5.77	5.97	5.97	6.12	6.29	6.41	6.56	6.59
Delivered Prices																											
Residential	11.05	12.80	13.43	12.09	12.11	11.67	11.43	11.13	10.74	10.51	10.53	10.80	10.80	10.98	10.98	10.98	10.94	10.99	11.19	11.42	11.59	11.66	11.83	12.02	12.17	12.35	12.39
Commercial	9.69	11.54	11.72	10.48	10.48	10.01	9.75	9.41	9.00	8.76	8.75	9.00	8.99	9.13	9.11	9.09	9.02	9.04	9.21	9.41	9.57	9.59	9.73	9.88	10.01	10.14	10.15
Industrial 4/	6.67	8.41	7.67	7.50	7.53	7.04	6.77	6.44	6.86	6.70	6.78	7.15	7.23	7.44	7.54	7.65	7.71	7.86	8.17	8.52	8.85	9.03	9.36	9.69	10.05	10.41	10.67
Electric Power 7/	6.26	8.41	7.17	7.22	7.29	6.81	6.56	6.28	6.63	6.46	6.54	7.03	7.08	7.30	7.42	7.53	7.58	7.75	8.04	8.38	8.73	8.97	9.29	9.63	9.99	10.37	10.74
Transportation 12/	12.30	14.16	11.29	11.39	11.30	11.53	13.51	13.16	13.54	13.34	13.33	13.68	13.71	13.88	13.94	14.04	14.03	14.18	14.46	14.74	15.03	15.23	15.49	15.82	16.16	16.48	16.76
Average 13/	8.06	9.93	9.41	8.94	8.94	8.45	8.19	7.86	7.99	7.80	7.86	8.17	8.22	8.42	8.48	8.54	8.56	8.68	8.94	9.24	9.52	9.66	9.91	10.19	10.47	10.76	10.96

1/ Marketed production (wet) minus extraction losses.
2/ Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas
3/ Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida.
4/ Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
5/ Includes any natural gas used in the process of converting natural gas to liquid fuel that is not actually converted.
6/ Includes any natural gas that is converted into liquid fuel.
7/ Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
8/ Compressed natural gas used as vehicle fuel.
9/ Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
10/ Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2004 and 2005 values include net storage injections.
11/ Represents lower 48 onshore and offshore supplies.
12/ Compressed natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
13/ Weighted average prices. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
Sources: 2004 supply values; and lease, plant, and pipeline fuel consumption: Energy Information Administration (EIA), Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005). 2005 supply values; and lease, plant, and pipeline fuel consumption; and wellhead price: EIA, Natural Gas Monthly, DOE/EIA-0130(2006/04) (Washington, DC, April 2006). Other 2004 and 2005 consumption based on: EIA, Annual Energy Review 2005, DOE/EIA-0384(2005) (Washington, DC, July 2006). 2004 wellhead price: Minerals Management Service and EIA, Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005). 2004 residential and commercial delivered prices: EIA, Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005). 2005 residential and commercial delivered prices: EIA, Natural Gas Monthly, DOE/EIA-0130 (2006/04) (Washington, DC, April 2006). 2004 and 2005 electric power prices: EIA, Electric Power Monthly, DOE/EIA-0226, May 2005 through April 2006, Table 4.11.A. 2004 and 2005 industrial delivered prices are estimated based on: EIA, Manufacturing Energy Consumption Survey 1994 and industrial and wellhead prices from the Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005) and the Natural Gas Monthly, DOE/EIA-0130(2006/04) (Washington, DC, April 2006). 2004 transportation sector delivered prices are based on: EIA, Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005) and estimated state taxes, federal taxes, and dispensing costs or charges. 2005 transportation sector delivered prices are model results. Projections: EIA, AEO2007 National Energy Modeling System run s280ccs.d092807a.

HEARING EXHIBIT - 00000171

Table 13. Natural Gas Supply, Disposition, and Prices
(trillion cubic feet, unless otherwise noted)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Production																											
Dry Gas Production 1/	18.76	18.23	18.58	19.04	19.45	19.48	19.58	19.64	19.44	19.27	20.12	19.90	19.89	19.99	20.49	21.06	21.05	21.51	21.47	21.54	21.54	21.39	21.53	21.60	21.67	21.84	22.17
Supplemental Natural Gas 2/	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Net Imports	3.40	3.57	3.29	3.41	3.88	4.26	4.61	5.00	5.09	5.42	5.45	5.79	5.97	5.88	5.59	5.29	5.48	5.37	5.29	5.34	5.54	6.10	6.02	6.00	6.11	6.07	6.10
Pipeline 3/	2.81	3.01	2.74	2.65	2.77	2.84	2.80	2.74	2.71	2.89	2.86	2.80	2.73	2.51	2.29	2.04	1.79	1.75	1.63	1.54	1.69	1.72	1.64	1.59	1.58	1.53	1.56
Liquefied Natural Gas	0.59	0.57	0.55	0.76	1.11	1.42	1.81	2.26	2.38	2.53	2.59	2.99	3.23	3.37	3.30	3.25	3.69	3.62	3.65	3.80	3.85	4.38	4.37	4.41	4.53	4.54	4.53
Total Supply	22.22	21.87	21.94	22.52	23.41	23.81	24.26	24.71	24.61	24.76	25.64	25.77	25.93	25.94	26.16	26.42	26.60	26.95	26.83	26.95	27.15	27.57	27.62	27.67	27.85	27.99	28.34
Consumption by Sector																											
Residential	4.87	4.84	4.48	4.89	4.97	5.00	5.03	5.06	5.11	5.13	5.13	5.14	5.16	5.15	5.15	5.17	5.19	5.17	5.17	5.16	5.16	5.14	5.14	5.13	5.13	5.11	5.10
Commercial	3.13	3.05	2.92	3.02	3.10	3.16	3.21	3.27	3.34	3.42	3.46	3.50	3.54	3.58	3.62	3.66	3.71	3.76	3.80	3.84	3.88	3.94	3.99	4.05	4.12	4.19	4.27
Industrial 4/	7.22	6.64	6.76	7.08	7.29	7.39	7.58	7.58	7.75	7.67	7.63	7.69	7.74	7.80	7.80	7.91	7.90	8.15	7.95	8.03	8.09	8.20	8.23	8.25	8.31	8.31	8.34
Natural Gas-to-Liquids Heat and Power 5/	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas to Liquids Production 6/	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electric Power 7/	5.51	5.83	5.90	5.86	6.33	6.54	6.71	7.05	6.67	6.81	7.62	7.63	7.68	7.60	7.68	7.69	7.79	7.82	7.86	7.88	7.97	8.25	8.22	8.20	8.25	8.32	8.55
Transportation 8/	0.03	0.03	0.04	0.05	0.05	0.05	0.06	0.06	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.09	0.09	0.09	0.10	0.10	0.10	0.10	0.11	0.11	0.11	0.11	0.12
Pipeline Fuel	0.57	0.56	0.55	0.62	0.63	0.64	0.65	0.66	0.67	0.67	0.70	0.70	0.70	0.70	0.74	0.78	0.79	0.81	0.81	0.81	0.82	0.82	0.82	0.82	0.82	0.83	0.83
Lease and Plant Fuel 9/	1.10	1.07	1.09	1.06	1.08	1.08	1.08	1.07	1.08	1.05	1.09	1.09	1.09	1.09	1.13	1.18	1.18	1.20	1.20	1.19	1.19	1.17	1.18	1.17	1.17	1.18	1.19
Total	22.43	22.02	21.74	22.57	23.46	23.86	24.31	24.77	24.66	24.81	25.69	25.82	25.98	25.99	26.21	26.47	26.66	27.01	26.88	27.00	27.20	27.63	27.67	27.73	27.91	28.04	28.40
Discrepancy 10/	-0.20	-0.15	0.20	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.06	-0.06	-0.06	-0.06	-0.06	-0.06	-0.06	-0.06
Natural Gas Prices																											
(2005 dollars per million Btu)																											
Henry Hub Spot Price	6.08	8.60	7.07	7.16	7.19	6.67	6.47	6.16	5.70	5.42	5.77	5.68	5.73	5.89	5.84	5.83	5.81	6.02	6.17	6.38	6.60	6.65	6.89	7.07	7.15	7.29	7.55
Average Lower 48 Wellhead Price 11/	5.63	7.29	6.47	6.39	6.42	5.95	5.76	5.48	5.06	4.81	5.13	5.04	5.09	5.24	5.19	5.18	5.16	5.35	5.49	5.68	5.88	5.93	6.14	6.30	6.38	6.51	6.75
(2005 dollars per thousand cubic feet)																											
Average Lower 48 Wellhead Price 11/	5.80	7.51	6.67	6.58	6.61	6.12	5.93	5.64	5.21	4.95	5.28	5.19	5.24	5.39	5.34	5.34	5.32	5.51	5.65	5.85	6.06	6.10	6.33	6.49	6.58	6.70	6.95
Delivered Prices																											
Residential	11.05	12.80	13.43	12.12	12.11	11.65	11.46	11.21	10.78	10.50	10.82	10.75	10.79	10.98	10.94	10.94	10.96	11.14	11.29	11.52	11.71	11.80	12.05	12.25	12.36	12.52	12.79
Commercial	9.69	11.54	11.72	10.51	10.48	9.98	9.78	9.50	9.05	8.74	9.08	8.96	8.97	9.13	9.07	9.08	9.04	9.19	9.32	9.51	9.68	9.73	9.95	10.11	10.19	10.30	10.54
Industrial 4/	6.67	8.41	7.67	7.53	7.53	7.02	6.80	6.52	6.90	6.70	7.13	7.11	7.22	7.45	7.53	7.62	7.74	8.02	8.30	8.64	8.98	9.20	9.60	9.96	10.25	10.60	11.10
Electric Power 7/	6.26	8.41	7.17	7.25	7.28	6.79	6.61	6.36	6.68	6.45	6.98	6.95	7.06	7.31	7.39	7.49	7.61	7.91	8.18	8.52	8.86	9.11	9.52	9.87	10.17	10.53	11.07
Transportation 12/	12.30	14.16	11.29	11.41	11.30	11.51	13.55	13.22	13.59	13.34	13.66	13.62	13.70	13.88	13.91	14.02	14.06	14.33	14.58	14.86	15.16	15.37	15.71	16.05	16.34	16.65	17.12
Average 13/	8.06	9.93	9.41	8.97	8.94	8.43	8.22	7.95	8.04	7.80	8.17	8.13	8.21	8.43	8.46	8.52	8.60	8.83	9.07	9.36	9.64	9.80	10.15	10.44	10.66	10.94	11.35

1/ Marketed production (wet) minus extraction losses.
2/ Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
3/ Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida.
4/ Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
5/ Includes any natural gas used in the process of converting natural gas to liquid fuel that is not actually converted.
6/ Includes any natural gas that is converted into liquid fuel.
7/ Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
8/ Compressed natural gas used as vehicle fuel.
9/ Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
10/ Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2004 and 2005 values include net storage injections.
11/ Represents lower 48 onshore and offshore supplies.
12/ Compressed natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
13/ Weighted average prices. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
Sources: 2004 supply values; and lease, plant, and pipeline fuel consumption: Energy Information Administration (EIA), Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005). 2005 supply values; and lease, plant, and pipeline fuel consumption; and wellhead price: EIA, Natural Gas Monthly, DOE/EIA-0130(2006/04) (Washington, DC, April 2006). Other 2004 and 2005 consumption based on: EIA, Annual Energy Review 2005, DOE/EIA-0384(2005) (Washington, DC, July 2006). 2004 wellhead price: Minerals Management Service and EIA, Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005). 2004 residential and commercial delivered prices: EIA, Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005). 2005 residential and commercial delivered prices: EIA, Natural Gas Monthly, DOE/EIA-0130 (2006/04) (Washington, DC, April 2006). 2004 and 2005 electric power prices: EIA, Electric Power Monthly, DOE/EIA-0226, May 2005 through April 2006, Table 4.11.A. 2004 and 2005 industrial delivered prices are estimated based on: EIA, Manufacturing Energy Consumption Survey 1994 and industrial and wellhead prices from the Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005) and the Natural Gas Monthly, DOE/EIA-0130(2006/04) (Washington, DC, April 2006). 2004 transportation sector delivered prices are based on: EIA, Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005) and estimated state taxes, federal taxes, and dispensing costs or

HEARING EXHIBIT - 00000176

Attachment POD-1.cf. Table 12 Petroleum Product Prices

Cases:

Reference
Core S.280
No International S.280
Fixed 30% Offset S.280
No Nuclear S.280
Low Discount S.280
Unlimited Offset S.280
High Auction S.280
Commercial Covered S.280
High Technology S.280
Ref NB S.280
Ref NB+noCCS S.280
Ref NBLNG+noCCS S.280

HEARING EXHIBIT - 00000173

Table 12 Petroleum Product Prices
(2005 cents per gallon, unless otherwise noted)

Attachment POD-1 of AEO2007 Table 12 Petroleum Product Prices Reference Case

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2005-2030
Crude Oil Prices (2005 dollars per barrel)																												
Imported Low-Sulfur Light Crude Oil 1/	42.87	56.76	69.11	66.71	64.09	60.91	57.47	54.33	51.71	49.99	49.64	49.87	49.75	50.80	51.28	51.95	52.04	52.73	53.43	54.90	55.64	56.37	57.11	57.63	58.12	58.61	59.12	0.2%
Imported Crude Oil 1/	37.09	49.19	61.75	59.49	57.23	54.21	51.20	48.48	46.22	45.01	44.41	44.61	44.81	45.22	45.64	46.05	46.47	47.08	47.71	48.33	48.94	49.57	49.97	50.40	50.80	51.21	51.63	0.2%
Delivered Sector Product Prices																												
Residential																												
Liquefied Petroleum Gases	156.9	166.3	182.3	211.5	211.1	206.5	204.0	200.5	199.1	197.4	197.7	197.2	198.0	199.9	199.3	199.0	199.8	199.5	200.7	201.8	202.9	202.8	203.1	203.8	205.0	205.7	206.1	0.9%
Distillate Fuel Oil	178.8	204.3	234.5	242.0	234.5	219.6	206.3	194.6	185.3	174.7	173.7	174.7	175.2	176.7	177.9	181.0	182.3	183.9	186.2	185.3	187.4	188.1	189.0	191.4	192.8	195.0	195.9	-0.2%
Commercial																												
Distillate Fuel Oil	145.0	175.4	202.3	211.7	199.3	185.7	175.5	165.2	156.3	149.5	147.1	147.9	149.9	150.6	152.0	155.7	156.5	158.0	161.1	158.7	161.1	163.4	163.5	166.2	168.9	169.9	171.7	-0.1%
Residual Fuel Oil	93.5	126.0	151.2	118.0	116.7	114.9	112.8	105.7	103.6	89.7	94.5	97.2	96.5	98.6	100.3	104.6	105.8	108.4	110.8	108.3	110.4	107.3	109.3	110.7	111.7	108.4	109.4	-0.6%
Residual Fuel Oil (2005 dollars per barrel)	39.29	52.90	63.50	49.55	49.03	48.28	47.39	44.39	43.50	37.66	39.69	40.83	40.54	41.40	42.13	43.94	44.44	45.53	46.53	45.49	46.38	45.08	45.89	46.49	46.92	45.51	45.97	-0.6%
Industrial 2/																												
Liquefied Petroleum Gases	96.3	146.2	163.4	150.9	149.9	144.4	141.5	137.4	135.9	134.6	134.7	134.1	135.2	136.7	136.7	136.7	137.1	136.9	137.8	138.8	140.1	139.8	139.9	140.6	141.5	142.3	142.6	-0.1%
Distillate Fuel Oil	152.2	181.1	209.6	213.1	196.9	184.9	178.1	171.3	163.1	159.8	155.8	156.5	159.7	159.7	161.1	165.6	165.3	166.6	170.5	167.1	169.7	173.2	172.7	175.6	179.4	179.3	181.8	0.0%
Residual Fuel Oil	86.4	116.3	139.8	147.8	151.0	146.6	142.2	131.4	126.8	120.3	119.4	122.9	125.9	128.1	128.9	131.9	133.4	135.7	137.8	137.0	139.1	138.6	140.5	142.3	142.2	143.8	143.5	0.8%
Residual Fuel Oil (2005 dollars per barrel)	36.30	48.86	58.73	62.09	63.40	61.55	59.74	55.19	53.24	50.53	50.15	51.64	52.88	53.80	54.13	55.38	56.04	57.00	57.89	57.52	58.41	58.21	59.00	59.75	59.71	60.40	60.25	0.8%
Transportation																												
Liquefied Petroleum Gases	169.5	206.1	231.0	195.7	196.1	191.9	209.8	206.3	204.8	202.8	203.1	202.4	203.0	204.7	203.9	203.2	203.9	203.6	204.6	205.7	206.6	206.4	206.6	207.3	208.3	209.1	209.3	0.1%
Ethanol (E85) 3/	196.5	217.1	233.1	260.0	243.0	226.4	198.5	191.4	189.6	188.3	186.5	187.3	188.3	190.5	190.2	192.3	192.1	192.2	196.4	195.5	195.4	198.2	196.7	198.7	199.8	199.5	200.4	-0.3%
Ethanol Wholesale Price	177.2	180.4	248.0	252.0	206.6	209.9	181.4	174.2	171.3	166.1	165.1	166.0	166.6	168.6	167.5	168.7	168.2	167.5	171.3	170.2	169.0	171.1	169.5	171.3	171.2	170.5	170.2	-0.2%
Motor Gasoline 4/	195.2	231.6	262.7	257.5	241.3	227.3	217.3	209.2	204.7	201.1	195.2	194.9	195.5	197.1	198.1	202.3	201.9	203.3	206.9	205.3	207.5	210.2	208.0	209.8	212.7	212.6	215.4	-0.3%
Jet Fuel 5/	124.4	177.4	201.9	175.4	158.3	152.0	147.2	140.0	135.8	135.5	132.9	133.5	135.4	136.2	137.8	142.1	141.8	142.9	147.1	145.6	147.3	149.8	149.2	151.6	155.5	155.4	158.6	-0.4%
Diesel Fuel (distillate fuel oil) 6/	187.1	241.3	272.0	270.4	249.9	237.5	230.4	219.3	210.9	208.5	203.1	203.6	207.2	206.6	207.7	212.1	211.2	212.2	216.1	212.0	214.3	218.1	217.0	219.6	223.8	222.8	225.7	-0.3%
Residual Fuel Oil	72.7	82.4	107.2	132.1	135.4	128.8	120.5	115.1	109.9	106.3	104.4	105.4	105.3	106.6	106.9	107.3	110.2	112.1	114.5	114.9	117.5	118.2	120.3	122.5	121.5	125.4	123.8	1.6%
Residual Fuel Oil (2005 dollars per barrel)	30.51	34.62	45.03	55.46	56.89	54.09	50.60	48.35	46.17	44.65	43.84	44.27	44.21	44.78	44.91	45.07	46.27	47.08	48.08	48.26	49.36	49.65	50.53	51.45	51.05	52.69	52.02	1.6%
Electric Power 7/																												
Distillate Fuel Oil	132.0	157.9	183.6	197.8	191.0	176.2	162.3	149.5	139.1	128.8	127.6	128.4	128.7	130.9	132.2	135.2	136.5	138.1	140.2	139.8	141.7	142.2	143.1	145.4	146.6	149.0	149.6	-0.2%
Residual Fuel Oil	74.7	104.2	117.4	107.7	109.2	104.7	98.5	92.9	88.4	81.7	81.6	83.8	84.3	85.9	87.0	89.9	91.0	93.3	96.1	94.6	97.8	98.5	99.3	100.8	101.0	102.5	102.5	-0.1%
Residual Fuel Oil (2005 dollars per barrel)	31.38	43.76	49.33	45.23	45.86	43.96	41.37	39.02	37.11	34.31	34.29	35.20	35.39	36.07	36.55	37.77	38.24	39.17	40.35	39.73	41.08	41.37	41.73	42.34	42.42	43.06	43.05	-0.1%
Refined Petroleum Product Prices 8/																												
Liquefied Petroleum Gases	109.3	150.7	167.7	163.7	162.7	157.6	155.3	151.4	150.1	148.8	149.0	148.6	149.7	151.4	151.4	151.3	151.9	151.7	152.7	153.8	155.0	154.8	155.0	155.8	156.7	157.4	157.7	0.2%
Motor Gasoline 4/	195.0	231.1	262.1	257.4	241.3	227.3	217.3	209.2	204.7	201.1	195.2	194.9	195.5	197.1	198.1	202.3	201.8	203.3	206.9	205.3	207.5	210.2	208.0	209.8	212.7	212.6	215.4	-0.3%
Jet Fuel 5/	124.4	177.4	201.9	175.4	158.3	152.0	147.2	140.0	135.8	135.5	132.9	133.5	135.4	136.2	137.8	142.1	141.8	142.9	147.1	145.6	147.3	149.8	149.2	151.6	155.5	155.4	158.6	-0.4%
Distillate Fuel Oil	178.3	223.9	254.0	253.8	236.6	224.1	215.9	205.0	197.2	194.7	190.3	191.0	194.3	194.2	195.5	199.8	199.4	200.7	204.5	201.0	203.5	207.0	206.3	209.1	213.1	212.7	215.5	-0.2%
Residual Fuel Oil	76.3	98.6	118.5	123.5	125.8	120.6	113.9	107.7	102.8	96.6	95.9	98.0	98.3	100.0	100.8	102.8	104.7	106.9	109.4	108.8	111.5	111.9	113.5	115.3	114.9	117.2	116.6	0.7%
Residual Fuel Oil (2005 dollars per barrel)	32.05	41.42	49.78	51.89	52.84	50.66	47.84	45.23	43.18	40.58	40.28	41.16	41.30	42.01	42.36	43.16	43.98	44.89	45.95	45.69	46.84	46.99	47.66	48.42	48.26	49.24	48.96	0.7%
Average	168.6	204.5	232.6	228.3	213.7	203.2	195.0	187.0	182.2	179.5	175.5	175.7	177.2	178.4	179.5	183.3	183.4	184.8	188.3	186.7	188.9	191.3	190.4	192.5	195.5	195.6	198.1	-0.1%

1/ Weighted average price delivered to U.S. refiners.
2/ Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
3/ E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
4/ Sales weighted-average price for all grades. Includes Federal, State, and local taxes.
5/ Includes only kerosene type.
6/ Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
7/ Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
8/ Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
Sources: 2004 and 2005 imported low sulfur light crude oil price: Energy Information Administration (EIA), Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." 2004 and 2005 imported crude oil price: EIA, Annual Energy Review 2005, DOE/EIA-0384(2005) (Washington, DC, July 2006). 2004 and 2005 prices for motor gasoline, distillate fuel oil, and jet fuel are based on: EIA, Petroleum Marketing Annual 2005, DOE/EIA-0487(2005) (Washington, DC, August 2006). 2004 and 2005 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2004 and 2005 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2004 and 2005 ethanol prices "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2004 and 2005 ethanol prices derived from weekly spot prices in the Oxy Fuel News. 2004 and 2005 wholesale ethanol prices derived from Bloomburg U.S. average rack price. Projections: EIA, AEO2007 National Energy Modeling System run aeo2007.d112106a.

HEARING EXHIBIT - 00000174

FMPA-POD1-00017

Table 12. Petroleum Product Prices
(2005 cents per gallon, unless otherwise noted)

Attachment POD-1 ef. Table 12 Petroleum Product Prices - S.280 - Core Case

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Crude Oil Prices (2005 dollars per barrel)																											
Imported Low-Sulfur Light Crude Oil 1/	42.87	56.76	69.11	66.71	64.09	60.61	57.13	53.99	51.38	49.99	49.29	49.52	49.75	50.42	51.26	51.57	52.04	52.73	53.43	54.38	55.07	55.77	56.47	56.95	57.41	57.87	58.34
Imported Crude Oil 1/	37.09	49.19	61.75	59.49	57.23	54.21	51.20	48.48	46.22	45.01	44.41	44.61	44.81	45.22	45.64	46.05	46.47	47.08	47.71	48.33	48.94	49.57	49.97	50.40	50.80	51.21	51.63
Delivered Sector Product Prices																											
Residential																											
Liquefied Petroleum Gases	156.9	166.3	182.3	210.9	211.0	207.1	205.1	202.5	199.6	197.1	197.3	196.5	197.2	198.4	197.7	197.8	197.7	197.8	199.1	200.0	200.1	200.9	201.5	201.6	201.5	201.5	202.6
Distillate Fuel Oil	178.8	204.3	234.5	241.3	232.4	216.8	204.7	193.8	183.7	173.0	171.6	172.4	173.0	174.5	175.8	180.5	179.8	182.1	185.0	184.0	186.0	186.1	187.6	189.1	189.9	190.8	191.5
Commercial																											
Distillate Fuel Oil	145.0	175.4	202.3	209.7	196.9	183.2	174.2	165.0	155.2	148.8	145.2	146.0	147.8	148.1	149.5	154.7	153.6	155.9	160.6	156.6	160.9	164.2	162.9	164.9	169.6	168.6	172.1
Residual Fuel Oil	93.5	126.0	151.2	118.2	119.3	114.9	112.9	105.8	103.4	89.4	94.3	97.0	96.4	98.5	100.2	104.4	105.6	108.1	110.3	108.2	110.2	107.1	109.1	110.6	111.6	108.2	109.3
Residual Fuel Oil (2005 dollars per barrel)	39.29	52.90	63.50	49.66	50.12	48.25	47.40	44.44	43.41	37.55	39.61	40.75	40.50	41.38	42.08	43.86	44.36	45.39	46.35	45.43	46.28	45.00	45.83	46.44	46.86	45.42	45.90
Industrial 2/																											
Liquefied Petroleum Gases	96.3	146.2	163.4	150.4	149.8	145.0	142.7	139.3	139.9	138.1	138.0	137.5	138.7	140.2	140.5	141.1	141.1	141.8	143.3	144.5	145.5	146.9	148.0	148.9	149.4	150.4	152.3
Distillate Fuel Oil	152.2	181.1	209.6	211.9	194.6	182.9	177.1	171.8	175.9	173.7	168.9	170.6	174.7	174.9	177.8	185.5	184.9	189.0	196.5	192.8	200.8	208.7	208.4	213.6	224.1	224.5	233.9
Residual Fuel Oil	86.4	116.3	139.8	150.6	148.0	143.3	137.4	132.2	141.2	134.1	135.4	137.2	138.8	142.7	144.6	149.3	152.4	156.2	159.2	161.2	165.2	169.0	172.2	176.5	180.8	184.3	190.4
Residual Fuel Oil (2005 dollars per barrel)	36.30	48.86	58.73	63.26	62.16	60.21	57.70	55.54	59.30	56.32	56.87	57.62	58.30	59.95	60.75	62.70	63.99	65.60	66.85	67.69	69.40	70.99	72.34	74.12	75.94	77.42	79.97
Transportation																											
Liquefied Petroleum Gases	169.5	206.1	231.0	195.4	196.4	192.8	211.0	208.3	212.5	210.0	210.4	209.9	211.0	212.8	212.6	213.1	214.0	214.9	217.1	219.1	220.3	222.2	224.1	225.7	227.2	228.9	231.8
Ethanol (E85) 3/	198.4	219.2	235.4	274.6	257.9	242.8	235.3	226.4	220.4	212.4	208.9	200.0	201.5	197.4	198.6	200.5	199.2	199.7	204.0	204.2	206.2	207.5	208.4	210.1	212.5	214.4	219.0
Ethanol Wholesale Price	177.2	180.4	248.0	263.0	221.3	217.0	196.2	184.3	174.4	173.4	169.8	166.7	166.4	165.5	164.1	162.7	162.7	161.1	159.0	160.0	158.2	156.6	156.0	154.5	153.7	152.8	152.4
Motor Gasoline 4/	195.2	231.6	262.7	263.0	240.3	223.7	217.7	208.6	213.8	212.5	204.0	205.7	208.4	206.1	210.4	218.0	213.9	216.8	223.9	223.1	228.3	234.6	234.1	239.2	246.9	248.5	255.6
Jet Fuel 5/	124.4	177.4	201.9	175.0	157.4	149.6	146.6	140.2	147.9	147.4	144.9	147.0	149.5	150.0	153.4	160.5	159.9	163.8	170.8	170.6	175.8	182.5	183.6	188.6	194.8	197.2	204.1
Diesel Fuel (distillate fuel oil) 6/	187.1	241.3	272.0	267.4	247.2	234.7	229.8	219.6	223.9	222.3	216.4	218.0	222.3	221.3	224.2	231.7	230.3	234.1	241.9	236.9	245.3	253.5	252.3	257.2	268.7	267.7	277.8
Residual Fuel Oil	72.7	82.4	107.2	134.1	134.7	127.2	119.7	115.2	123.8	120.3	120.8	120.9	122.8	127.1	127.9	131.1	134.3	138.3	141.5	145.2	149.7	155.5	161.1	164.7	168.4	174.4	179.0
Residual Fuel Oil (2005 dollars per barrel)	30.51	34.62	45.03	56.30	56.59	53.41	50.28	48.36	52.01	50.52	50.73	50.78	51.56	53.37	53.70	55.08	56.39	58.07	59.45	60.97	62.89	65.30	67.67	69.16	70.72	73.24	75.20
Electric Power 7/																											
Distillate Fuel Oil	132.7	158.2	183.6	197.3	188.5	173.9	161.7	150.2	150.8	140.6	140.2	141.1	142.9	146.5	149.2	154.9	156.3	160.2	164.2	166.7	171.0	174.9	178.8	183.2	187.3	192.2	196.4
Residual Fuel Oil	75.6	105.5	117.5	108.9	109.5	103.5	97.8	92.2	136.6	119.4	129.1	134.8	140.0	145.5	151.2	161.0	166.5	173.9	177.5	183.6	191.2	198.4	206.6	212.3	221.4	231.4	234.8
Residual Fuel Oil (2005 dollars per barrel)	31.76	44.30	49.33	45.75	46.00	43.48	41.07	38.70	57.39	50.17	54.21	56.61	58.80	61.13	63.52	67.62	69.92	73.02	74.57	77.11	80.31	83.31	86.77	89.16	92.97	97.21	98.60
Refined Petroleum Product Prices 8/																											
Liquefied Petroleum Gases	109.3	150.7	167.7	163.2	162.8	158.2	156.5	153.4	153.4	151.6	151.6	151.1	152.4	153.9	154.0	154.6	154.7	155.3	156.8	158.0	158.9	160.2	161.3	162.1	162.5	163.3	165.1
Motor Gasoline 4/	195.0	231.1	262.1	262.9	240.3	223.7	217.7	208.6	213.7	212.5	203.9	205.6	208.3	206.0	210.4	217.9	213.8	216.7	223.8	223.1	228.2	234.5	234.0	239.1	246.8	248.4	255.5
Jet Fuel 5/	124.4	177.4	201.9	175.0	157.4	149.6	146.8	140.2	147.9	147.4	144.9	147.0	149.5	150.0	153.4	160.5	159.9	163.8	170.8	170.6	175.8	182.5	183.6	188.6	194.8	197.2	204.1
Distillate Fuel Oil	178.2	223.9	254.0	251.7	234.2	221.6	214.9	205.3	208.2	206.5	201.5	203.1	207.1	206.8	209.6	217.0	216.0	219.8	227.2	223.1	230.9	238.5	237.9	242.7	253.3	253.0	262.3
Residual Fuel Oil	76.7	99.4	118.5	125.2	125.5	119.0	112.6	107.1	125.8	118.6	121.2	122.5	124.4	128.6	130.0	134.1	137.2	141.3	144.4	147.4	151.8	156.4	161.7	165.2	168.8	173.7	178.1
Residual Fuel Oil (2005 dollars per barrel)	32.22	41.75	49.78	52.57	52.72	49.98	47.30	44.98	52.84	49.80	50.91	51.45	52.25	54.00	54.62	56.33	57.63	59.34	60.67	61.89	63.75	65.69	67.91	69.38	70.90	72.94	74.81
Average	168.5	204.4	232.6	230.5	212.6	201.0	195.0	187.0	192.6	191.0	185.7	187.1	189.8	189.2	192.7	199.3	197.3	200.4	206.8	205.8	211.1	217.1	217.3	221.8	229.1	230.4	237.4

1/ Weighted average price delivered to U.S. refiners.
2/ Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
3/ E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
4/ Sales weighted-average price for all grades. Includes Federal, State, and local taxes.
5/ Includes only kerosene type.
6/ Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
7/ Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
8/ Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
Sources: 2004 and 2005 imported low sulfur light crude oil price: Energy Information Administration (EIA), Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." 2004 and 2005 imported crude oil price: EIA, Annual Energy Review 2005, DOE/EIA-0384(2005) (Washington, DC, July 2006). 2004 and 2005 prices for motor gasoline, distillate fuel oil, and jet fuel are based on: EIA, Petroleum Marketing Annual 2005, DOE/EIA-0487(2005) (Washington, DC, August 2006). 2004 and 2005 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2004 and 2005 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2004 and 2005 ethanol prices "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2004 and 2005 ethanol prices derived from weekly spot prices in the Oxy Fuel News. 2004 and 2005 wholesale ethanol prices derived from Bloomburg U.S. average rack price. Projections: EIA, AEO2007 National Energy Modeling System run s280.d060107a.

HEARING EXHIBIT - 00000175

Table 12. Petroleum Product Prices
(2005 cents per gallon, unless otherwise noted)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Crude Oil Prices (2005 dollars per barrel)																											
Imported Low-Sulfur Light Crude Oil	42.87	56.76	69.11	66.71	64.09	60.61	57.13	53.99	51.38	49.99	49.29	49.83	49.75	50.76	51.31	51.57	52.04	52.73	53.43	54.38	55.07	55.77	56.47	56.95	57.41	57.87	58.34
Imported Crude Oil 1/	37.09	49.19	61.75	59.49	57.23	54.21	51.20	48.48	46.22	45.01	44.43	44.61	44.81	45.22	45.64	46.05	46.47	47.08	47.71	48.33	48.94	49.57	49.97	50.40	50.80	51.21	51.63
Delivered Sector Product Prices																											
Residential																											
Liquefied Petroleum Gases	156.9	166.3	182.3	210.9	211.7	207.3	205.5	203.4	199.8	197.0	196.3	196.6	196.6	197.3	196.6	196.4	197.0	197.5	198.0	198.5	198.4	199.5	200.7	202.7	203.1	201.7	202.1
Distillate Fuel Oil	178.8	204.3	234.5	241.2	232.7	216.6	204.5	194.1	183.8	173.1	171.0	172.2	173.3	174.3	175.6	179.3	179.6	181.3	184.9	183.8	184.8	185.3	186.5	187.6	189.0	190.7	190.2
Commercial																											
Distillate Fuel Oil	145.0	175.4	202.3	209.6	197.0	183.0	174.4	165.1	155.3	148.7	144.5	145.8	147.6	147.6	149.3	153.1	153.1	154.9	160.6	156.7	159.9	162.5	161.9	164.7	169.3	168.1	171.3
Residual Fuel Oil	93.5	126.0	151.2	118.2	120.0	114.9	112.9	105.8	103.4	89.4	94.3	97.1	96.4	98.5	100.2	104.4	105.6	108.1	110.3	108.2	110.2	107.1	109.1	110.6	111.5	108.2	109.3
Residual Fuel Oil (2005 dollars per	39.29	52.90	63.50	49.66	50.41	48.25	47.40	44.44	43.41	37.56	39.61	40.77	40.50	41.38	42.05	43.84	44.36	45.40	46.34	45.43	46.28	44.99	45.83	46.43	46.84	45.42	45.89
Industrial 2/																											
Liquefied Petroleum Gases	96.3	146.2	163.4	150.4	150.4	145.3	143.1	140.3	141.5	139.1	138.5	139.0	139.8	140.9	141.3	142.0	142.9	144.1	145.1	146.3	145.7	147.5	149.2	152.3	153.8	153.1	154.8
Distillate Fuel Oil	152.2	181.1	209.6	211.8	196.8	182.7	177.3	171.8	180.9	177.6	173.0	176.1	180.3	181.1	184.6	191.4	192.7	197.2	206.6	203.8	206.2	213.1	214.5	221.8	232.5	233.1	243.0
Residual Fuel Oil	86.4	116.3	139.8	150.6	149.4	143.4	137.5	132.2	146.7	138.9	141.1	144.2	146.1	150.7	153.2	158.2	162.6	167.4	171.3	173.5	172.4	176.2	180.6	185.4	190.1	194.8	201.0
Residual Fuel Oil (2005 dollars per	36.30	48.86	58.73	63.24	62.77	60.23	57.74	55.53	61.60	58.35	59.24	60.56	61.38	63.30	64.36	66.45	68.28	70.29	71.95	72.88	72.41	74.01	75.84	77.87	79.83	81.80	84.41
Transportation																											
Liquefied Petroleum Gases	169.5	206.1	231.0	195.4	197.1	193.1	211.3	209.2	215.2	212.1	212.1	213.0	213.7	215.3	215.4	216.0	217.7	219.5	221.4	223.4	221.8	224.4	227.2	231.0	233.3	233.9	236.5
Ethanol (E85) 3/	198.4	219.2	235.4	274.5	259.8	244.4	237.2	227.8	217.3	219.6	208.3	204.8	200.0	197.4	198.9	201.0	201.1	205.1	206.4	204.7	207.2	210.8	210.7	210.2	214.5	215.7	222.6
Ethanol Wholesale Price	177.2	180.4	248.0	262.9	220.3	216.5	192.4	181.1	174.4	173.3	166.1	164.5	162.5	160.8	159.4	158.7	157.7	158.2	156.3	152.4	155.7	155.3	153.7	148.3	148.3	147.0	149.8
Motor Gasoline 4/	195.2	231.6	262.7	262.9	240.3	223.5	217.2	208.1	217.5	215.6	207.4	210.1	212.9	210.5	215.3	222.2	220.4	224.3	231.2	230.9	231.8	238.8	239.1	244.5	253.1	254.2	262.2
Jet Fuel 5/	124.4	177.4	201.9	175.0	157.5	149.3	146.8	140.4	152.5	151.1	149.1	152.2	155.2	156.1	159.9	166.3	167.3	171.9	178.9	179.9	180.2	187.5	189.4	194.9	203.1	206.2	213.3
Diesel Fuel (distillate fuel oil) 6	187.1	241.3	272.0	267.2	247.4	234.2	230.3	219.6	228.8	226.2	220.3	223.5	227.7	227.5	230.9	237.6	237.9	242.2	251.8	247.7	250.5	257.4	258.1	265.5	277.0	276.5	287.2
Residual Fuel Oil	72.7	82.4	107.2	134.0	134.9	127.2	119.6	115.0	129.3	124.7	126.4	127.8	130.0	135.0	136.5	140.1	144.7	149.4	153.9	158.5	157.8	163.3	169.0	174.5	181.8	187.7	192.8
Residual Fuel Oil (2005 dollars per	30.51	34.62	45.03	56.29	56.64	53.42	50.25	48.31	54.30	52.38	53.07	53.69	54.62	56.69	57.32	58.84	60.79	62.75	64.64	66.56	66.29	68.57	70.97	73.27	76.36	78.85	80.97
Electric Power 7/																											
Distillate Fuel Oil	132.7	158.2	183.6	197.2	188.9	173.9	161.7	150.6	155.6	144.6	144.9	147.0	149.3	153.0	156.1	161.0	163.9	167.8	173.7	177.0	176.3	180.5	185.3	190.4	196.0	201.3	206.7
Residual Fuel Oil	75.6	105.5	117.8	108.9	109.8	103.2	97.2	91.8	146.5	125.3	130.5	140.8	151.7	156.1	164.3	179.2	187.2	190.1	193.8	202.6	206.4	215.5	223.2	232.1	242.3	248.3	252.0
Residual Fuel Oil (2005 dollars per	31.76	44.30	49.48	45.74	46.12	43.35	40.84	38.55	61.52	52.61	54.81	59.14	63.70	65.58	68.99	75.24	78.64	79.85	81.40	85.08	86.68	90.50	93.76	97.50	101.77	104.27	105.83
Refined Petroleum Product Prices 8/																											
Liquefied Petroleum Gases	109.3	150.7	167.7	163.2	163.2	158.5	156.8	154.3	154.7	152.4	151.8	152.4	153.1	154.3	154.6	155.1	156.1	157.1	158.1	159.3	158.8	160.5	162.2	165.1	166.4	165.6	167.2
Motor Gasoline 4/	195.0	231.1	262.1	262.9	240.3	223.5	217.2	208.1	217.4	215.6	207.4	210.1	212.8	210.5	215.2	222.1	220.3	224.2	231.2	230.9	231.7	238.7	239.0	244.4	253.0	254.1	262.1
Jet Fuel 5/	124.4	177.4	201.9	175.0	157.5	149.3	146.8	140.4	152.5	151.1	149.1	152.2	155.2	156.1	159.9	166.3	167.3	171.9	178.9	179.9	180.2	187.5	189.4	194.9	203.1	206.2	213.3
Distillate Fuel Oil	178.2	223.9	254.0	251.5	234.3	221.3	215.3	205.4	212.5	209.9	204.9	207.8	211.8	212.1	215.4	222.1	222.8	227.0	236.1	232.7	235.5	242.2	243.1	250.1	260.7	260.8	270.6
Residual Fuel Oil	76.7	99.4	118.7	125.1	125.9	118.8	112.1	106.5	131.2	122.8	125.6	128.6	131.3	135.9	138.1	142.5	146.9	151.4	155.6	159.3	159.2	163.5	168.9	174.1	180.8	185.4	190.2
Residual Fuel Oil (2005 dollars per	32.22	41.75	49.84	52.56	52.86	49.91	47.09	44.73	55.10	51.58	52.76	54.01	55.15	57.06	57.98	59.86	61.70	63.57	65.34	66.89	66.85	68.67	70.95	73.14	75.92	77.88	79.90
Average	168.5	204.4	232.6	230.5	212.7	200.8	194.8	186.7	196.2	193.9	188.7	191.3	194.1	193.5	197.3	203.5	203.3	207.1	213.9	213.4	214.5	220.8	221.8	227.3	235.5	236.6	244.1

1/ Weighted average price delivered to U.S. refiners.
2/ Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
3/ E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
4/ Sales weighted-average price for all grades. Includes Federal, State, and local taxes.
5/ Includes only kerosene type.
6/ Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
7/ Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
8/ Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
Sources: 2004 and 2005 imported low sulfur light crude oil price: Energy Information Administration (EIA), Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." 2004 and 2005 imported crude oil price: EIA, Annual Energy Review 2005, DOE/EIA-0384(2005) (Washington, DC, July 2006). 2004 and 2005 prices for motor gasoline, distillate fuel oil, and jet fuel are based on: EIA, Petroleum Marketing Annual 2005, DOE/EIA-0487(2005) (Washington, DC, August 2006). 2004 and 2005 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2004 and 2005 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2004 and 2005 ethanol prices "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2004 and 2005 ethanol prices derived from weekly spot prices in the Oxy Fuel News. 2004 and 2005 wholesale ethanol prices derived from Bloomburg U.S. average rack price. Projections: EIA, AEO2007 National Energy Modeling System run s280nointl.d061507a.

DEADRIN EXHIBIT 2000242

Table 12 Petroleum Product Prices
(2005 cents per gallon, unless otherwise noted)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Crude Oil Prices (2005 dollars per barrel)																											
Imported Low-Sulfur Light Crude Oil	42.87	56.76	69.11	66.71	64.09	60.61	57.13	51.99	51.38	49.99	49.29	49.52	49.75	50.42	50.90	51.57	52.04	52.73	53.43	54.38	55.55	55.77	56.47	56.95	57.41	57.87	59.04
Imported Crude Oil 1/	37.09	49.19	61.75	59.49	57.23	54.21	51.20	48.48	46.22	45.01	44.41	44.61	44.81	45.22	45.64	46.05	46.47	47.08	47.71	48.33	48.94	49.57	49.97	50.40	50.80	51.21	51.63
Delivered Sector Product Prices																											
Residential																											
Liquefied Petroleum Gases	156.9	166.3	182.3	211.0	231.2	207.1	204.2	201.2	199.1	196.6	196.4	196.7	197.3	198.9	198.1	197.9	198.7	199.3	200.9	201.6	203.0	203.5	204.0	205.1	205.2	205.0	204.6
Distillate Fuel Oil	178.8	204.3	234.5	241.3	232.8	217.5	204.6	193.2	183.8	172.7	171.5	171.8	173.4	175.2	176.8	180.5	181.3	182.9	184.8	185.1	186.6	187.0	188.6	191.6	193.4	195.7	196.9
Commercial																											
Distillate Fuel Oil	145.0	175.4	202.3	209.8	197.1	183.9	174.2	164.6	155.3	148.6	145.0	145.7	148.0	148.9	150.8	155.1	154.8	156.6	160.5	158.0	161.2	165.6	164.1	168.9	173.5	173.1	177.3
Residual Fuel Oil	93.5	126.0	151.2	118.3	119.7	114.9	112.8	105.8	103.4	89.4	94.4	97.1	96.5	98.5	100.3	104.5	105.7	108.1	110.3	108.2	110.1	107.2	109.1	110.9	112.0	108.7	109.9
Residual Fuel Oil (2005 dollars per	39.29	52.90	63.50	49.67	50.26	48.25	47.37	44.43	43.43	37.56	39.63	40.77	40.51	41.37	42.11	43.87	44.38	45.40	46.34	45.43	46.26	45.01	45.83	46.56	47.05	45.67	46.15
Industrial 2/																											
Liquefied Petroleum Gases	96.3	146.2	163.4	150.4	150.0	144.9	141.8	138.1	137.8	136.1	136.0	136.1	137.2	138.7	138.8	139.1	139.9	140.8	142.5	143.5	145.3	146.2	147.1	148.6	149.3	149.4	149.5
Distillate Fuel Oil	152.2	181.1	209.6	211.9	194.7	183.5	177.1	171.7	170.6	168.1	163.2	165.0	169.2	169.6	172.7	179.0	178.1	181.0	187.7	184.6	190.4	199.2	197.5	205.3	213.8	213.5	222.0
Residual Fuel Oil	86.4	116.3	139.8	150.7	147.8	143.5	137.0	132.2	135.0	127.8	129.3	131.3	132.2	135.4	137.1	140.7	143.3	146.2	148.2	149.4	153.7	156.3	158.9	163.8	166.8	170.5	174.2
Residual Fuel Oil (2005 dollars per	36.30	48.86	58.73	63.28	62.07	60.26	57.55	55.53	56.69	53.68	54.30	55.13	55.53	56.85	57.58	59.10	60.19	61.40	62.25	62.74	64.55	65.66	66.72	68.78	70.04	71.63	73.15
Transportation																											
Liquefied Petroleum Gases	169.5	206.1	231.0	195.4	196.6	192.8	210.1	207.1	209.0	206.6	206.9	207.2	208.1	210.0	209.4	209.4	210.8	211.9	214.0	215.5	217.5	218.8	220.1	222.0	223.1	224.0	224.8
Ethanol (E85) 3/	198.4	219.2	235.4	274.6	256.0	240.5	236.5	223.4	217.5	207.5	206.3	199.7	199.9	194.5	196.0	198.3	198.3	198.8	200.9	199.9	202.6	204.3	204.9	204.6	208.5	208.9	213.0
Ethanol Wholesale Price	177.2	180.4	248.0	262.9	222.6	218.4	210.4	185.1	180.1	173.5	170.2	169.4	167.8	166.7	165.7	165.4	165.1	165.3	163.0	161.7	161.8	160.9	160.7	156.4	157.5	157.7	157.2
Motor Gasoline 4/	195.2	231.6	262.7	263.0	240.5	225.2	219.3	208.6	209.8	208.0	199.5	201.8	204.2	202.1	206.1	213.8	208.3	210.9	217.0	216.0	220.4	226.4	224.7	231.7	237.9	238.4	245.7
Jet Fuel 5/	124.4	177.4	201.9	175.1	157.4	150.4	146.3	140.2	142.6	142.0	139.6	141.5	144.2	144.8	148.4	154.6	153.4	156.3	162.6	162.8	166.2	171.8	173.2	179.6	185.0	187.1	193.0
Diesel Fuel (distillate fuel oil) 6	187.1	241.3	272.0	267.4	247.3	235.6	230.2	219.7	218.6	216.8	210.7	212.4	216.8	216.3	219.3	225.6	223.6	226.4	233.3	229.2	235.2	244.4	241.6	249.4	258.5	256.8	266.1
Residual Fuel Oil	72.7	82.4	107.2	134.1	134.8	127.3	119.4	114.8	117.6	114.0	114.7	115.5	116.2	119.7	120.5	122.5	125.3	128.3	130.5	134.1	137.5	142.1	145.1	150.0	154.5	159.8	163.0
Residual Fuel Oil (2005 dollars per	30.51	34.62	45.03	56.32	56.62	53.48	50.15	48.23	49.39	47.87	48.18	48.53	48.80	50.28	50.61	51.44	52.63	53.89	54.82	56.33	57.74	59.70	60.95	62.98	64.88	67.12	68.45
Electric Power 7/																											
Distillate Fuel Oil	132.7	158.2	183.6	197.3	189.0	174.7	161.1	150.0	145.6	135.0	134.9	136.0	137.2	141.0	143.7	147.6	150.0	152.4	155.1	157.9	161.1	164.0	167.4	172.8	176.5	180.9	184.5
Residual Fuel Oil	75.6	105.5	117.4	108.9	109.7	103.8	97.9	92.9	123.7	108.5	113.7	130.7	132.7	139.5	145.3	151.6	154.6	159.5	165.3	165.6	173.0	178.1	183.3	187.3	193.8	200.2	202.9
Residual Fuel Oil (2005 dollars per	31.76	44.30	49.33	45.76	46.07	43.62	41.11	39.03	51.96	45.58	47.77	54.88	55.75	58.59	61.04	63.68	64.94	67.01	69.44	69.55	72.68	74.79	76.98	78.66	81.40	84.09	85.21
Refined Petroleum Product Prices 8/																											
Liquefied Petroleum Gases	109.3	150.7	167.7	163.2	162.8	158.1	155.5	152.1	151.6	149.8	149.8	150.0	151.1	152.7	152.8	153.0	153.9	154.7	156.5	157.5	159.2	160.1	160.9	162.4	163.0	163.1	163.2
Motor Gasoline 4/	195.0	231.1	262.1	262.9	240.5	225.2	219.3	208.6	209.8	208.0	199.5	201.8	204.2	202.0	206.1	213.7	208.2	210.9	216.9	216.0	220.3	226.4	224.7	231.6	237.9	238.4	245.6
Jet Fuel 5/	124.4	177.4	201.9	175.1	157.4	150.4	146.3	140.2	142.6	142.0	139.6	141.5	144.2	144.8	148.4	154.6	153.4	156.3	162.6	162.8	166.2	171.8	173.2	179.6	185.0	187.1	193.0
Distillate Fuel Oil	178.2	223.9	254.0	251.7	234.3	222.3	215.2	205.3	203.6	201.8	196.6	198.3	202.4	202.5	205.5	211.8	210.3	213.2	219.8	216.4	222.0	230.5	228.5	235.9	244.4	243.7	252.1
Residual Fuel Oil	76.7	99.4	118.5	125.2	125.6	119.3	112.6	107.6	119.4	112.0	114.3	117.8	118.5	122.1	123.6	126.4	129.0	132.1	134.6	137.0	140.7	144.3	147.4	151.8	156.0	160.2	163.2
Residual Fuel Oil (2005 dollars per	32.22	41.75	49.78	52.58	52.77	50.10	47.29	45.20	50.13	47.06	48.01	49.46	49.76	51.30	51.91	53.07	54.19	55.50	56.52	57.55	59.10	60.62	61.90	63.77	65.50	67.28	68.55
Average	168.5	204.4	232.6	230.5	212.8	201.9	195.7	186.9	188.6	186.7	181.3	183.2	185.8	185.5	188.9	195.2	192.1	194.8	200.4	199.5	203.8	209.6	208.8	215.2	221.2	221.8	228.3

1/ Weighted average price delivered to U.S. refiners.
2/ Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
3/ E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
4/ Sales weighted-average price for all grades. Includes Federal, State, and local taxes.
5/ Includes only kerosene type.
6/ Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
7/ Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
8/ Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
Sources: 2004 and 2005 imported low sulfur light crude oil price: Energy Information Administration (EIA), Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." 2004 and 2005 imported crude oil price: EIA, Annual Energy Review 2005, DOE/EIA-0384(2005) (Washington, DC, July 2006). 2004 and 2005 prices for motor gasoline, distillate fuel oil, and jet fuel are based on: EIA, Petroleum Marketing Annual 2005, DOE/EIA-0487(2005) (Washington, DC, August 2006). 2004 and 2005 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2004 and 2005 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2004 and 2005 ethanol prices "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2004 and 2005 ethanol prices derived from weekly spot prices in the Oxy Fuel News. 2004 and 2005 wholesale ethanol prices derived from Bloomburg U.S. average rack price. Projections: EIA, AEO2007 National Energy Modeling System run s280strow.d060207a.

HEARING EXHIBIT - 00000177

Table 12. Petroleum Product Prices
(2005 cents per gallon, unless otherwise noted)

Attachment POD-1 of Table 12 Petroleum Product Prices. S 280 - No Nuclear Case

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Crude Oil Prices (2005 dollars per barrel)																											
Imported Low-Sulfur Light Crude Oil 1/	42.87	56.76	69.11	66.71	64.09	60.61	57.13	53.99	51.38	49.99	49.29	49.52	49.75	50.42	51.28	51.57	52.04	52.73	53.43	54.38	55.07	55.77	56.47	56.95	57.41	57.87	58.34
Imported Crude Oil 1/	37.09	49.19	61.75	59.49	57.23	54.21	51.20	48.48	46.22	45.01	44.41	44.61	44.81	45.22	45.64	46.05	46.47	47.08	47.71	48.33	48.94	49.57	49.97	50.40	50.80	51.21	51.63
Delivered Sector Product Prices																											
Residential																											
Liquefied Petroleum Gases	156.9	166.3	182.3	210.9	211.7	207.4	205.1	202.3	199.4	197.2	197.6	197.0	197.6	198.4	198.4	198.1	198.5	198.4	199.3	200.0	200.8	201.1	202.3	203.3	204.4	205.0	205.5
Distillate Fuel Oil	178.8	204.3	234.5	241.3	232.6	216.9	204.2	193.6	183.8	173.1	171.6	172.4	173.1	174.6	175.8	180.3	179.9	182.3	184.9	184.0	186.0	186.3	187.3	188.5	189.6	191.5	192.6
Commercial																											
Distillate Fuel Oil	145.0	175.4	202.3	209.7	197.0	183.2	173.9	164.9	155.3	148.9	145.2	145.9	147.9	148.1	149.4	154.4	153.7	156.0	160.4	157.0	160.9	164.4	162.7	165.7	169.6	168.8	172.6
Residual Fuel Oil	93.5	126.0	151.2	118.2	120.0	114.8	112.9	105.8	103.4	89.4	94.3	97.0	96.4	98.5	100.2	104.4	105.6	108.1	110.3	108.2	110.2	107.1	109.1	110.6	111.6	108.2	109.3
Residual Fuel Oil (2005 dollars per barrel)	39.29	52.90	63.50	49.66	50.41	48.20	47.40	44.43	43.41	37.56	39.63	40.76	40.50	41.37	42.10	43.86	44.37	45.40	46.35	45.43	46.29	45.00	45.84	46.43	46.87	45.43	45.91
Industrial 2/																											
Liquefied Petroleum Gases	96.3	146.2	163.4	150.4	150.4	145.3	142.6	139.2	139.7	138.1	138.7	138.3	139.4	140.7	141.4	141.9	142.3	142.9	144.2	145.1	146.8	147.7	149.4	151.2	153.1	154.4	155.8
Distillate Fuel Oil	152.2	181.1	209.6	211.9	194.7	182.9	176.9	171.8	176.0	173.7	169.3	171.2	175.7	175.7	178.8	186.3	186.2	190.5	197.8	195.1	202.5	211.2	210.3	217.4	226.7	227.1	236.8
Residual Fuel Oil	86.4	116.3	139.8	150.6	148.6	143.3	137.4	132.1	141.1	134.1	136.0	138.3	139.9	143.9	146.2	150.7	153.9	157.8	160.9	162.8	167.2	171.6	174.6	178.9	183.6	187.3	195.8
Residual Fuel Oil (2005 dollars per barrel)	36.30	48.86	58.73	63.26	62.42	60.19	57.72	55.50	59.26	56.34	57.13	58.07	58.74	60.42	61.40	63.31	64.64	66.28	67.58	68.38	70.22	72.07	73.33	75.12	77.11	78.66	82.22
Transportation																											
Liquefied Petroleum Gases	169.5	206.1	231.0	195.4	197.1	193.2	211.0	208.1	212.2	210.0	210.9	210.7	211.8	213.3	213.8	214.1	215.4	216.2	218.1	220.0	221.8	223.5	226.0	228.6	231.3	233.7	236.3
Ethanol (E85) 3/	198.4	219.2	235.4	274.6	257.8	242.8	234.9	226.5	220.5	212.2	210.9	203.5	202.0	199.2	200.0	201.1	200.3	200.8	204.6	204.8	205.0	209.3	209.6	212.8	215.8	218.6	221.3
Ethanol Wholesale Price	177.2	180.4	248.0	263.0	221.4	217.1	195.5	184.1	174.4	173.4	168.6	169.1	166.1	165.4	164.1	162.6	162.6	160.9	158.9	158.1	157.4	156.9	155.6	154.6	153.1	154.2	153.7
Motor Gasoline 4/	195.2	231.6	262.7	263.0	240.2	223.7	217.3	208.7	213.9	212.3	204.6	206.7	209.1	208.8	211.2	218.5	214.8	218.3	225.6	224.2	229.0	236.4	235.9	241.3	248.2	250.0	257.9
Jet Fuel 5/	124.4	177.4	201.9	175.0	157.4	149.6	146.6	140.2	147.9	147.4	145.3	147.7	150.4	150.9	154.4	161.3	160.9	165.2	172.4	172.0	177.3	184.4	185.7	191.2	197.0	200.1	207.6
Diesel Fuel (distillate fuel oil) 6/	187.1	241.3	272.0	267.4	247.3	234.8	229.6	219.6	223.9	222.3	216.8	218.5	223.2	222.2	225.2	232.6	231.6	235.4	243.3	239.3	247.0	255.8	254.1	261.2	271.0	270.4	280.8
Residual Fuel Oil	72.7	82.4	107.2	134.1	134.9	127.2	119.7	115.1	123.7	120.1	121.4	122.3	123.8	128.3	129.4	132.5	135.7	139.8	143.1	147.3	151.8	157.6	162.6	167.3	171.1	178.0	182.9
Residual Fuel Oil (2005 dollars per barrel)	30.51	34.62	45.03	56.31	56.64	53.41	50.27	48.32	51.97	50.43	51.00	51.36	52.00	53.88	54.34	55.67	56.99	58.71	60.10	61.88	63.77	66.21	68.31	70.27	71.87	74.75	76.83
Electric Power 7/																											
Distillate Fuel Oil	132.7	158.2	183.6	197.3	188.8	174.0	161.4	150.2	151.0	140.7	140.6	142.1	143.5	147.4	150.1	155.8	157.8	161.8	165.4	168.5	173.0	177.0	181.0	185.0	189.2	194.5	200.0
Residual Fuel Oil	75.6	105.5	117.5	108.9	109.7	103.3	97.8	92.2	137.1	119.4	129.7	136.8	142.3	149.9	154.7	162.1	165.0	172.2	176.5	181.2	185.6	193.4	199.6	209.9	214.5	225.0	230.8
Residual Fuel Oil (2005 dollars per barrel)	31.76	44.30	49.33	45.75	46.09	43.40	41.08	38.71	57.60	50.17	54.48	57.48	59.75	62.96	64.97	68.09	69.31	72.31	74.15	76.09	77.94	81.25	83.84	88.15	90.08	94.51	96.92
Refined Petroleum Product Prices 8/																											
Liquefied Petroleum Gases	109.3	150.7	167.7	163.2	163.3	158.5	156.4	153.2	153.2	151.6	152.3	151.9	153.0	154.2	154.9	155.3	155.8	156.3	157.6	158.5	160.0	161.0	162.5	164.2	166.0	167.2	168.5
Motor Gasoline 4/	195.0	231.1	262.1	263.0	240.2	223.7	217.3	208.7	213.9	212.3	204.6	206.6	209.0	208.8	211.1	218.4	214.8	218.2	225.6	224.1	228.9	236.3	235.8	241.2	248.1	249.9	257.8
Jet Fuel 5/	124.4	177.4	201.9	175.0	157.4	149.6	146.6	140.2	147.9	147.4	145.3	147.7	150.4	150.9	154.4	161.3	160.9	165.2	172.4	172.0	177.3	184.4	185.7	191.2	197.0	200.1	207.6
Distillate Fuel Oil	178.2	223.9	254.0	251.7	234.2	221.6	214.7	205.3	208.2	206.6	201.8	203.6	207.9	207.5	210.4	217.7	217.0	221.0	228.4	225.1	232.3	240.6	239.4	246.2	255.5	255.4	265.0
Residual Fuel Oil	76.7	99.4	118.5	125.2	125.8	118.9	112.7	107.1	125.8	118.5	121.8	123.8	125.5	130.0	131.6	135.4	138.4	142.5	145.7	149.0	153.3	158.1	162.7	167.3	171.0	176.5	181.6
Residual Fuel Oil (2005 dollars per barrel)	32.22	41.75	49.78	52.57	52.83	49.93	47.32	44.97	52.84	49.75	51.16	51.99	52.70	54.58	55.27	56.87	58.11	59.85	61.21	62.59	64.39	66.39	68.35	70.27	71.81	74.14	76.28
Average	168.5	204.4	232.6	230.5	212.7	201.0	194.8	187.1	192.7	191.0	186.2	187.9	190.6	190.0	193.5	199.9	198.2	201.7	208.3	207.0	212.1	218.8	218.8	224.2	230.8	232.5	240.0

1/ Weighted average price delivered to U.S. refiners.
2/ Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
3/ E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
4/ Sales weighted-average price for all grades. Includes Federal, State, and local taxes.
5/ Includes only kerosene type.
6/ Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
7/ Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
8/ Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
Sources: 2004 and 2005 imported low sulfur light crude oil price: Energy Information Administration (EIA), Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." 2004 and 2005 imported crude oil price: EIA, Annual Energy Review 2005, DOE/EIA-0384(2005) (Washington, DC, July 2006). 2004 and 2005 prices for motor gasoline, distillate fuel oil, and jet fuel are based on: EIA, Petroleum Marketing Annual 2005, DOE/EIA-0487(2005) (Washington, DC, August 2006). 2004 and 2005 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2004 and 2005 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2004 and 2005 ethanol prices "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2004 and 2005 ethanol prices derived from weekly spot prices in the Oxy Fuel News. 2004 and 2005 wholesale ethanol prices derived from Bloomburg U.S. average rack price. Projections: EIA, AEO2007 National Energy Modeling System run s280nuc.d060207a.

HEARING EXHIBIT - 00000178

Table 12. Petroleum Product Prices
(2005 cents per gallon, unless otherwise noted)

Attachment POD-1 of Table 12 Petroleum Product Prices S.280 - Low Discount Case

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Crude Oil Prices (2005 dollars per barrel)																											
Imported Low-Sulfur Light Crude Oil 1/	42.87	56.76	69.11	66.71	64.09	60.61	57.13	53.99	51.38	49.99	49.29	49.82	49.75	50.42	51.26	51.57	52.04	52.73	53.43	54.38	55.07	55.77	56.47	56.95	57.41	57.87	59.01
Imported Crude Oil 1/	37.09	49.19	61.75	59.49	57.23	54.21	51.20	48.48	46.22	45.01	44.41	44.61	44.81	45.22	45.64	46.05	46.47	47.08	47.71	48.33	48.94	49.57	49.97	50.40	50.80	51.21	51.63
Delivered Sector Product Prices																											
Residential																											
Liquefied Petroleum Gases	156.9	166.3	182.3	210.9	211.2	207.4	205.0	202.9	199.2	197.3	196.7	196.7	197.4	198.1	197.6	197.2	197.2	197.1	197.9	198.7	199.1	199.9	200.8	202.0	202.1	202.1	202.0
Distillate Fuel Oil	178.8	204.3	234.5	241.4	232.5	216.7	204.3	193.9	183.8	172.4	171.1	172.1	173.2	174.5	175.5	180.4	180.0	182.3	184.9	184.0	186.4	186.4	188.3	189.8	192.3	194.9	197.3
Commercial																											
Distillate Fuel Oil	145.0	175.4	202.3	209.8	196.8	183.2	174.1	165.1	155.2	148.6	144.8	145.8	147.9	148.0	149.0	154.6	153.7	156.0	160.5	157.4	161.2	165.0	163.7	166.2	172.3	173.1	177.3
Residual Fuel Oil	93.5	126.0	151.2	118.3	120.0	114.9	112.9	105.8	103.4	89.4	94.3	97.0	96.4	98.5	100.2	104.4	105.6	108.1	110.3	108.2	110.2	107.1	109.1	110.6	111.8	108.6	109.8
Residual Fuel Oil (2005 dollars per barrel)	39.29	52.90	63.50	49.67	50.41	48.26	47.41	44.46	43.42	37.56	39.60	40.76	40.51	41.37	42.10	43.85	44.36	45.40	46.34	45.43	46.27	44.99	45.83	46.45	46.95	45.61	46.13
Industrial 2/																											
Liquefied Petroleum Gases	96.3	146.2	163.4	150.4	150.0	145.3	142.7	139.8	140.4	139.1	138.4	138.5	139.6	140.5	140.5	140.6	140.6	140.8	141.4	142.4	143.3	144.3	145.3	146.6	147.0	147.2	147.4
Distillate Fuel Oil	152.2	181.1	209.6	212.0	194.5	182.9	177.2	172.0	178.8	176.5	171.3	173.4	177.2	176.6	178.2	186.0	184.8	187.8	194.3	191.1	196.6	204.0	201.7	206.3	216.1	216.5	223.3
Residual Fuel Oil	86.4	116.3	139.8	150.7	149.5	143.5	137.6	132.5	144.6	137.6	138.6	140.8	141.8	144.9	146.3	149.9	152.1	155.1	157.0	157.1	159.8	162.6	163.5	166.0	169.1	171.9	176.2
Residual Fuel Oil (2005 dollars per barrel)	36.30	48.86	58.73	63.30	62.79	60.29	57.78	55.65	60.75	57.81	58.22	59.15	59.56	60.86	61.45	62.94	63.89	65.12	65.92	66.00	67.12	68.29	68.68	69.71	71.04	72.20	74.01
Transportation																											
Liquefied Petroleum Gases	169.5	206.1	231.0	195.4	196.6	193.2	210.9	208.8	213.5	211.6	211.4	211.7	212.5	213.5	213.2	212.9	213.3	213.7	214.8	216.1	216.8	218.1	219.5	221.3	221.9	222.5	222.9
Ethanol (E85) 3/	198.4	219.2	235.4	274.8	259.8	244.7	237.0	227.9	213.9	214.1	207.4	203.8	197.6	197.6	199.9	200.1	199.0	202.9	200.6	201.6	204.0	206.0	204.6	205.2	209.0	209.4	211.5
Ethanol Wholesale Price	177.2	180.4	248.0	262.8	220.1	216.6	194.5	183.6	174.8	173.3	166.7	166.6	162.3	164.3	164.1	162.7	163.1	162.2	159.8	159.9	159.2	158.1	157.6	154.6	155.4	155.2	155.5
Motor Gasoline 4/	195.2	231.6	262.7	263.0	240.1	223.6	217.4	208.4	216.0	214.8	205.9	208.0	210.0	207.4	211.0	218.1	213.6	215.9	222.2	220.5	225.4	230.5	228.7	233.5	239.3	240.3	246.2
Jet Fuel 5/	124.4	177.4	201.9	175.2	157.3	149.4	146.7	140.4	150.6	149.9	147.3	149.7	151.8	151.7	154.2	160.9	159.6	162.7	168.6	167.8	171.9	177.4	177.4	181.7	187.5	189.5	193.8
Diesel Fuel (distillate fuel oil) 6/	187.1	241.3	272.0	267.5	247.1	234.6	230.0	219.8	226.7	225.0	218.7	220.8	224.7	223.1	224.6	232.3	230.1	233.0	239.8	235.5	241.2	249.2	245.6	250.1	260.8	259.8	267.1
Residual Fuel Oil	72.7	82.4	107.2	134.2	134.9	127.3	119.7	115.2	127.2	123.7	124.0	124.7	125.7	129.3	129.5	131.7	134.1	137.0	139.1	141.4	144.5	148.7	151.6	154.1	157.2	161.1	164.0
Residual Fuel Oil (2005 dollars per barrel)	30.51	34.82	45.03	56.35	56.67	53.48	50.29	48.39	53.43	51.93	52.10	52.36	52.79	54.30	54.37	55.31	56.31	57.55	58.42	59.38	60.68	62.44	63.68	64.71	66.04	67.67	68.89
Electric Power 7/																											
Distillate Fuel Oil	132.7	158.2	183.6	197.4	188.8	174.0	161.5	150.5	153.8	143.1	143.1	144.2	145.1	148.2	150.0	155.1	156.2	159.2	162.0	163.6	166.9	169.0	172.0	174.8	178.5	182.8	185.8
Residual Fuel Oil	75.6	105.5	117.5	109.0	109.8	103.0	97.5	91.9	140.4	125.6	132.5	141.3	146.6	151.2	153.7	163.7	165.8	173.8	176.0	179.6	183.6	190.2	193.9	199.1	203.0	207.9	211.3
Residual Fuel Oil (2005 dollars per barrel)	31.76	44.30	49.33	45.77	46.13	43.24	40.94	38.58	58.95	52.77	55.66	59.36	61.56	63.52	64.57	68.75	69.64	73.00	73.92	75.41	77.10	79.89	81.42	83.61	85.27	87.31	88.75
Refined Petroleum Product Prices 8/																											
Liquefied Petroleum Gases	109.3	150.7	167.7	163.2	162.8	158.5	156.4	153.8	153.7	152.4	151.8	152.1	153.1	154.0	154.1	154.1	154.2	154.4	155.1	156.1	156.9	157.9	158.9	160.3	160.7	160.9	161.0
Motor Gasoline 4/	195.0	231.1	262.1	263.0	240.1	223.6	217.4	208.4	216.0	214.8	205.9	208.0	210.0	207.3	210.9	218.0	213.5	215.8	222.1	220.5	225.4	230.5	228.7	233.4	239.2	240.2	246.1
Jet Fuel 5/	124.4	177.4	201.9	175.2	157.3	149.4	146.7	140.4	150.6	149.9	147.3	149.7	151.8	151.7	154.2	160.9	159.6	162.7	168.6	167.8	171.9	177.4	177.4	181.7	187.5	189.5	193.8
Distillate Fuel Oil	178.2	223.9	254.0	251.8	234.1	221.6	215.1	205.5	210.7	208.8	203.4	205.5	209.2	208.3	209.9	217.5	215.9	218.8	225.4	221.7	227.3	234.6	232.0	236.5	246.4	246.3	253.2
Residual Fuel Oil	76.7	99.4	118.5	125.2	125.9	118.7	112.3	106.6	128.9	122.1	124.1	126.1	127.4	130.9	131.5	134.7	136.9	140.2	142.3	143.9	147.0	150.3	153.1	155.6	158.6	161.6	164.5
Residual Fuel Oil (2005 dollars per barrel)	32.22	41.75	49.78	52.60	52.88	49.85	47.17	44.79	54.13	51.27	52.14	52.98	53.50	54.96	55.25	56.59	57.52	58.90	59.78	60.45	61.74	63.14	64.32	65.37	66.62	67.86	69.11
Average	168.5	204.4	232.6	230.6	212.5	200.9	194.9	186.8	194.7	193.1	187.5	189.3	191.6	190.5	193.1	199.5	197.0	199.4	205.1	203.6	208.0	213.2	212.1	216.3	222.4	223.4	228.7

1/ Weighted average price delivered to U.S. refiners.
2/ Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
3/ E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
4/ Sales weighted-average price for all grades. Includes Federal, State, and local taxes.
5/ Includes only kerosene type.
6/ Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
7/ Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
8/ Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
Sources: 2004 and 2005 imported low sulfur light crude oil price: Energy Information Administration (EIA), Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." 2004 and 2005 imported crude oil price: EIA, Annual Energy Review 2005, DOE/EIA-0384(2005) (Washington, DC, July 2006). 2004 and 2005 prices for motor gasoline, distillate fuel oil, and jet fuel are based on: EIA, Petroleum Marketing Annual 2005, DOE/EIA-0487(2005) (Washington, DC, August 2006). 2004 and 2005 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2004 and 2005 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2004 and 2005 ethanol prices "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2004 and 2005 ethanol prices derived from weekly spot prices in the Oxy Fuel News. 2004 and 2005 wholesale ethanol prices derived from Bloomburg U.S. average rack price. Projections: EIA, AEO2007 National Energy Modeling System run s280r4 d061507a.

HEARING EXHIBIT - 00000176

Table 12 Petroleum Product Prices
(2005 cents per gallon, unless otherwise noted)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Crude Oil Prices (2005 dollars per barrel)																											
Imported Low Sulfur Light Crude Oil	42.87	56.76	69.11	66.71	64.09	60.61	57.13	53.99	51.38	49.99	49.29	49.52	49.75	50.42	51.26	51.57	52.09	52.33	53.43	54.38	55.55	55.97	56.47	56.95	57.41	57.87	59.04
Imported Crude Oil 1/	37.09	49.19	61.35	59.49	57.23	54.21	51.20	48.48	46.22	45.01	44.41	44.61	44.81	45.22	45.64	46.05	46.47	47.08	47.71	48.33	48.94	49.57	49.97	50.40	50.80	51.21	51.63
Delivered Sector Product Prices																											
Residential																											
Liquefied Petroleum Gases	156.9	166.3	182.3	210.7	211.1	206.9	204.8	202.4	199.4	197.2	197.0	197.1	198.0	199.3	198.7	198.6	199.1	199.1	199.9	200.2	201.2	202.1	202.9	203.0	202.7	203.0	203.0
Distillate Fuel Oil	178.8	204.3	234.5	241.3	232.5	216.7	204.8	193.8	183.8	173.2	171.6	172.2	173.1	174.6	175.8	180.2	179.7	182.4	184.8	184.4	186.5	186.8	188.9	192.3	194.3	197.1	198.0
Commercial																											
Distillate Fuel Oil	145.0	175.4	202.3	209.7	196.9	183.1	174.2	165.0	155.3	148.9	145.1	145.8	147.9	148.2	149.6	154.7	153.4	156.2	160.5	157.8	161.2	165.3	164.4	169.7	174.0	175.3	178.9
Residual Fuel Oil	93.5	126.0	151.2	138.2	120.0	114.9	112.8	105.8	103.4	89.4	94.3	97.0	96.4	98.5	100.2	104.4	105.6	108.1	110.3	108.2	110.2	107.2	109.1	110.8	112.0	108.8	109.9
Residual Fuel Oil (2005 dollars per	39.29	52.90	63.50	49.66	50.40	48.25	47.39	44.43	43.42	37.56	39.63	40.76	40.50	41.37	42.09	43.66	44.37	45.40	46.34	45.43	46.30	45.01	45.84	46.55	47.04	45.70	46.18
Industrial 2/																											
Liquefied Petroleum Gases	96.3	146.2	163.4	150.3	149.9	144.8	142.4	139.3	139.8	138.2	138.0	138.1	139.2	140.4	140.4	141.0	141.5	141.5	141.9	141.7	142.6	143.8	144.7	145.3	145.4	145.8	146.1
Distillate Fuel Oil	152.2	181.1	209.6	211.9	194.6	182.7	177.0	171.9	176.1	173.8	169.0	170.3	173.9	173.0	175.5	182.8	181.6	184.4	188.5	183.7	187.0	195.1	193.7	201.8	209.2	210.7	218.1
Residual Fuel Oil	86.4	116.3	139.8	150.7	150.6	143.4	137.3	132.1	141.3	134.4	135.9	137.4	137.7	140.4	141.7	145.9	149.0	150.9	149.5	148.2	149.8	151.5	153.0	157.3	160.6	161.4	164.0
Residual Fuel Oil (2005 dollars per	36.30	48.86	58.73	63.28	63.26	60.23	57.65	55.49	59.35	56.45	57.07	57.73	57.81	58.97	59.53	61.29	62.58	63.37	62.77	62.23	62.93	63.61	64.25	66.06	67.45	67.80	68.89
Transportation																											
Liquefied Petroleum Gases	169.5	206.1	231.0	195.1	196.5	192.7	210.7	208.2	212.3	210.2	210.2	210.5	211.3	212.8	212.2	212.5	213.7	213.7	213.6	213.3	213.7	215.3	216.7	217.4	217.9	219.1	220.0
Ethanol (E85) 3/	198.4	219.2	235.4	274.6	257.1	242.6	234.8	226.9	220.6	212.3	208.2	203.7	200.5	198.4	197.3	200.8	200.4	199.1	201.6	198.8	200.6	203.9	203.2	203.0	206.5	207.0	211.0
Ethanol Wholesale Price	177.2	180.4	248.0	262.9	221.2	216.7	196.2	184.1	174.4	173.4	168.5	169.1	166.8	165.5	164.1	163.3	164.1	163.1	162.1	162.1	162.9	162.8	162.8	158.5	158.4	159.4	160.1
Motor Gasoline 4/	195.2	231.6	262.7	263.0	240.1	223.5	217.2	209.0	214.0	212.4	204.4	206.2	207.7	205.2	208.4	215.7	211.5	213.3	217.9	214.4	217.5	223.8	221.6	228.7	234.8	234.8	241.5
Jet Fuel 5/	124.4	177.4	201.9	175.0	157.3	149.4	146.6	140.4	148.0	147.5	145.3	146.9	148.5	148.3	151.0	157.9	156.7	159.5	163.4	160.8	162.9	168.1	169.4	176.7	181.1	184.1	189.1
Diesel Fuel (distillate fuel oil) 6	187.1	241.3	272.0	267.4	247.3	234.6	229.7	219.8	224.1	222.3	216.5	217.8	221.4	219.5	222.0	229.2	227.0	229.6	234.1	228.1	231.7	240.3	237.8	246.2	253.7	254.2	262.3
Residual Fuel Oil	72.7	82.4	107.2	134.1	134.9	127.2	119.6	115.0	123.9	120.5	121.3	121.5	121.6	124.9	125.0	127.8	130.8	132.6	131.9	131.8	133.3	137.5	140.2	145.3	148.8	154.9	157.8
Residual Fuel Oil (2005 dollars per	30.51	34.62	45.03	56.31	56.66	53.42	50.22	48.32	52.04	50.59	50.93	51.05	51.06	52.45	52.49	53.69	54.92	55.76	55.38	55.36	55.97	57.74	58.89	61.01	62.50	65.05	66.28
Electric Power 7/																											
Distillate Fuel Oil	132.7	158.2	183.6	197.3	188.5	173.8	161.7	150.4	151.2	141.1	140.5	141.1	142.1	144.6	146.5	151.8	153.2	155.7	156.1	156.0	157.5	160.0	163.2	168.7	172.3	177.6	179.7
Residual Fuel Oil	75.6	105.5	117.4	108.9	109.8	103.1	97.6	92.1	134.9	120.1	130.2	138.9	141.9	146.3	155.8	160.1	163.2	169.2	169.9	165.7	170.5	173.7	182.6	189.1	194.3	203.7	206.6
Residual Fuel Oil (2005 dollars per	31.76	44.30	49.33	45.75	46.12	43.31	41.01	38.70	56.64	50.46	54.69	58.33	59.61	61.47	65.44	67.26	68.54	71.07	71.36	69.60	71.62	72.93	76.69	79.42	81.59	85.57	86.78
Refined Petroleum Product Prices 8/																											
Liquefied Petroleum Gases	109.3	150.7	167.7	163.1	162.7	158.0	156.1	153.3	153.3	151.7	151.6	151.7	152.9	154.2	154.2	154.7	155.3	155.3	155.8	155.8	156.7	157.9	158.9	159.4	159.5	159.8	160.1
Motor Gasoline 4/	195.0	231.1	262.1	263.0	240.1	223.5	217.2	209.0	213.9	212.4	204.4	206.1	207.7	205.2	208.3	215.6	211.4	213.2	217.9	214.3	217.5	223.7	221.5	228.6	234.7	234.8	241.5
Jet Fuel 5/	124.4	177.4	201.9	175.0	157.3	149.4	146.6	140.4	148.0	147.5	145.3	146.9	148.5	148.3	151.0	157.9	156.7	159.5	163.4	160.8	162.9	168.1	169.4	176.7	181.1	184.1	189.1
Distillate Fuel Oil	178.2	223.9	254.0	251.7	234.2	221.5	214.8	205.5	208.4	206.6	201.6	202.9	206.4	205.3	207.7	214.8	213.1	215.9	220.4	215.4	218.9	226.8	225.1	233.1	240.4	241.5	249.0
Residual Fuel Oil	76.7	99.4	118.5	125.2	126.0	118.7	112.4	107.0	125.7	118.8	121.7	123.4	123.7	126.9	128.0	131.3	134.1	136.4	135.9	135.2	137.1	140.1	143.1	147.8	151.1	155.7	158.4
Residual Fuel Oil (2005 dollars per Average	32.22	41.75	49.78	52.57	52.93	49.87	47.20	44.95	52.78	49.91	51.13	51.83	51.94	53.29	53.76	55.15	56.31	57.30	57.07	56.77	57.56	58.84	60.09	62.07	63.47	65.38	66.55
	168.5	204.4	232.6	230.5	212.5	200.8	194.7	187.4	192.7	191.0	186.0	187.4	189.3	188.3	190.9	197.4	195.0	197.2	201.1	198.0	200.9	206.7	205.7	212.3	217.8	218.7	224.6

1/ Weighted average price delivered to U.S. refiners.
2/ Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
3/ E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
4/ Sales weighted-average price for all grades. Includes Federal, State, and local taxes.
5/ Includes only kerosene type.
6/ Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
7/ Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
8/ Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
Sources: 2004 and 2005 imported low sulfur light crude oil price: Energy Information Administration (EIA), Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." 2004 and 2005 imported crude oil price: EIA, Annual Energy Review 2005, DOE/EIA-0384(2005) (Washington, DC, July 2006). 2004 and 2005 prices for motor gasoline, distillate fuel oil, and jet fuel are based on: EIA, Petroleum Marketing Annual 2005, DOE/EIA-0487(2005) (Washington, DC, August 2006). 2004 and 2005 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2004 and 2005 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2004 and 2005 ethanol prices "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2004 and 2005 ethanol prices derived from weekly spot prices in the Oxy Fuel News. 2004 and 2005 wholesale ethanol prices derived from Bloomburg U.S. average rack price. Projections: EIA, AEO2007 National Energy Modeling System run s280vhioff25.d061607a.

LEADING EXHIBIT 00000000

Table 12 Petroleum Product Prices
(2005 cents per gallon unless otherwise noted)

Attachment POD-1 of Table 12 Petroleum Product Prices S 280 - High Auction Case

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Crude Oil Prices (2005 dollars per barrel)																											
Imported Low-Sulfur Light Crude Oil 1/	42.87	56.76	69.11	66.71	64.09	60.61	57.13	53.99	51.38	49.99	49.29	49.52	49.75	50.42	51.29	51.57	52.04	52.73	53.43	54.38	55.07	55.77	56.47	56.95	57.41	57.87	58.34
Imported Crude Oil 1/	37.09	49.19	61.75	59.49	57.23	54.21	51.20	48.48	46.22	45.01	44.41	44.61	44.81	45.22	45.64	46.05	46.47	47.08	47.71	48.33	48.94	49.57	49.97	50.40	50.80	51.21	51.63
Delivered Sector Product Prices																											
Residential																											
Liquefied Petroleum Gases	156.9	166.3	182.3	211.5	211.7	206.9	205.1	202.5	199.2	197.4	196.8	196.5	196.9	197.9	197.4	197.4	197.5	197.4	198.4	199.0	199.7	200.5	201.1	201.2	201.3	201.8	202.4
Distillate Fuel Oil	178.8	204.3	234.5	241.4	232.7	216.9	204.4	193.6	183.8	172.9	171.2	172.1	172.7	174.7	175.5	179.8	179.7	181.9	185.0	184.0	185.9	186.9	187.3	188.5	189.5	190.7	190.6
Commercial																											
Distillate Fuel Oil	145.0	175.4	202.3	209.7	197.0	183.2	174.0	164.9	155.3	148.8	144.7	146.0	148.2	148.2	149.1	153.7	153.4	155.6	160.8	157.3	160.8	164.2	162.6	164.5	169.2	167.7	171.3
Residual Fuel Oil	93.5	126.0	151.2	118.3	120.0	114.8	112.8	105.8	103.3	89.4	94.4	97.1	96.5	98.5	100.2	104.5	105.7	108.1	110.4	108.2	110.2	107.1	109.1	110.5	111.6	108.2	109.2
Residual Fuel Oil (2005 dollars per barrel)	39.29	52.90	63.50	49.67	50.40	48.21	47.39	44.44	43.40	37.56	39.65	40.77	40.51	41.37	42.10	43.88	44.38	45.42	46.35	45.44	46.29	45.00	45.83	46.43	46.86	45.42	45.87
Industrial 2/																											
Liquefied Petroleum Gases	96.3	146.2	163.4	150.9	150.4	144.8	142.6	139.4	139.5	138.3	137.6	137.4	138.4	139.7	140.0	140.8	140.9	141.4	142.6	143.8	145.2	146.7	147.6	148.5	149.4	150.6	152.2
Distillate Fuel Oil	152.2	181.1	209.6	212.0	194.7	182.8	176.9	171.9	176.1	173.7	168.3	170.8	175.7	175.1	177.4	184.5	184.8	188.8	197.2	194.2	200.9	208.5	208.3	213.8	224.1	223.8	233.6
Residual Fuel Oil	86.4	116.3	139.8	150.6	148.5	143.3	137.2	132.2	140.9	134.2	135.8	137.7	139.1	142.9	145.1	149.7	153.0	156.9	159.8	161.3	165.5	169.2	172.5	176.6	181.2	184.6	190.8
Residual Fuel Oil (2005 dollars per barrel)	36.30	48.86	58.73	63.27	62.35	60.19	57.62	55.53	59.19	56.37	57.02	57.82	58.42	60.03	60.92	62.89	64.25	65.88	67.10	67.75	69.51	71.08	72.47	74.19	76.11	77.55	80.12
Transportation																											
Liquefied Petroleum Gases	169.5	206.1	231.0	195.9	197.1	192.7	210.9	208.4	211.9	210.3	210.0	210.0	210.8	212.4	212.3	212.9	213.9	214.6	216.6	218.2	219.9	222.0	223.9	225.5	227.2	229.4	231.8
Ethanol (E85) 3/	198.4	219.2	235.4	274.1	258.0	242.6	234.8	226.8	220.7	210.9	209.0	201.9	202.8	196.5	199.5	200.5	199.1	200.2	203.7	203.2	204.3	208.6	207.8	210.7	213.9	215.2	222.1
Ethanol Wholesale Price	177.2	180.4	248.0	262.5	221.5	216.8	196.0	184.1	174.4	168.9	168.9	166.3	166.4	162.3	164.0	162.6	162.3	161.2	158.9	158.4	157.6	157.2	155.3	154.9	153.0	153.5	154.2
Motor Gasoline 4/	195.2	231.6	262.7	262.5	240.4	223.5	217.3	209.0	214.1	212.1	204.7	205.4	208.8	206.8	210.5	217.6	213.9	217.0	224.2	223.2	228.1	234.4	234.3	239.9	246.8	247.9	256.1
Jet Fuel 5/	124.4	177.4	201.9	175.1	157.4	149.6	146.5	140.3	148.1	147.3	144.6	146.9	149.4	150.1	153.2	159.7	159.6	163.7	170.6	170.3	175.7	182.5	183.8	189.1	194.8	196.6	204.2
Diesel Fuel (distillate fuel oil) 6/	187.1	241.3	272.0	267.2	247.3	234.7	229.7	219.8	224.0	222.3	215.7	218.2	223.3	221.6	223.7	230.7	230.1	233.9	242.5	238.4	245.4	253.3	252.1	257.4	268.6	267.1	277.6
Residual Fuel Oil	72.7	82.4	107.2	134.2	134.8	127.2	119.6	115.1	123.7	120.3	121.0	121.7	122.9	127.3	128.2	131.4	135.0	138.7	141.9	146.2	150.2	155.8	160.8	164.7	169.1	174.6	180.1
Residual Fuel Oil (2005 dollars per barrel)	30.51	34.62	45.03	56.35	56.60	53.40	50.22	48.35	51.96	50.52	50.82	51.12	51.63	53.45	53.84	55.17	56.69	58.26	59.61	61.41	63.09	65.42	67.55	69.19	71.03	73.33	75.64
Electric Power 7/																											
Distillate Fuel Oil	132.7	158.2	183.6	197.4	188.6	173.9	161.5	150.2	150.8	140.7	140.3	141.4	142.7	146.7	149.1	154.2	156.3	160.0	164.6	167.0	171.3	175.4	179.1	183.3	187.7	192.0	196.7
Residual Fuel Oil	75.6	105.5	117.5	109.0	109.7	103.8	97.7	92.2	137.0	119.5	127.5	135.6	141.2	145.4	151.5	160.7	165.4	174.3	177.4	183.5	192.6	199.6	207.2	220.9	224.8	231.1	237.0
Residual Fuel Oil (2005 dollars per barrel)	31.76	44.30	49.33	45.79	46.06	43.58	41.03	38.72	57.55	50.18	53.56	56.97	59.29	61.08	63.61	67.50	69.48	73.20	74.50	77.06	80.88	83.81	87.03	92.80	94.43	97.06	99.53
Refined Petroleum Product Prices 8/																											
Liquefied Petroleum Gases	109.3	150.7	167.7	163.7	163.3	158.0	156.4	153.4	153.0	151.8	151.2	151.1	152.1	153.3	153.6	154.3	154.5	154.9	156.1	157.2	158.6	160.0	160.9	161.7	162.5	163.5	165.0
Motor Gasoline 4/	195.0	231.1	262.1	262.5	240.4	223.5	217.2	209.0	214.1	212.0	204.6	205.4	208.7	206.8	210.4	217.5	213.8	216.9	224.1	223.1	228.0	234.4	234.2	239.8	246.7	247.8	256.0
Jet Fuel 5/	124.4	177.4	201.9	175.1	157.4	149.6	146.5	140.3	148.1	147.3	144.6	146.9	149.4	150.1	153.2	159.7	159.6	163.7	170.6	170.3	175.7	182.5	183.8	189.1	194.8	196.6	204.2
Distillate Fuel Oil	178.2	223.9	254.0	251.6	234.3	221.5	214.8	205.4	208.3	206.5	200.9	203.3	207.9	207.0	209.2	216.0	215.8	219.6	227.8	224.4	231.0	238.4	237.8	242.9	253.2	252.4	262.1
Residual Fuel Oil	76.7	99.4	118.5	125.3	125.7	119.2	112.5	107.2	125.7	118.6	121.2	123.2	124.7	128.7	130.3	134.3	137.7	141.7	144.8	148.1	152.2	156.7	161.5	165.5	169.6	173.8	179.1
Residual Fuel Oil (2005 dollars per barrel)	32.22	41.75	49.78	52.61	52.79	50.05	47.26	45.00	52.81	49.81	50.89	51.73	52.36	54.06	54.74	56.41	57.84	59.51	60.80	62.22	63.93	65.80	67.82	69.52	71.21	73.00	75.21
Average	168.5	204.4	232.6	230.4	212.8	200.9	194.8	187.3	192.8	190.8	185.8	187.1	190.2	189.7	192.5	198.8	197.2	200.4	207.0	206.0	211.0	217.0	217.3	222.2	229.0	229.9	237.6

1/ Weighted average price delivered to U.S. refiners.
2/ Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
3/ E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
4/ Sales weighted-average price for all grades. Includes Federal, State, and local taxes.
5/ Includes only kerosene type.
6/ Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
7/ Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
8/ Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
Sources: 2004 and 2005 imported low sulfur light crude oil price: Energy Information Administration (EIA), Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." 2004 and 2005 imported crude oil price: EIA, Annual Energy Review 2005, DOE/EIA-0384(2005) (Washington, DC, July 2006). 2004 and 2005 prices for motor gasoline, distillate fuel oil, and jet fuel are based on: EIA, Petroleum Marketing Annual 2005, DOE/EIA-0487(2005) (Washington, DC, August 2006). 2004 and 2005 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2004 and 2005 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2004 and 2005 ethanol prices "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2004 and 2005 ethanol prices derived from weekly spot prices in the Oxy Fuel News. 2004 and 2005 wholesale ethanol prices derived from Bloomburg U.S. average rack price. Projections: EIA, AEO2007 National Energy Modeling System run s280cc70 d060207a.

HEARING EXHIBIT - 00000181

Table 12 Petroleum Product Prices
(2005 cents per gallon, unless otherwise noted)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Crude Oil Prices (2005 dollars per barrel)																											
Imported Low-Sulfur Light Crude Oil 1/	42.87	56.76	69.11	66.71	64.09	60.61	57.13	53.99	51.38	49.99	49.29	49.84	49.75	50.42	50.90	51.57	52.04	52.73	53.43	54.38	55.07	55.77	56.47	56.95	57.41	57.87	58.34
Imported Crude Oil 1/	37.09	49.19	61.75	59.49	57.23	54.21	51.20	48.48	46.22	45.01	44.41	44.61	44.81	45.22	45.64	46.05	46.47	47.08	47.71	48.33	48.94	49.57	49.97	50.40	50.80	51.21	51.63
Delivered Sector Product Prices																											
Residential																											
Liquefied Petroleum Gases	156.9	166.3	182.3	210.9	211.1	207.1	205.1	202.4	199.2	197.0	196.7	196.4	197.1	198.5	198.1	197.7	197.3	197.7	198.9	199.9	200.2	200.7	201.4	201.5	201.7	201.4	202.2
Distillate Fuel Oil	178.8	204.3	234.5	241.3	232.4	217.0	204.6	193.8	183.6	172.4	171.3	172.3	172.8	174.5	175.8	180.1	179.9	182.2	184.9	184.0	185.8	186.1	187.5	189.1	190.3	191.3	191.5
Commercial																											
Distillate Fuel Oil	145.0	175.4	202.3	209.8	196.9	183.3	174.1	164.9	158.2	162.3	159.5	161.1	163.8	165.3	167.9	174.4	175.2	179.1	185.6	183.8	190.2	195.8	197.0	202.0	209.9	212.1	218.9
Residual Fuel Oil	93.5	126.0	151.2	118.2	119.4	114.9	112.8	105.8	118.6	105.5	111.2	114.6	114.9	118.5	121.8	127.7	130.8	135.2	139.7	139.8	144.4	144.1	149.0	153.6	158.1	158.4	163.6
Residual Fuel Oil (2005 dollars per barrel)	39.29	52.90	63.50	49.66	50.16	48.25	47.40	44.43	49.81	44.33	46.70	48.12	48.28	49.76	51.14	53.64	54.92	56.80	58.66	58.73	60.65	60.51	62.59	64.53	66.41	66.54	68.72
Industrial 2/																											
Liquefied Petroleum Gases	96.3	146.2	163.4	150.4	149.9	145.0	142.7	139.3	139.5	137.9	137.5	137.4	138.5	140.0	140.4	140.8	140.6	141.4	142.9	144.3	145.4	146.5	147.7	148.6	149.6	150.0	151.8
Distillate Fuel Oil	152.2	181.1	209.6	211.9	194.6	183.0	176.9	171.7	175.8	173.6	168.8	170.9	174.7	174.6	177.1	184.9	184.2	188.2	195.6	192.1	200.0	207.8	207.4	213.0	223.6	223.9	233.2
Residual Fuel Oil	86.4	116.3	139.8	150.7	148.0	143.4	137.3	132.1	140.7	134.1	135.5	137.2	138.3	142.1	144.0	148.5	151.7	155.5	158.5	160.0	164.2	167.7	171.1	175.1	179.4	182.8	195.9
Residual Fuel Oil (2005 dollars per barrel)	36.30	48.86	58.73	63.28	62.16	60.23	57.66	55.50	59.09	56.30	56.91	57.61	58.10	59.69	60.49	62.39	63.71	65.29	66.57	67.20	68.95	70.44	71.85	73.53	75.34	76.76	82.28
Transportation																											
Liquefied Petroleum Gases	169.5	206.1	231.0	195.4	196.5	192.9	211.0	208.3	212.0	209.9	209.9	209.7	210.6	212.6	212.7	212.7	213.3	214.5	216.5	218.6	219.9	221.6	223.5	225.1	226.8	228.1	230.7
Ethanol (E85) 3/	198.4	219.2	235.4	274.6	257.9	242.8	235.1	226.3	220.6	212.4	207.6	202.5	200.7	198.2	198.5	200.0	198.6	202.4	202.5	202.8	204.3	207.5	207.9	210.0	212.5	215.1	219.4
Ethanol Wholesale Price	177.2	180.4	248.0	262.9	221.3	217.0	196.0	184.6	174.4	173.4	168.0	166.5	166.8	163.7	164.1	162.6	162.4	162.1	159.9	158.4	157.5	157.7	155.4	155.0	154.0	153.7	154.0
Motor Gasoline 4/	195.2	231.6	262.7	263.0	240.2	223.7	217.6	208.5	214.0	212.4	204.2	205.6	208.0	205.8	210.1	217.4	213.2	216.5	223.6	222.4	227.6	233.8	233.3	238.6	246.2	248.3	255.1
Jet Fuel 5/	124.4	177.4	201.9	175.1	157.4	149.7	146.5	140.2	147.9	147.2	144.7	146.9	148.8	149.6	153.0	159.9	159.2	163.2	170.2	169.7	175.1	181.6	182.7	188.3	194.4	196.3	203.8
Diesel Fuel (distillate fuel oil) 6/	187.1	241.3	272.0	267.4	247.3	234.8	229.6	219.6	223.8	222.2	216.2	218.4	222.3	221.0	223.6	231.3	229.6	233.3	241.1	236.3	244.5	252.6	251.2	256.8	268.2	267.2	277.4
Residual Fuel Oil	72.7	82.4	107.2	134.1	134.7	127.2	119.6	115.0	123.5	120.2	120.8	121.0	122.2	126.5	127.3	130.3	133.8	137.5	140.7	144.4	148.7	154.4	159.5	162.9	167.2	172.2	178.3
Residual Fuel Oil (2005 dollars per barrel)	30.51	34.62	45.03	56.32	56.59	53.44	50.25	48.31	51.89	50.50	50.75	50.82	51.34	53.15	53.45	54.73	56.18	57.75	59.08	60.65	62.45	64.83	66.97	68.43	70.24	72.31	74.87
Electric Power 7/																											
Distillate Fuel Oil	132.7	158.2	183.6	197.3	188.7	174.2	161.7	150.3	150.6	140.4	140.3	141.0	142.3	146.2	148.6	153.8	155.8	159.6	163.1	165.7	170.1	173.9	177.6	181.6	186.2	190.7	194.7
Residual Fuel Oil	75.6	105.5	117.5	108.9	109.5	103.8	97.8	92.1	136.1	119.1	127.8	131.4	136.1	144.3	150.7	161.0	166.5	174.6	177.5	182.8	188.7	199.2	206.5	214.8	222.3	227.8	234.3
Residual Fuel Oil (2005 dollars per barrel)	31.76	44.30	49.33	45.76	46.01	43.59	41.06	38.68	57.15	50.00	53.66	55.20	57.18	60.62	63.29	67.62	69.91	73.32	74.55	76.78	79.27	83.66	86.74	90.22	93.39	95.69	98.42
Refined Petroleum Product Prices 8/																											
Liquefied Petroleum Gases	109.3	150.7	167.7	163.2	162.7	158.2	156.4	153.3	153.2	151.6	151.4	151.3	152.4	154.0	154.4	154.7	154.6	155.4	156.9	158.3	159.4	160.4	161.6	162.4	163.4	163.7	165.4
Motor Gasoline 4/	195.0	231.1	262.1	262.9	240.2	223.7	217.6	208.5	213.9	212.4	204.2	205.5	208.0	205.8	210.1	217.4	213.2	216.5	223.6	222.4	227.6	233.8	233.3	238.6	246.2	248.3	255.1
Jet Fuel 5/	124.4	177.4	201.9	175.1	157.4	149.7	146.5	140.2	147.9	147.2	144.7	146.9	148.8	149.6	153.0	159.9	159.2	163.2	170.2	169.7	175.1	181.6	182.7	188.3	194.4	196.3	203.8
Distillate Fuel Oil	178.2	223.9	254.0	251.7	234.2	221.7	214.8	205.3	208.7	207.1	202.1	204.1	207.8	207.3	209.9	217.5	216.3	220.2	227.7	223.8	231.5	239.1	238.5	243.9	254.6	254.5	263.9
Residual Fuel Oil	76.7	99.4	118.5	125.2	125.5	119.2	112.6	107.0	127.1	120.3	122.8	124.0	125.6	130.2	131.9	136.0	139.5	143.7	146.9	150.2	154.6	159.6	164.8	168.6	173.1	177.4	184.5
Residual Fuel Oil (2005 dollars per barrel)	32.22	41.75	49.78	52.58	52.72	50.07	47.28	44.94	53.40	50.51	51.60	52.09	52.75	54.68	55.40	57.12	58.60	60.34	61.71	63.07	64.93	67.05	69.20	70.82	72.71	74.52	77.47
Average	168.5	204.4	232.6	230.5	212.6	201.1	194.9	186.9	192.9	191.2	186.0	187.4	189.8	189.3	192.7	199.2	197.0	200.4	206.8	205.7	211.0	216.9	217.0	222.0	229.2	230.8	237.7

1/ Weighted average price delivered to U.S. refiners.
2/ Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
3/ E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
4/ Sales weighted-average price for all grades. Includes Federal, State, and local taxes.
5/ Includes only kerosene type.
6/ Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
7/ Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
8/ Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
Sources: 2004 and 2005 imported low sulfur light crude oil price: Energy Information Administration (EIA), Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." 2004 and 2005 imported crude oil price: EIA, Annual Energy Review 2005, DOE/EIA-0384(2005) (Washington, DC, July 2006). 2004 and 2005 prices for motor gasoline, distillate fuel oil, and jet fuel are based on: EIA, Petroleum Marketing Annual 2005, DOE/EIA-0487(2005) (Washington, DC, August 2006). 2004 and 2005 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2004 and 2005 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2004 and 2005 ethanol prices "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2004 and 2005 ethanol prices derived from weekly spot prices in the Oxy Fuel News. 2004 and 2005 wholesale ethanol prices derived from Bloomburg U.S. average rack price. Projections: EIA, AEO2007 National Energy Modeling System run s280comm d061507a.

HEARING EXHIBIT 2008-0010

Table 12 Petroleum Product Prices
(2005 cents per gallon, unless otherwise noted)

Attachment POD-1 of Table 12 Petroleum Product Prices S.280 - High Technology Case

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Crude Oil Prices (2005 dollars per barrel)																											
Imported Low-Sulfur Light Crude Oil 1/	42.87	56.76	69.11	66.71	64.09	60.61	57.13	53.99	51.70	50.33	49.62	49.84	50.09	50.77	51.31	51.57	52.04	52.73	53.43	54.38	55.07	55.77	56.47	57.52	58.07	58.60	59.12
Imported Crude Oil 1/	37.09	49.19	61.75	59.49	57.23	54.21	51.20	48.48	46.22	45.01	44.41	44.61	44.81	45.22	45.64	46.05	46.47	47.08	47.71	48.33	48.94	49.57	49.97	50.40	50.80	51.21	51.63
Delivered Sector Product Prices																											
Residential																											
Liquefied Petroleum Gases	156.9	166.3	182.3	210.3	210.0	205.4	202.2	199.4	197.3	196.0	196.0	195.9	197.0	198.4	198.4	197.8	198.3	198.5	200.1	200.7	201.8	202.3	203.6	204.2	204.2	204.7	204.2
Distillate Fuel Oil	178.8	204.3	234.5	241.2	231.5	215.8	203.5	191.5	183.2	169.9	169.7	170.5	171.2	173.0	174.4	178.1	178.9	180.3	183.9	182.6	184.3	184.5	184.2	185.2	185.3	187.8	188.4
Commercial																											
Distillate Fuel Oil	145.0	175.4	202.3	209.6	196.1	182.5	173.1	162.4	153.7	145.4	143.0	144.5	146.6	146.3	148.1	152.3	151.2	153.6	158.3	154.7	157.3	160.1	157.4	159.5	163.1	163.6	166.2
Residual Fuel Oil	93.5	126.0	151.2	118.2	118.0	114.9	112.7	105.5	103.6	89.6	94.6	97.2	96.5	98.7	100.4	104.6	105.8	108.2	110.5	108.3	110.3	107.3	109.3	110.7	111.8	108.3	109.5
Residual Fuel Oil (2005 dollars per barrel)	39.29	52.90	63.50	49.65	49.54	48.24	47.34	44.32	43.51	37.61	39.73	40.84	40.55	41.46	42.15	43.91	44.42	45.45	46.41	45.48	46.35	45.08	45.89	46.51	46.94	45.50	45.97
Industrial 2/																											
Liquefied Petroleum Gases	96.3	146.2	163.4	149.7	148.7	143.2	139.7	136.5	134.3	133.4	133.1	133.0	134.2	135.5	135.9	135.7	135.8	136.1	137.4	138.0	139.1	139.5	140.5	141.2	141.2	141.5	140.8
Distillate Fuel Oil	152.2	181.1	209.6	211.8	194.2	182.5	176.3	169.2	160.5	155.9	152.0	154.0	157.5	155.3	157.3	162.5	159.8	162.5	167.2	162.5	165.4	169.7	166.4	169.3	175.1	174.3	178.3
Residual Fuel Oil	86.4	116.3	139.8	150.4	149.5	143.2	136.9	130.6	127.0	118.9	120.0	120.8	120.6	123.3	123.8	126.1	127.6	129.1	130.9	131.0	132.6	132.6	134.1	135.0	139.3	133.5	135.3
Residual Fuel Oil (2005 dollars per barrel)	36.30	48.86	58.73	63.16	62.77	60.13	57.49	54.84	53.34	49.94	50.40	50.72	50.64	51.77	52.00	52.95	53.59	54.23	54.97	55.03	55.68	55.70	56.31	56.68	58.51	56.07	56.81
Transportation																											
Liquefied Petroleum Gases	169.5	206.1	231.0	194.7	195.2	191.1	208.0	205.3	203.1	201.5	201.5	201.3	202.1	203.5	203.2	202.3	202.7	202.8	204.2	204.8	205.8	206.2	207.4	207.9	207.8	208.2	207.7
Ethanol (E85) 3/	198.4	219.2	235.4	274.6	252.5	238.2	231.6	215.7	211.0	198.5	198.8	194.6	190.6	187.6	190.6	192.5	190.1	193.6	191.7	192.4	193.4	194.1	194.9	193.3	195.0	197.9	198.6
Ethanol Wholesale Price	177.2	180.4	248.0	263.0	223.6	216.2	211.3	186.2	180.6	171.5	172.1	171.4	169.8	167.8	168.7	168.8	169.7	169.9	168.2	168.5	169.5	169.0	169.8	164.8	165.7	167.6	168.2
Motor Gasoline 4/	195.2	231.6	262.7	263.0	240.0	224.9	218.1	205.1	200.5	197.0	190.8	191.5	192.3	189.3	192.1	197.5	194.7	195.9	200.4	198.1	200.3	203.0	202.6	205.8	210.6	211.2	213.7
Jet Fuel 5/	124.4	177.4	201.9	175.0	156.8	149.2	145.5	138.0	133.8	132.5	129.1	131.2	132.9	131.7	133.6	137.1	136.7	137.7	141.6	140.0	141.1	143.4	142.0	144.2	146.6	148.0	150.3
Diesel Fuel (distillate fuel oil) 6/	187.1	241.3	272.0	267.2	246.6	234.3	229.6	217.1	208.1	204.2	199.5	201.4	205.1	202.1	203.9	208.8	205.2	207.8	212.5	206.6	209.7	214.3	210.5	213.4	220.0	218.4	222.3
Residual Fuel Oil	72.7	82.4	107.2	134.1	134.0	126.3	119.3	113.3	109.0	105.4	104.9	104.2	104.1	107.3	106.9	107.9	109.8	112.2	114.0	115.4	117.1	119.2	120.4	121.5	122.6	124.3	124.8
Residual Fuel Oil (2005 dollars per barrel)	30.51	34.62	45.03	56.32	56.28	53.03	50.09	47.59	45.78	44.25	44.07	43.77	43.74	45.08	44.90	45.30	46.13	47.11	47.87	48.48	49.19	50.07	50.57	51.02	51.50	52.19	52.42
Electric Power 7/																											
Distillate Fuel Oil	132.7	158.2	183.6	197.2	188.2	173.5	159.9	147.9	137.9	125.8	124.8	125.8	126.0	128.0	129.2	132.6	134.0	135.2	138.0	138.0	139.7	140.1	139.5	140.5	140.7	142.7	144.3
Residual Fuel Oil	75.6	105.5	117.5	108.8	108.9	103.5	98.1	92.5	88.0	81.6	82.5	83.8	83.9	85.7	86.7	89.4	89.8	93.0	95.5	94.5	96.2	97.3	97.6	98.6	99.9	100.1	101.1
Residual Fuel Oil (2005 dollars per barrel)	31.76	44.30	49.33	45.71	45.72	43.46	41.19	38.86	36.98	34.27	34.67	35.18	35.22	36.00	36.41	37.54	37.72	39.05	40.11	39.70	40.40	40.87	41.01	41.42	41.94	42.05	42.45
Refined Petroleum Product Prices 8/																											
Liquefied Petroleum Gases	109.3	150.7	167.7	162.6	161.6	156.6	153.7	150.7	148.7	147.8	147.7	147.7	149.0	150.4	150.8	150.6	150.9	151.2	152.6	153.2	154.4	154.7	155.9	156.6	156.6	156.9	156.2
Motor Gasoline 4/	195.0	231.1	262.1	262.9	240.0	224.9	218.1	205.1	200.5	197.0	190.8	191.5	192.2	189.2	192.1	197.5	194.7	195.9	200.4	198.1	200.3	203.0	202.6	205.8	210.6	211.2	213.7
Jet Fuel 5/	124.4	177.4	201.9	175.0	156.8	149.2	145.5	138.0	133.8	132.5	129.1	131.2	132.9	131.7	133.6	137.1	136.7	137.7	141.6	140.0	141.1	143.4	142.0	144.2	146.6	148.0	150.3
Distillate Fuel Oil	178.2	223.9	254.0	251.5	233.6	221.2	214.5	202.9	194.9	190.7	186.8	188.7	192.1	190.0	191.9	196.8	194.0	196.6	201.5	196.3	199.3	203.7	200.2	203.1	209.1	208.2	212.0
Residual Fuel Oil	76.7	99.4	118.5	125.1	125.0	118.7	112.7	106.8	102.3	96.2	96.9	97.4	97.3	99.8	100.2	102.2	103.4	106.0	108.1	108.2	109.9	111.1	111.9	113.0	114.4	114.5	115.4
Residual Fuel Oil (2005 dollars per barrel)	32.22	41.75	49.78	52.54	52.49	49.84	47.34	44.84	42.96	40.39	40.71	40.91	40.86	41.93	42.09	42.93	43.44	44.52	45.39	45.45	46.17	46.65	47.02	47.44	48.05	48.08	48.45
Average	168.5	204.4	232.6	230.5	212.4	201.3	195.0	184.6	179.6	176.4	172.3	173.5	175.0	173.3	175.6	180.1	178.4	180.1	184.3	182.0	184.2	186.7	185.9	188.8	193.0	193.4	195.9

1/ Weighted average price delivered to U.S. refiners.
2/ Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
3/ E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
4/ Sales weighted-average price for all grades. Includes Federal, State, and local taxes.
5/ Includes only kerosene type.
6/ Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
7/ Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
8/ Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
Sources: 2004 and 2005 imported low sulfur light crude oil price: Energy Information Administration (EIA), Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." 2004 and 2005 imported crude oil price: EIA, Annual Energy Review 2005, DOE/EIA-0384(2005) (Washington, DC, July 2006). 2004 and 2005 prices for motor gasoline, distillate fuel oil, and jet fuel are based on: EIA, Petroleum Marketing Annual 2005, DOE/EIA-0487(2005) (Washington, DC, August 2006). 2004 and 2005 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2004 and 2005 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2004 and 2005 ethanol prices "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2004 and 2005 ethanol prices derived from weekly spot prices in the Oxy Fuel News. 2004 and 2005 wholesale ethanol prices derived from Bloomburg U.S. average rack price. Projections: EIA, AEO2007 National Energy Modeling System run htrkiten.d060107a.

HEARING EXHIBIT - 00000182

Table 12 Petroleum Product Prices
(2005 cents per gallon, unless otherwise noted)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Crude Oil Prices (2005 dollars per barrel)																											
Imported Low-Sulfur Light Crude O	42.87	56.76	69.11	66.71	64.09	60.61	57.13	53.99	51.38	49.99	49.29	49.52	49.75	50.42	50.90	51.57	52.04	52.73	53.43	54.38	55.07	55.77	56.47	56.55	57.41	57.87	58.34
Imported Crude Oil 1/	37.09	49.19	61.75	59.49	57.23	54.21	51.20	48.48	46.22	45.01	44.41	44.61	44.81	45.22	45.64	46.05	46.47	47.08	47.71	48.33	48.94	49.57	49.97	50.40	50.80	51.21	51.63
Delivered Sector Product Prices																											
Residential																											
Liquefied Petroleum Gases	156.9	166.3	182.3	210.7	211.5	207.6	205.2	202.8	199.2	197.2	198.7	197.8	198.4	200.0	199.4	199.7	199.9	199.8	201.5	202.9	203.6	202.3	204.5	205.7	206.0	207.5	207.9
Distillate Fuel Oil	178.8	204.3	234.5	241.3	232.7	217.0	204.5	193.6	183.8	172.9	172.0	172.5	173.0	174.9	175.9	179.9	179.8	182.1	184.9	184.0	185.2	186.2	187.4	188.6	190.1	191.6	192.7
Commercial																											
Distillate Fuel Oil	145.0	175.4	202.3	209.7	197.0	183.4	174.1	165.0	155.3	148.8	145.2	146.1	148.3	148.1	149.5	154.1	153.6	156.1	160.7	156.7	160.6	164.7	162.9	165.8	170.2	170.1	173.2
Residual Fuel Oil	93.5	126.0	151.2	118.2	120.0	114.9	112.9	105.8	103.4	89.4	94.4	97.0	96.4	98.5	100.2	104.4	105.7	108.1	110.3	108.2	110.2	107.2	109.1	110.6	111.6	108.2	109.4
Residual Fuel Oil (2005 dollars p	39.29	52.90	63.50	49.66	50.40	48.25	47.41	44.45	43.42	37.55	39.67	40.74	40.50	41.37	42.10	43.87	44.38	45.40	46.35	45.43	46.29	45.00	45.83	46.44	46.86	45.44	45.93
Industrial 2/																											
Liquefied Petroleum Gases	96.3	146.2	163.4	150.2	150.3	145.4	142.8	139.6	139.8	138.4	139.9	139.3	140.5	142.5	142.9	143.7	144.2	144.6	146.8	148.6	150.0	149.3	152.1	154.1	155.5	157.5	158.8
Distillate Fuel Oil	152.2	181.1	209.6	211.9	194.7	183.1	177.2	172.1	176.9	174.6	169.7	172.3	177.3	176.6	179.8	187.1	187.3	192.0	199.7	196.2	204.3	213.3	212.3	219.4	229.4	231.6	240.2
Residual Fuel Oil	86.4	116.3	139.8	150.7	148.0	143.4	137.5	132.4	142.3	135.1	137.4	138.9	140.9	145.0	147.4	152.1	155.6	159.6	162.6	164.9	169.4	173.8	177.5	181.4	186.4	190.2	195.9
Residual Fuel Oil (2005 dollars p	36.30	48.86	58.73	63.28	62.16	60.22	57.74	55.62	59.78	56.73	57.73	58.33	59.17	60.90	61.91	63.86	65.35	67.02	68.30	69.24	71.16	73.00	74.56	76.17	78.27	79.88	82.28
Transportation																											
Liquefied Petroleum Gases	169.5	206.1	231.0	195.1	196.9	193.4	211.1	208.6	212.5	210.6	212.4	212.1	213.1	215.3	215.3	216.2	217.4	218.3	221.1	223.6	225.5	225.6	229.2	232.1	234.1	237.6	240.0
Ethanol (E85) 3/	198.4	219.2	235.4	274.6	258.4	243.2	235.6	226.6	220.9	211.6	207.9	204.9	203.2	201.4	199.3	202.5	202.0	202.8	205.1	204.3	207.1	210.0	210.7	212.4	216.0	217.1	222.6
Ethanol Wholesale Price	177.2	180.4	248.0	262.8	221.3	217.1	195.4	184.2	175.1	173.3	169.2	167.4	165.4	165.4	164.0	162.6	161.6	161.0	158.5	157.4	157.2	156.7	155.5	153.5	153.2	151.6	151.2
Motor Gasoline 4/	195.2	231.6	262.7	263.0	240.5	223.8	217.7	208.5	214.6	213.1	205.4	207.0	209.9	207.6	211.4	218.5	215.8	219.5	226.9	225.4	230.6	237.4	237.4	242.8	250.6	253.3	259.9
Jet Fuel 5/	124.4	177.4	201.9	175.0	157.5	149.8	146.7	140.5	148.7	148.1	145.9	148.7	151.2	151.8	155.4	162.1	162.1	166.7	173.4	173.5	179.1	185.7	187.5	192.9	200.0	204.1	210.4
Diesel Fuel (distillate fuel oil)	187.1	241.3	272.0	267.4	247.4	234.8	229.9	219.9	224.8	223.1	217.0	219.6	224.7	223.0	226.2	233.3	232.6	237.2	245.0	240.3	248.8	258.3	256.1	263.1	274.0	275.3	284.2
Residual Fuel Oil	72.7	82.4	107.2	134.1	134.8	127.2	119.8	115.2	124.9	121.2	122.5	122.7	124.7	129.4	130.8	133.9	137.5	141.5	145.4	149.1	153.9	159.7	164.8	169.6	173.7	183.6	187.4
Residual Fuel Oil (2005 dollars p	30.51	34.62	45.03	56.31	56.62	53.42	50.30	48.37	52.45	50.91	51.45	51.54	52.37	54.36	54.93	56.24	57.75	59.44	61.07	62.64	64.65	67.08	69.21	71.25	72.93	77.10	78.71
Electric Power 7/																											
Distillate Fuel Oil	132.7	158.2	183.6	197.3	188.7	174.0	161.6	150.3	151.9	141.5	141.7	143.1	144.9	148.6	151.5	156.9	159.0	163.0	167.2	170.1	174.6	178.5	182.8	187.2	191.9	197.7	202.7
Residual Fuel Oil	75.6	105.5	117.4	108.9	109.7	103.1	97.8	92.1	134.8	117.0	123.6	137.6	142.6	148.8	156.7	165.2	167.1	174.6	178.4	182.8	187.8	196.0	207.0	210.8	214.7	228.5	239.0
Residual Fuel Oil (2005 dollars p	31.76	44.30	49.33	45.75	46.07	43.31	41.07	38.67	56.60	49.13	51.92	57.80	59.87	62.48	65.81	69.39	70.17	73.34	74.91	76.77	78.86	82.31	86.94	88.55	90.18	95.95	100.37
Refined Petroleum Product Prices 8/																											
Liquefied Petroleum Gases	109.3	150.7	167.7	163.0	163.1	158.6	156.5	153.6	153.2	151.8	153.4	152.9	154.1	156.0	156.3	157.1	157.6	158.0	160.1	161.9	163.2	162.5	165.1	167.0	168.2	170.2	171.4
Motor Gasoline 4/	195.0	231.1	262.1	262.9	240.5	223.8	217.7	208.5	214.5	213.1	205.3	207.0	209.9	207.4	211.3	218.5	215.7	219.4	226.8	225.3	230.5	237.3	237.4	242.7	250.5	253.2	259.8
Jet Fuel 5/	124.4	177.4	201.9	175.0	157.5	149.8	146.7	140.5	148.7	148.1	145.9	148.7	151.2	151.8	155.4	162.1	162.1	166.7	173.4	173.5	179.1	185.7	187.5	192.9	200.0	204.1	210.4
Distillate Fuel Oil	178.2	223.9	254.0	251.7	234.3	221.7	215.0	205.6	209.0	207.3	202.2	204.6	209.2	208.3	211.3	218.3	218.0	222.5	230.0	226.0	233.8	242.5	241.2	247.9	257.9	259.7	268.2
Residual Fuel Oil	76.7	99.4	118.5	125.2	125.7	118.8	112.5	106.9	126.4	118.8	121.7	124.2	126.2	130.6	132.9	136.7	140.0	144.1	147.7	150.7	155.2	160.0	164.9	169.3	173.1	181.1	185.2
Residual Fuel Oil (2005 dollars p	32.22	41.75	49.78	52.57	52.79	49.88	47.26	44.91	53.09	49.89	51.13	52.17	53.01	54.92	55.81	57.43	58.78	60.51	62.03	63.27	65.20	67.18	69.27	71.10	72.69	76.08	77.77
Average	168.5	204.4	232.6	230.5	212.8	201.1	195.0	187.0	193.3	191.6	186.8	188.6	191.5	190.7	194.1	200.4	199.3	203.1	209.7	208.4	213.8	220.2	220.5	225.9	233.2	236.0	242.4

1/ Weighted average price delivered to U.S. refiners.
2/ Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
3/ E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
4/ Sales weighted-average price for all grades. Includes Federal, State, and local taxes.
5/ Includes only kerosene type.
6/ Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
7/ Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
8/ Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
Sources: 2004 and 2005 imported low sulfur light crude oil price: Energy Information Administration (EIA), Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." 2004 and 2005 imported crude oil price: EIA, Annual Energy Review 2005, DOE/EIA-0384(2005) (Washington, DC, July 2006). 2004 and 2005 prices for motor gasoline, distillate fuel oil, and jet fuel are based on: EIA, Petroleum Marketing Annual 2005, DOE/EIA-0487(2005) (Washington, DC, August 2006). 2004 and 2005 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2004 and 2005 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2004 and 2005 ethanol prices "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2004 and 2005 ethanol prices derived from weekly spot prices in the Oxy Fuel News. 2004 and 2005 wholesale ethanol prices derived from Bloomburg U.S. average rack price. Projections: EIA, AEO2007 National Energy Modeling System run s280nucbio.d092807a.

HEARING EXHIBIT - 00000184

Table 12 Petroleum Product Prices
(2005 cents per gallon, unless otherwise noted)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Crude Oil Prices (2005 dollars per barrel)																											
Imported Low-Sulfur Light Crude Oil 1/	42.87	56.76	69.11	66.71	64.09	60.61	57.13	53.99	51.38	49.99	49.29	49.52	49.75	50.42	51.30	51.57	52.04	52.73	53.43	54.38	55.07	55.77	56.47	56.95	57.41	57.87	58.34
Imported Crude Oil 1/	37.09	49.19	61.75	59.49	57.23	54.21	51.20	48.48	46.22	45.01	44.41	44.61	44.81	45.22	45.64	46.05	46.47	47.08	47.71	48.33	48.94	49.57	49.97	50.40	50.80	51.21	51.63
Delivered Sector Product Prices																											
Residential																											
Liquefied Petroleum Gases	156.9	166.3	182.3	210.7	211.3	207.3	205.2	202.5	199.1	197.2	197.2	199.8	199.8	201.1	201.1	201.1	200.7	201.0	202.6	204.4	205.9	206.3	207.5	208.9	210.1	211.4	211.8
Distillate Fuel Oil	178.8	204.3	234.5	241.3	232.4	216.8	204.1	194.0	183.9	173.1	171.5	172.5	173.5	174.9	175.9	179.1	179.8	182.0	184.9	183.9	185.2	185.8	187.1	188.2	189.6	190.9	191.4
Commercial																											
Distillate Fuel Oil	145.0	175.4	202.3	209.7	196.9	183.3	174.1	165.1	155.3	148.9	144.9	146.0	147.7	147.7	149.6	152.9	153.6	155.9	160.7	156.6	160.3	164.0	162.5	166.2	170.0	170.1	172.5
Residual Fuel Oil	93.5	126.0	151.2	118.2	119.6	114.8	112.8	105.8	103.4	89.4	94.4	97.0	96.4	98.5	100.3	104.4	105.7	108.1	110.4	108.2	110.2	107.2	109.1	110.6	111.6	108.2	109.3
Residual Fuel Oil (2005 dollars per barrel)	39.29	52.90	63.50	49.66	50.22	48.22	47.39	44.45	43.41	37.56	39.65	40.75	40.50	41.38	42.12	43.85	44.39	45.41	46.35	45.43	46.30	45.00	45.84	46.45	46.89	45.44	45.91
Industrial 2/																											
Liquefied Petroleum Gases	96.3	146.2	163.4	150.2	150.0	145.2	142.8	139.5	140.1	138.9	139.1	142.2	142.7	144.3	145.3	146.0	145.8	146.7	148.8	151.4	153.9	154.8	156.9	159.3	161.7	164.1	165.3
Distillate Fuel Oil	152.2	181.1	209.6	211.9	194.7	183.1	177.3	171.9	178.2	176.5	171.8	174.8	178.7	178.8	183.1	189.1	191.1	195.8	204.0	200.7	209.0	217.8	217.8	226.8	236.6	239.5	247.9
Residual Fuel Oil	86.4	116.3	139.8	150.7	148.1	143.5	137.3	132.4	143.5	137.4	139.9	142.1	144.1	148.5	151.4	155.8	159.9	164.2	167.7	170.7	175.5	180.2	185.1	189.8	194.5	199.0	207.7
Residual Fuel Oil (2005 dollars per barrel)	36.30	48.86	58.73	63.28	62.21	60.27	57.65	55.59	60.26	57.69	58.76	59.66	60.52	62.39	63.59	65.45	67.14	68.97	70.44	71.71	73.73	75.67	77.75	79.73	81.69	83.58	87.25
Transportation																											
Liquefied Petroleum Gases	169.5	206.1	231.0	195.1	196.7	193.1	211.1	208.4	213.0	211.5	212.2	215.4	216.0	216.0	218.7	219.5	220.2	221.6	224.4	227.6	230.5	232.5	235.5	238.8	242.0	245.4	248.3
Ethanol (E85) 3/	198.4	219.2	235.4	274.6	258.6	243.6	236.1	227.3	216.5	213.9	207.7	207.6	197.8	200.5	201.9	203.5	202.2	204.6	206.5	206.8	208.5	212.6	211.6	217.4	220.2	217.3	218.3
Ethanol Wholesale Price	177.2	180.4	248.0	262.9	220.6	216.7	195.7	183.3	174.8	173.3	166.4	168.6	163.0	164.7	163.9	162.5	161.1	160.5	158.3	156.9	156.1	155.5	152.5	153.1	151.5	145.9	144.9
Motor Gasoline 4/	195.2	231.6	262.7	263.0	240.2	223.7	217.6	208.4	215.3	214.6	207.0	211.2	212.1	210.1	214.1	220.4	218.9	222.8	229.9	229.1	234.1	240.6	241.2	248.0	255.9	259.0	264.6
Jet Fuel 5/	124.4	177.4	201.9	175.1	157.4	149.6	146.6	140.4	150.0	149.9	148.2	151.2	153.8	154.5	158.5	164.1	165.6	170.4	177.1	177.1	183.7	189.9	192.3	199.0	206.4	210.7	216.7
Diesel Fuel (distillate fuel oil) 6/	187.1	241.3	272.0	267.3	247.2	234.7	230.3	219.7	226.1	225.2	219.2	222.2	226.0	225.1	229.6	235.3	236.4	241.0	249.3	244.7	253.4	262.6	261.4	270.8	281.2	283.3	292.1
Residual Fuel Oil	72.7	82.4	107.2	134.1	134.7	127.2	119.5	115.0	126.2	123.2	125.0	125.6	127.8	132.9	134.6	138.0	141.9	146.3	150.7	154.9	160.0	166.0	171.2	177.3	185.0	192.7	198.1
Residual Fuel Oil (2005 dollars per barrel)	30.51	34.62	45.03	56.31	56.57	53.44	50.21	48.32	53.01	51.75	52.50	52.74	53.69	55.83	56.54	57.96	59.62	61.46	63.29	65.07	67.21	69.71	71.92	74.46	77.71	80.94	83.20
Electric Power 7/																											
Distillate Fuel Oil	132.7	158.2	183.6	197.3	188.5	174.0	161.3	150.4	153.0	143.5	143.6	145.6	148.0	151.7	154.8	159.3	162.9	167.2	172.0	175.0	179.6	184.0	188.9	193.6	199.0	205.0	210.0
Residual Fuel Oil	75.6	105.5	117.6	108.9	109.6	103.2	97.5	92.0	134.9	118.5	128.1	134.3	144.7	152.2	159.1	167.2	169.2	175.8	182.6	187.6	193.3	199.6	206.2	214.1	224.3	233.9	238.6
Residual Fuel Oil (2005 dollars per barrel)	31.76	44.30	49.39	45.75	46.01	43.32	40.93	38.63	56.64	49.77	53.80	56.39	60.76	63.92	66.84	70.20	71.06	73.85	76.71	78.79	81.17	83.85	86.60	89.92	94.19	98.26	100.23
Refined Petroleum Product Prices 8/																											
Liquefied Petroleum Gases	109.3	150.7	167.7	163.0	162.9	158.4	156.6	153.5	153.5	152.2	152.5	155.5	156.1	157.7	158.6	159.2	159.0	159.9	162.0	164.4	166.8	167.6	169.6	171.8	174.0	176.1	177.3
Motor Gasoline 4/	195.0	231.1	262.1	263.0	240.2	223.7	217.6	208.4	215.2	214.5	206.9	211.1	212.0	210.0	214.0	220.4	218.8	222.7	229.8	229.0	234.0	240.5	241.1	247.9	255.8	258.9	264.5
Jet Fuel 5/	124.4	177.4	201.9	175.1	157.4	149.6	146.6	140.4	150.0	149.9	148.2	151.2	153.8	154.5	158.5	164.1	165.6	170.4	177.1	177.1	183.7	189.9	192.3	199.0	206.4	210.7	216.7
Distillate Fuel Oil	178.2	223.9	254.0	251.7	234.2	221.6	215.2	205.5	210.2	209.0	203.9	206.7	210.4	210.1	214.2	219.9	221.3	225.6	233.7	229.8	237.8	246.3	245.8	254.4	264.0	266.4	274.5
Residual Fuel Oil	76.7	99.4	118.6	125.2	125.5	118.8	112.2	106.6	127.4	120.5	124.3	126.1	128.9	133.9	136.2	140.2	143.7	148.1	152.3	155.8	160.7	165.5	170.5	176.1	183.0	189.2	194.6
Residual Fuel Oil (2005 dollars per barrel)	32.22	41.75	49.80	52.57	52.73	49.90	47.13	44.78	53.51	50.62	52.20	52.96	54.16	56.23	57.21	58.89	60.37	62.21	63.98	65.43	67.47	69.49	71.62	73.96	76.86	79.45	81.72
Average	168.5	204.4	232.6	230.5	212.6	201.0	195.0	186.8	194.1	192.9	188.2	191.7	193.4	192.9	196.6	202.1	202.2	206.2	212.8	212.0	217.5	223.7	224.5	231.2	238.7	241.8	247.7

1/ Weighted average price delivered to U.S. refiners.
2/ Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
3/ E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
4/ Sales weighted-average price for all grades. Includes Federal, State, and local taxes.
5/ Includes only kerosene type.
6/ Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
7/ Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
8/ Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
Sources: 2004 and 2005 imported low sulfur light crude oil price: Energy Information Administration (EIA), Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." 2004 and 2005 imported crude oil price: EIA, Annual Energy Review 2005, DOE/EIA-0384(2005) (Washington, DC, July 2006). 2004 and 2005 prices for motor gasoline, distillate fuel oil, and jet fuel are based on: EIA, Petroleum Marketing Annual 2005, DOE/EIA-0487(2005) (Washington, DC, August 2006). 2004 and 2005 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2004 and 2005 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2004 and 2005 ethanol prices "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2004 and 2005 ethanol prices derived from weekly spot prices in the Oxy Fuel News. 2004 and 2005 wholesale ethanol prices derived from Bloomburg U.S. average rack price. Projections: EIA, AEO2007 National Energy Modeling System run s280ccs d092807a.

HEARING EXHIBIT

Table 12. Petroleum Product Prices
(2005 cents per gallon, unless otherwise noted)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Crude Oil Prices (2005 dollars per barrel)																											
Imported Low-Sulfur Light Crude Oil 1/	42.87	56.76	69.11	66.71	64.09	60.61	57.13	53.99	51.38	49.99	49.29	49.52	49.75	50.42	51.30	51.57	52.04	52.73	53.43	54.38	55.07	55.77	56.47	56.95	57.41	57.87	58.34
Imported Crude Oil 1/	37.09	49.19	61.75	59.49	57.23	54.21	51.20	48.48	46.22	45.01	44.41	44.61	44.81	45.22	45.64	46.05	46.47	47.08	47.71	48.33	48.94	49.57	49.97	50.40	50.80	51.21	51.63
Delivered Sector Product Prices																											
Residential																											
Liquefied Petroleum Gases	156.9	166.3	182.3	210.9	211.3	207.1	205.5	203.2	199.5	197.0	200.2	199.4	199.6	201.1	200.8	200.7	200.8	202.2	203.5	205.3	206.8	207.4	209.4	210.9	211.7	212.8	215.1
Distillate Fuel Oil	178.8	204.3	234.5	241.4	232.4	216.8	204.7	194.0	183.9	172.9	172.1	172.1	173.2	174.8	175.8	178.6	179.7	182.0	184.9	183.8	185.2	185.2	186.9	188.0	189.4	190.4	190.7
Commercial																											
Distillate Fuel Oil	145.0	175.4	202.3	209.8	196.9	183.2	174.4	165.2	155.3	148.7	145.3	145.8	148.0	147.6	149.3	152.7	153.3	155.9	160.6	156.8	160.4	163.8	162.4	165.4	169.4	169.6	170.8
Residual Fuel Oil	93.5	126.0	151.2	118.3	120.0	114.9	112.9	105.8	103.4	89.4	94.4	97.0	96.4	98.5	100.3	104.4	105.7	108.1	110.4	108.2	110.2	107.2	109.2	110.6	111.7	108.2	109.3
Residual Fuel Oil (2005 dollars per barrel)	39.29	52.90	63.50	49.67	50.40	48.26	47.41	44.45	43.41	37.56	39.66	40.74	40.50	41.39	42.11	43.87	44.38	45.42	46.35	45.44	46.30	45.01	45.85	46.46	46.91	45.46	45.93
Industrial 2/																											
Liquefied Petroleum Gases	96.3	146.2	163.4	150.4	150.0	145.1	143.2	140.2	140.6	138.9	142.5	141.9	142.7	144.4	145.0	145.8	146.0	148.1	150.1	152.4	154.9	156.0	159.2	161.7	163.5	165.8	169.7
Distillate Fuel Oil	152.2	181.1	209.6	212.0	194.7	183.0	177.3	172.1	178.3	176.4	172.3	174.8	179.5	179.1	183.0	189.3	190.9	196.1	204.4	201.5	209.6	218.3	218.1	226.2	236.2	239.8	246.1
Residual Fuel Oil	86.4	116.3	139.8	150.7	148.0	143.5	137.5	132.5	144.0	137.6	140.5	142.1	144.4	148.8	151.6	156.3	160.0	164.6	168.3	171.1	176.3	180.7	186.4	190.0	196.6	199.9	206.0
Residual Fuel Oil (2005 dollars per barrel)	36.30	48.86	58.73	63.31	62.16	60.28	57.75	55.64	60.46	57.80	59.00	59.69	60.65	62.51	63.69	65.63	67.21	69.13	70.67	71.87	74.03	75.88	78.27	79.80	82.56	83.95	86.50
Transportation																											
Liquefied Petroleum Gases	169.5	206.1	231.0	195.3	196.7	192.8	211.4	209.1	213.4	211.4	215.1	214.9	215.9	218.1	218.5	219.3	220.5	223.0	225.5	228.7	231.7	233.8	237.6	241.0	243.8	247.1	251.8
Ethanol (E85) 3/	198.4	219.2	235.4	274.6	258.7	243.7	236.4	227.3	213.6	214.2	210.0	202.5	199.0	199.6	201.3	204.1	202.8	205.4	206.8	207.0	209.0	213.8	212.1	217.5	220.0	218.0	220.7
Ethanol Wholesale Price	177.2	180.4	248.0	262.8	220.8	216.7	195.8	184.0	174.8	173.3	168.8	166.0	162.1	162.8	163.4	162.5	161.1	159.7	158.3	157.1	156.6	156.1	152.8	153.1	151.5	146.4	144.5
Motor Gasoline 4/	195.2	231.6	262.7	263.0	240.2	223.7	217.8	208.4	215.6	214.9	207.4	209.9	212.0	209.8	213.7	220.1	218.8	223.1	230.7	229.7	234.9	241.7	241.4	248.5	256.0	259.0	266.2
Jet Fuel 5/	124.4	177.4	201.9	175.2	157.4	149.6	146.7	140.5	150.1	150.1	148.3	151.2	153.9	154.7	158.5	164.1	165.8	170.4	177.5	177.9	184.1	190.3	192.6	198.9	206.4	210.8	216.3
Diesel Fuel (distillate fuel oil) 6/	187.1	241.3	272.0	267.5	247.4	234.6	230.1	219.8	226.2	225.0	219.7	222.0	226.9	225.4	229.2	235.7	236.2	241.2	249.7	245.5	254.0	263.1	261.7	270.1	280.5	283.7	289.9
Residual Fuel Oil	72.7	82.4	107.2	134.2	134.8	127.3	119.7	115.1	126.5	123.7	125.9	125.9	128.1	133.2	135.0	138.4	142.0	146.8	151.0	155.4	160.5	167.2	172.0	177.9	185.2	193.5	198.1
Residual Fuel Oil (2005 dollars per barrel)	30.51	34.62	45.03	56.34	56.62	53.46	50.29	48.34	53.12	51.95	52.88	52.88	53.81	55.96	56.71	58.14	59.66	61.64	63.40	65.27	67.42	70.22	72.26	74.73	77.79	81.25	83.19
Electric Power 7/																											
Distillate Fuel Oil	132.7	158.2	183.6	197.4	188.7	174.1	161.8	150.7	153.4	143.6	144.5	146.0	148.2	151.4	154.6	159.3	163.1	167.5	172.3	175.5	180.1	184.2	189.3	194.0	199.5	205.0	210.0
Residual Fuel Oil	75.6	105.5	117.7	109.0	109.7	103.0	97.1	91.9	137.2	120.7	133.3	136.6	148.7	156.9	162.0	168.0	169.7	177.1	183.4	186.8	194.3	201.4	207.3	213.4	219.1	229.0	236.5
Residual Fuel Oil (2005 dollars per barrel)	31.76	44.30	49.43	45.77	46.07	43.27	40.80	38.61	57.62	50.69	55.99	57.37	62.46	65.90	68.05	70.55	71.28	74.37	77.03	78.45	81.60	84.59	87.07	89.62	92.04	96.18	99.34
Refined Petroleum Product Prices 8/																											
Liquefied Petroleum Gases	109.3	150.7	167.7	163.2	162.9	158.3	156.9	154.2	153.9	152.2	155.7	155.3	156.0	157.7	158.3	159.0	159.3	161.2	163.2	165.4	167.8	168.9	171.8	174.1	175.8	177.8	181.3
Motor Gasoline 4/	195.0	231.1	262.1	263.0	240.2	223.7	217.8	208.4	215.5	214.8	207.4	209.8	211.9	209.8	213.6	220.0	218.7	223.1	230.6	229.6	234.8	241.6	241.3	248.4	255.9	258.9	266.0
Jet Fuel 5/	124.4	177.4	201.9	175.2	157.4	149.6	146.7	140.5	150.1	150.1	148.3	151.2	153.9	154.7	158.5	164.1	165.8	170.4	177.5	177.9	184.1	190.3	192.6	198.9	206.4	210.8	216.3
Distillate Fuel Oil	178.2	223.9	254.0	251.8	234.3	221.5	215.2	205.6	210.2	208.8	204.5	206.6	211.1	210.3	214.0	220.1	221.0	226.0	234.0	230.5	238.4	246.7	246.0	253.7	263.5	266.6	272.5
Residual Fuel Oil	76.7	99.4	118.6	125.2	125.7	118.7	111.9	108.6	127.9	121.2	125.7	126.6	129.6	134.6	136.8	140.6	143.9	148.6	152.7	156.1	161.2	166.5	171.4	176.5	183.0	189.5	194.2
Residual Fuel Oil (2005 dollars per barrel)	32.22	41.75	49.82	52.60	52.78	49.87	47.00	44.78	53.74	50.92	52.80	53.18	54.42	56.52	57.44	59.06	60.42	62.40	64.12	65.57	67.70	69.93	71.97	74.14	76.87	79.60	81.58
Average	168.5	204.4	232.6	230.6	212.6	200.9	195.0	186.9	194.3	193.1	188.8	191.0	193.6	192.9	196.4	201.9	202.2	206.6	213.4	212.6	218.2	224.4	224.9	231.4	238.7	241.9	248.2

1/ Weighted average price delivered to U.S. refiners.
2/ Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
3/ E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
4/ Sales weighted-average price for all grades. Includes Federal, State, and local taxes.
5/ Includes only kerosene type.
6/ Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
7/ Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
8/ Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
Sources: 2004 and 2005 imported low sulfur light crude oil price: Energy Information Administration (EIA), Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." 2004 and 2005 imported crude oil price: EIA, Annual Energy Review 2005, DOE/EIA-0384(2005) (Washington, DC, July 2006). 2004 and 2005 prices for motor gasoline, distillate fuel oil, and jet fuel are based on: EIA, Petroleum Marketing Annual 2005, DOE/EIA-0487(2005) (Washington, DC, August 2006). 2004 and 2005 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2004 and 2005 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2004 and 2005 ethanol prices "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2004 and 2005 ethanol prices derived from weekly spot prices in the Oxy Fuel News. 2004 and 2005 wholesale ethanol prices derived from Bloomburg U.S. average rack price. Projections: EIA, AEO2007 National Energy Modeling System run s280gas.d100107a.

HEARING EXHIBIT - 20080196

Attachment POD-1.g. Table 15 Coal Supply, Disposition, and Prices

Cases:

Reference
Core S.280
No International S.280
Fixed 30% Offset S.280
No Nuclear S.280
Low Discount S.280
Unlimited Offset S.280
High Auction S.280
Commercial Covered S.280
High Technology S.280
Ref NB S.280
Ref NB+noCCS S.280
Ref NBLNG+noCCS S.280

HEARING EXHIBIT 2014-07

Table 15. Coal Supply, Disposition, and Prices
(million short tons, unless otherwise noted)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2005-2030
Production 1/																												
Appalachia	391	397	394	379	377	380	381	378	377	378	375	371	363	357	342	343	348	348	348	348	348	351	357	361	365	366	373	-0.3%
Interior	146	149	149	153	154	157	171	178	184	187	192	199	199	197	200	203	203	207	205	209	212	215	222	226	236	244	247	2.0%
West	575	585	605	611	613	622	637	658	664	673	693	697	710	724	738	750	772	803	847	875	906	951	984	1004	1027	1049	1072	2.5%
East of the Mississippi	485	494	494	479	481	487	498	500	505	508	509	507	499	493	479	482	487	488	486	491	493	499	511	520	530	534	545	0.4%
West of the Mississippi	627	638	655	664	663	672	691	714	721	729	751	759	773	786	801	815	837	869	913	941	973	1018	1051	1071	1098	1124	1146	2.4%
Total	1112	1131	1149	1143	1145	1159	1189	1214	1225	1237	1260	1266	1272	1279	1280	1296	1323	1358	1399	1432	1466	1517	1563	1591	1628	1658	1691	1.6%
Waste Coal Supplied 2/	11	13	14	16	16	18	13	14	14	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	0.0%
Net Imports																												
Imports 3/	26	29	32	37	37	37	37	37	37	38	40	42	50	57	70	71	72	71	73	74	79	79	79	82	85	91	95	4.9%
Exports	48	50	46	48	46	44	44	44	43	43	41	37	35	33	31	30	31	31	30	28	26	27	27	27	27	27	27	-2.4%
Total	-22	-21	-14	-11	-9	-7	-7	-7	-6	-5	-1	5	14	24	39	41	41	39	43	45	53	52	52	55	58	64	68	N/A
Total Supply 4/	1101	1124	1149	1148	1152	1169	1195	1222	1234	1246	1272	1284	1299	1316	1331	1351	1377	1410	1454	1489	1532	1582	1628	1659	1699	1735	1772	1.8%
Consumption by Sector																												
Residential and Commercial	5	5	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	-0.3%
Coke Plants	24	23	24	23	22	22	22	22	22	22	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	-0.5%
Other Industrial 5/	62	61	64	62	63	64	64	64	64	63	63	62	62	62	62	63	63	63	63	63	63	63	64	64	64	64	64	0.2%
Coal-to-Liquids Heat and Power	0	0	0	0	0	0	0	5	6	6	8	8	8	9	11	12	13	15	22	23	30	42	49	49	53	55	57	N/A
Coal to Liquids Production	0	0	0	0	0	0	0	5	5	5	8	8	8	9	10	12	13	14	21	22	29	40	48	48	51	53	55	N/A
Electric Power 6/	1016	1039	1043	1058	1061	1079	1104	1121	1132	1145	1168	1178	1195	1209	1222	1239	1262	1292	1323	1356	1384	1411	1442	1472	1505	1538	1570	1.7%
Total	1107	1128	1135	1147	1152	1169	1195	1222	1233	1245	1272	1282	1299	1315	1331	1350	1377	1409	1454	1489	1532	1582	1628	1659	1699	1735	1772	1.8%
Discrepancy and Stock Change 7/	-6	-5	14	0	0	0	0	0	0	0	0	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	N/A
Average Minemouth Price 8/																												
(2005 dollars per short ton)	20.68	23.34	24.02	24.11	23.93	23.73	24.20	23.54	23.12	22.92	22.63	22.41	22.11	21.91	21.54	21.51	21.58	21.63	21.48	21.43	21.48	21.55	21.75	21.97	22.24	22.36	22.60	-0.1%
(2005 dollars per million Btu)	1.01	1.15	1.17	1.18	1.17	1.16	1.18	1.16	1.14	1.13	1.12	1.11	1.10	1.09	1.08	1.08	1.08	1.09	1.08	1.08	1.09	1.09	1.10	1.11	1.13	1.13	1.15	0.0%
Delivered Prices																												
(2005 dollars per short ton) 9/																												
Coke Plants	83.36	83.79	89.27	90.44	90.16	87.46	84.86	82.04	79.34	76.50	75.17	74.51	74.22	74.22	74.17	73.77	74.25	74.55	74.57	74.23	73.66	73.93	74.19	74.51	74.89	75.18	75.55	-0.4%
Other Industrial 5/	40.49	47.63	47.32	48.42	48.52	48.32	48.86	48.02	47.65	47.62	47.61	47.45	47.28	47.21	47.00	46.71	46.55	46.84	47.05	47.13	47.34	47.60	47.71	47.84	48.21	48.32	48.54	0.1%
Coal to Liquids	N/A	N/A	N/A	N/A	N/A	N/A	N/A	13.81	13.68	13.73	13.83	13.79	13.86	14.04	14.19	14.82	15.05	15.70	15.78	15.84	17.74	19.82	20.90	21.00	22.15	21.99	21.89	N/A
Electric Power																												
(2005 dollars per short ton)	28.12	30.83	33.59	33.84	34.06	33.96	34.17	33.29	32.69	32.32	32.13	31.84	31.65	31.60	31.29	31.33	31.39	31.46	31.60	31.66	31.93	32.20	32.42	32.67	32.97	33.15	33.52	0.3%
(2005 dollars per million Btu)	1.40	1.53	1.67	1.69	1.70	1.70	1.71	1.67	1.64	1.62	1.61	1.60	1.59	1.59	1.58	1.58	1.58	1.59	1.60	1.60	1.61	1.63	1.64	1.65	1.67	1.67	1.69	0.4%
Average	29.58	32.82	35.55	35.75	35.96	35.76	35.89	34.78	34.12	33.70	33.41	33.10	32.89	32.78	32.43	32.41	32.42	32.46	32.42	32.43	32.58	32.72	32.87	33.10	33.40	33.52	33.82	0.1%
Exports 10/	55.75	67.10	67.31	69.48	70.64	69.99	69.35	68.27	66.88	65.55	64.85	64.51	65.42	65.45	64.78	63.78	64.49	64.60	64.03	62.87	61.18	61.66	61.98	62.36	62.85	63.26	63.81	-0.2%

1/ Includes anthracite, bituminous coal, subbituminous coal, and lignite.
2/ Includes waste coal consumed by the electric power and industrial sectors. Waste coal supplied is counted as a supply-side item to balance the same amount of waste coal included in the consumption data.
3/ Excludes imports to Puerto Rico and the U.S. Virgin Islands.
4/ Production plus waste coal supplied plus net imports.
5/ Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public. Excludes all coal in the coal-to-liquids process.
6/ Includes all electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
7/ Balancing item: the sum of production, net imports, and waste coal supplied minus total consumption.
8/ Includes reported prices for both open market and captive mines.
9/ Prices weighted by consumption; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
10/ F.a.s. price at U.S. port of exit.
N/A = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
Sources: 2004 and 2005 data based on: Energy Information Administration (EIA), Annual Coal Report 2005, DOE/EIA-0584(2005) (Washington, DC, October 2006); EIA, Quarterly Coal Report, October-December 2005, DOE/EIA-0121(2005/4Q) (Washington, DC, March 2006); and EIA, AEO2007 National Energy Modeling System run aeo2007.d112106a.
Projections: EIA, AEO2007 National Energy Modeling System run aeo2007.d112106a.

HEARING EXHIBIT - 00000188

Table 15. Coal Supply, Disposition, and Prices
(million short tons, unless otherwise noted)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Production 1/																											
Appalachia	391	397	393	379	366	365	355	345	343	335	328	326	321	312	295	284	277	269	268	266	260	253	247	245	232	210	195
Interior	146	149	145	148	149	152	166	168	170	170	171	175	165	160	153	151	147	139	145	133	138	147	136	145	147	137	126
West	575	585	609	620	598	590	587	586	604	598	597	585	578	578	565	553	544	530	512	516	494	466	450	400	337	296	265
East of the Mississippi	485	494	490	478	466	467	467	460	461	453	444	445	434	422	401	387	378	367	371	362	358	359	346	351	340	310	290
West of the Mississippi	627	638	657	668	648	640	640	639	657	650	652	641	631	628	612	601	589	572	554	554	534	507	487	439	377	333	296
Total	1112	1131	1147	1147	1114	1107	1107	1099	1118	1104	1096	1086	1065	1049	1013	988	967	938	925	916	891	866	833	790	716	643	586
Waste Coal Supplied 2/	11	13	14	14	16	17	9	14	13	13	13	13	13	13	13	13	12	10	4	4	5	7	9	8	7	6	6
Net Imports																											
Imports 3/	26	29	32	37	37	37	37	37	37	38	40	47	48	54	69	77	76	70	70	61	55	48	39	37	36	35	34
Exports	48	50	49	53	52	51	50	49	48	47	46	44	43	40	44	45	46	46	46	45	45	45	45	45	45	44	44
Total	-22	-21	-16	-16	-15	-14	-13	-12	-11	-9	-6	2	5	14	25	32	30	25	24	15	10	3	-6	-7	-9	-10	-10
Total Supply 4/	1101	1124	1145	1145	1115	1109	1103	1101	1120	1108	1103	1101	1083	1077	1051	1033	1010	973	953	934	906	877	836	790	714	640	581
Consumption by Sector																											
Residential and Commercial	5	5	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Coke Plants	24	23	24	23	22	22	22	22	21	21	21	21	21	20	20	20	20	20	19	19	19	19	19	19	19	19	19
Other Industrial 5/	62	61	64	62	63	63	63	64	61	59	59	59	58	58	58	57	57	57	57	57	57	56	57	57	57	56	56
Coal-to-Liquids Heat and Power	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Coal to Liquids Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Electric Power 6/	1016	1039	1039	1056	1024	1019	1014	1011	1033	1022	1017	1016	998	993	967	949	927	890	870	853	824	794	754	707	634	559	503
Total	1107	1128	1131	1145	1114	1109	1103	1101	1119	1107	1102	1100	1082	1076	1049	1031	1009	971	951	933	904	875	835	788	715	638	582
Discrepancy and Stock Change 7/	-6	-5	14	0	0	0	0	0	1	1	1	1	1	1	2	2	1	2	2	1	1	2	1	3	0	2	-1
Average Minemouth Price 8/																											
(2005 dollars per short ton)	20.68	23.34	24.03	24.03	23.68	23.54	23.40	22.86	22.53	22.12	21.87	21.84	21.89	21.60	21.50	21.27	21.28	21.22	21.48	21.27	21.45	21.66	21.54	22.33	23.26	23.38	23.51
(2005 dollars per million Btu)	1.01	1.15	1.17	1.18	1.16	1.15	1.15	1.12	1.11	1.09	1.08	1.08	1.08	1.06	1.06	1.05	1.05	1.04	1.05	1.04	1.05	1.06	1.05	1.08	1.11	1.12	1.11
Delivered Prices																											
(2005 dollars per short ton) 9/																											
Coke Plants	63.36	83.79	89.37	91.13	90.54	87.67	84.89	82.13	119.14	117.26	118.99	120.06	123.13	126.45	139.20	143.40	147.86	154.33	159.70	165.32	171.31	177.74	184.71	192.18	200.37	209.09	218.65
Other Industrial 5/	40.49	47.63	47.15	48.29	48.06	47.90	47.90	46.82	73.32	74.80	75.61	76.77	79.11	81.46	84.10	86.95	90.02	93.37	97.29	101.33	105.79	110.47	114.14	119.48	125.28	131.11	138.70
Coal to Liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electric Power																											
(2005 dollars per short ton)	28.12	30.83	33.68	33.93	33.72	33.47	33.22	32.28	56.92	57.48	58.21	59.23	61.61	63.79	66.23	68.69	71.68	74.90	78.83	82.30	86.27	90.53	94.72	100.52	107.31	113.04	119.70
(2005 dollars per million Btu)	1.40	1.53	1.68	1.70	1.69	1.68	1.66	1.62	2.86	2.89	2.93	2.98	3.09	3.20	3.32	3.45	3.59	3.75	3.93	4.11	4.31	4.52	4.74	4.99	5.27	5.54	5.85
Average	29.58	32.82	35.63	35.85	35.68	35.38	35.10	34.12	59.01	59.56	60.30	61.33	63.73	65.94	68.61	71.16	74.22	77.60	81.60	85.18	89.31	93.74	98.12	104.13	111.22	117.49	124.71
Exports 10/	55.75	67.10	67.01	67.20	67.10	65.82	65.62	64.86	63.87	62.95	63.32	64.23	65.76	67.19	67.69	69.09	69.53	70.24	70.96	71.19	71.45	71.47	71.74	71.98	72.40	72.70	73.21

1/ Includes anthracite, bituminous coal, subbituminous coal, and lignite.
2/ Includes waste coal consumed by the electric power and industrial sectors. Waste coal supplied is counted as a supply-side item to balance the same amount of waste coal included in the consumption data.
3/ Excludes imports to Puerto Rico and the U.S. Virgin Islands.
4/ Production plus waste coal supplied plus net imports.
5/ Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public. Excludes all coal in the coal-to-liquids process.
6/ Includes all electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
7/ Balancing item: the sum of production, net imports, and waste coal supplied minus total consumption.
8/ Includes reported prices for both open market and captive mines.
9/ Prices weighted by consumption; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
10/ F.a.s. price at U.S. port of exit.
N/A = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
Sources: 2004 and 2005 data based on: Energy Information Administration (EIA), Annual Coal Report 2005, DOE/EIA-0584(2005) (Washington, DC, October 2006); EIA, Quarterly Coal Report, October-December 2005, DOE/EIA-0121(2005/4Q) (Washington, DC, March 2006); and EIA, AEO2007 National Energy Modeling System run s280base.d060107a.
Projections: EIA, AEO2007 National Energy Modeling System run s280.d060107a.

DEADLINE EVIDENCE 2007

Table 15 Coal Supply, Disposition, and Prices
(million short tons, unless otherwise noted)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Production 1/																											
Appalachia	391	397	393	379	363	357	346	331	334	327	320	315	305	299	278	271	266	258	251	236	230	218	196	197	171	145	137
Interior	146	149	145	148	149	149	164	163	163	168	179	174	182	173	162	156	152	150	144	142	139	134	126	72	82	123	98
West	575	585	609	620	583	580	566	562	585	575	574	557	545	537	523	488	462	436	414	379	367	346	314	280	242	202	146
East of the Mississippi	485	494	490	478	461	456	457	442	447	441	419	428	425	419	389	385	337	368	359	342	333	314	284	241	231	237	209
West of the Mississippi	627	638	657	668	633	630	619	614	636	627	633	618	607	590	574	530	502	478	450	415	403	384	352	308	265	233	172
Total	1112	1131	1147	1146	1095	1086	1076	1057	1083	1070	1072	1046	1032	1009	963	915	840	846	809	757	737	698	636	549	496	470	381
Waste Coal Supplied 2/	11	13	14	14	16	16	8	14	14	11	11	13	13	12	10	9	10	7	7	4	4	4	5	6	6	7	5
Net Imports																											
Imports 3/	26	29	32	37	37	37	37	37	38	38	40	44	45	46	65	69	61	47	41	31	35	29	27	29	25	13	15
Exports	48	50	49	53	52	51	50	49	48	47	46	46	44	43	44	45	45	45	45	46	45	45	45	45	44	44	44
Total	22	21	16	16	-15	-14	13	-12	-10	-9	-6	-1	1	2	22	24	16	2	-4	-15	-10	-16	-18	-16	-19	-31	-29
Total Supply 4/	1101	1124	1144	1144	1095	1088	1071	1059	1086	1072	1077	1058	1046	1023	994	948	906	854	812	746	731	686	623	539	483	446	357
Consumption by Sector																											
Residential and Commercial	5	5	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Coke Plants	24	23	24	23	22	22	22	22	21	21	21	21	20	20	20	20	19	19	19	19	19	19	19	18	18	18	18
Other Industrial 5/	62	61	64	62	63	63	63	63	59	58	58	58	57	57	56	56	56	55	56	55	55	55	55	55	55	55	54
Coal-to-Liquids Heat and Power	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Coal to Liquids Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Electric Power 6/	1016	1039	1038	1055	1006	998	981	969	1000	987	992	973	963	941	912	867	822	771	730	664	651	607	542	459	403	367	279
Total	1107	1128	1130	1144	1096	1088	1071	1058	1085	1071	1076	1056	1045	1022	993	947	902	851	809	743	730	686	621	538	481	444	357
Discrepancy and Stock Change 7/	-6	-5	14	0	0	0	0	0	1	1	1	2	1	1	1	1	4	4	3	3	1	1	2	2	2	2	1
Average Minemouth Price 8/																											
(2005 dollars per short ton)	20.68	23.34	24.09	24.04	23.76	23.35	23.19	22.50	22.27	22.04	21.77	21.67	21.63	21.65	21.26	21.72	21.80	21.74	21.85	21.83	21.67	21.46	21.15	21.88	21.90	22.40	24.15
(2005 dollars per million Btu)	1.01	1.15	1.17	1.18	1.16	1.14	1.14	1.11	1.09	1.08	1.07	1.07	1.07	1.07	1.05	1.06	1.06	1.06	1.06	1.05	1.05	1.04	1.03	1.06	1.05	1.07	1.13
Delivered Prices																											
(2005 dollars per short ton) 9/																											
Coke Plants	83.36	83.79	89.39	91.16	90.56	87.69	84.93	82.20	134.43	130.29	134.39	144.41	147.91	154.56	159.91	165.43	171.70	178.27	185.38	192.92	187.24	194.93	203.38	212.54	222.36	232.53	243.79
Other Industrial 5/	40.49	47.63	47.15	48.27	47.93	47.53	47.48	46.76	83.41	82.74	85.36	88.14	91.45	94.81	98.20	102.20	106.44	111.04	115.08	121.42	116.52	122.08	127.69	135.23	142.00	148.93	156.81
Coal to Liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electric Power																											
(2005 dollars per short ton)	28.12	30.83	33.73	33.96	33.69	33.19	32.85	31.62	65.50	64.87	66.99	69.71	72.47	75.81	79.21	83.68	87.47	91.56	96.48	101.22	96.55	101.01	105.42	112.41	118.98	124.01	133.59
(2005 dollars per million Btu)	1.40	1.53	1.68	1.70	1.69	1.66	1.64	1.59	3.29	3.26	3.38	3.52	3.66	3.82	3.99	4.17	4.35	4.56	4.79	5.02	4.79	5.04	5.29	5.65	5.95	6.26	6.63
Average	29.58	32.82	35.68	35.88	35.68	35.14	34.79	33.56	67.84	67.14	69.29	72.18	74.99	78.42	81.91	86.48	90.47	94.81	99.88	105.08	100.44	105.31	110.37	118.24	125.61	131.59	142.81
Exports 10/	55.75	67.10	67.05	67.23	67.09	65.68	65.48	64.75	63.71	63.04	63.50	64.43	66.45	68.27	68.35	69.00	70.34	70.61	71.00	71.05	71.26	71.23	71.54	72.25	72.61	72.57	72.98

1/ Includes anthracite, bituminous coal, subbituminous coal, and lignite.
2/ Includes waste coal consumed by the electric power and industrial sectors. Waste coal supplied is counted as a supply-side item to balance the same amount of waste coal included in the consumption data.
3/ Excludes imports to Puerto Rico and the U.S. Virgin Islands.
4/ Production plus waste coal supplied plus net imports.
5/ Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public. Excludes all coal in the coal-to-liquids process.
6/ Includes all electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
7/ Balancing item: the sum of production, net imports, and waste coal supplied minus total consumption.
8/ Includes reported prices for both open market and captive mines.
9/ Prices weighted by consumption; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
10/ F.a.s. price at U.S. port of exit.
N/A = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
Sources: 2004 and 2005 data based on: Energy Information Administration (EIA), Annual Coal Report 2005, DOE/EIA-0584(2005) (Washington, DC, October 2006); EIA, Quarterly Coal Report, October-December 2005, DOE/EIA-0121(2005/4Q) (Washington, DC, March 2006); and EIA, AEO2007 National Energy Modeling System run s280base.d060107a.
Projections: EIA, AEO2007 National Energy Modeling System run s280nointl.d061507a.

HEARING EXHIBIT - 00000190

Table 15 Coal Supply, Disposition, and Prices
(million short tons, unless otherwise noted)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Production 1/																											
Appalachia	391	397	394	381	371	372	368	361	365	353	348	341	337	327	313	310	301	298	292	293	291	290	288	287	282	280	279
Interior	146	149	148	150	151	153	169	171	175	180	186	184	181	181	178	169	162	155	152	152	151	152	155	159	166	166	168
West	575	585	607	616	611	612	610	612	619	623	625	617	619	620	616	616	609	601	603	604	602	599	593	580	569	558	549
East of the Mississippi	485	494	493	481	473	475	483	481	488	479	476	466	462	449	435	428	416	406	398	399	397	397	397	401	403	402	400
West of the Mississippi	627	638	655	666	663	662	663	665	671	677	683	676	676	679	671	666	657	648	649	650	648	644	638	625	614	602	597
Total	1112	1131	1148	1147	1136	1136	1146	1146	1159	1156	1159	1142	1138	1128	1108	1094	1073	1054	1047	1049	1045	1041	1035	1026	1017	1004	997
Waste Coal Supplied 2/	11	13	14	16	16	17	13	15	14	13	11	12	12	12	12	12	12	12	12	11	11	11	11	11	11	10	10
Net Imports																											
Imports 3/	26	29	32	37	37	37	37	37	37	38	40	42	40	50	63	69	76	74	73	74	73	72	74	76	77	76	70
Exports	48	50	49	53	52	51	50	49	48	47	46	44	42	39	39	41	42	42	42	46	45	45	45	45	45	45	44
Total	-22	-21	-16	-16	-15	-14	-13	-12	-11	-9	-6	-2	-2	11	24	28	34	32	31	28	27	28	29	31	32	31	26
Total Supply 4/	1101	1124	1146	1147	1136	1139	1146	1149	1162	1160	1166	1152	1147	1151	1143	1133	1119	1097	1090	1089	1084	1080	1075	1069	1061	1046	1033
Consumption by Sector																											
Residential and Commercial	5	5	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Coke Plants	24	23	24	23	22	22	22	22	22	21	21	21	21	20	20	20	20	20	20	20	20	20	20	19	19	19	19
Other Industrial 5/	62	61	64	62	63	63	63	63	62	61	60	60	60	59	59	59	59	59	58	58	58	58	58	58	58	59	58
Coal-to-Liquids Heat and Power	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Coal to Liquids Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Electric Power 6/	1016	1039	1040	1058	1046	1049	1056	1059	1074	1073	1079	1066	1062	1066	1058	1049	1034	1013	1007	1005	1000	996	992	985	977	962	950
Total	1107	1128	1132	1146	1136	1139	1146	1149	1162	1160	1166	1152	1147	1150	1143	1132	1118	1096	1090	1088	1082	1078	1074	1067	1060	1044	1032
Discrepancy and Stock Change 7/	-6	-5	14	0	0	0	0	0	0	0	1	1	1	0	1	1	1	1	1	1	1	1	1	1	1	1	1
Average Minemouth Price 8/																											
(2005 dollars per short ton)	20.68	23.34	24.04	24.09	23.71	23.50	23.83	23.19	23.04	22.56	22.25	22.03	21.97	21.74	21.44	21.36	21.27	21.26	21.15	21.13	21.18	21.29	21.34	21.58	21.77	21.83	21.98
(2005 dollars per million Btu)	1.01	1.15	1.17	1.18	1.16	1.15	1.17	1.14	1.13	1.11	1.10	1.09	1.08	1.08	1.06	1.06	1.05	1.05	1.05	1.05	1.05	1.05	1.06	1.06	1.07	1.07	1.08
Delivered Prices																											
(2005 dollars per short ton) 9/																											
Coke Plants	83.36	83.79	89.34	91.08	90.54	87.68	84.86	82.02	99.11	98.19	102.74	104.13	106.44	108.65	111.29	115.53	119.52	122.85	126.26	138.20	142.30	146.68	152.87	157.87	163.29	169.09	175.34
Other Industrial 5/	40.49	47.63	47.22	48.33	48.28	48.08	48.37	47.22	62.63	63.64	64.89	66.30	67.88	69.34	70.81	72.72	74.77	77.19	79.74	82.37	85.31	88.65	92.03	95.76	99.28	102.79	107.44
Coal to Liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electric Power																											
(2005 dollars per short ton)	28.12	30.83	33.64	33.91	33.88	33.64	33.74	32.74	47.07	47.57	48.48	49.54	50.85	52.25	53.62	55.41	57.37	59.50	61.88	64.27	66.95	70.08	73.18	76.90	80.74	84.62	88.82
(2005 dollars per million Btu)	1.40	1.53	1.67	1.70	1.70	1.69	1.69	1.64	2.36	2.39	2.44	2.49	2.56	2.63	2.70	2.79	2.88	2.99	3.11	3.23	3.37	3.53	3.68	3.85	4.04	4.23	4.45
Average	29.58	32.82	35.60	35.82	35.81	35.50	35.54	34.49	48.87	49.35	50.32	51.42	52.75	54.14	55.54	57.39	59.41	61.61	64.02	66.59	69.31	72.48	75.66	79.41	83.28	87.20	91.48
Exports 10/	55.75	67.10	66.94	67.21	67.21	66.01	65.73	64.97	64.63	63.54	63.20	63.91	66.02	66.51	66.97	67.84	68.59	69.15	69.58	70.21	71.15	71.30	71.79	72.15	72.53	72.94	73.43

1/ Includes anthracite, bituminous coal, subbituminous coal, and lignite.
2/ Includes waste coal consumed by the electric power and industrial sectors. Waste coal supplied is counted as a supply-side item to balance the same amount of waste coal included in the consumption data.
3/ Excludes imports to Puerto Rico and the U.S. Virgin Islands.
4/ Production plus waste coal supplied plus net imports.
5/ Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public. Excludes all coal in the coal-to-liquids process.
6/ Includes all electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
7/ Balancing item: the sum of production, net imports, and waste coal supplied minus total consumption.
8/ Includes reported prices for both open market and captive mines.
9/ Prices weighted by consumption; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
10/ F.a.s. price at U.S. port of exit.
N/A = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
Sources: 2004 and 2005 data based on: Energy Information Administration (EIA), Annual Coal Report 2005, DOE/EIA-0584(2005) (Washington, DC, October 2006); EIA, Quarterly Coal Report, October-December 2005, DOE/EIA-0121(2005/4Q) (Washington, DC, March 2006); and EIA, AEO2007 National Energy Modeling System run s280base.d060107a.
Projections: EIA, AEO2007 National Energy Modeling System run s280straw.d060207a.

HEARING EXHIBIT 00000104

Table 15. Coal Supply, Disposition, and Prices
(million short tons, unless otherwise noted)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Production 1/																											
Appalachia	391	397	393	379	367	365	354	341	344	340	323	320	320	301	286	276	273	267	266	265	259	253	249	247	248	244	245
Interior	146	149	145	148	149	151	166	166	171	173	159	172	167	162	155	151	145	141	142	141	139	135	135	143	155	152	136
West	575	585	609	620	597	599	587	587	597	585	590	570	568	562	545	535	527	519	505	488	467	431	416	392	362	345	318
East of the Mississippi	485	494	490	479	466	466	467	454	460	457	436	434	431	409	391	377	372	364	364	365	359	349	345	348	362	359	358
West of the Mississippi	627	638	657	668	647	649	640	639	651	641	636	628	624	616	595	584	572	563	548	528	505	471	455	435	403	382	341
Total	1112	1131	1147	1147	1113	1115	1107	1093	1112	1098	1072	1062	1055	1025	987	962	944	928	912	894	864	819	800	783	765	741	699
Waste Coal Supplied 2/	11	13	14	14	16	17	8	15	13	12	14	14	14	14	14	14	13	12	10	7	5	7	9	8	6	6	11
Net Imports																											
Imports 3/	26	29	32	37	37	37	37	37	37	38	40	42	43	60	73	74	78	74	70	65	65	65	62	65	65	55	56
Exports	48	50	49	53	52	51	50	49	48	47	46	44	43	42	43	45	46	46	46	46	45	45	45	45	45	44	44
Total	-22	-21	-16	-16	-15	-14	-13	-12	-11	9	-6	2	0	17	29	29	31	29	25	19	19	20	18	20	20	11	12
Total Supply 4/	1101	1124	1145	1145	1114	1117	1102	1096	1113	1101	1079	1073	1069	1056	1030	1005	987	969	947	920	888	847	826	810	791	758	722
Consumption by Sector																											
Residential and Commercial	5	5	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Coke Plants	24	23	24	23	22	22	22	22	21	21	21	21	20	20	20	20	20	20	19	19	19	19	19	19	19	18	18
Other Industrial 5/	62	61	64	62	63	63	63	64	60	59	59	58	58	58	57	57	57	57	56	56	56	56	56	56	56	55	55
Coal-to-Liquids Heat and Power	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Coal to Liquids Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Electric Power 6/	1016	1039	1039	1056	1024	1027	1012	1006	1026	1015	994	988	984	972	946	921	904	886	865	838	807	765	746	730	711	678	644
Total	1107	1128	1131	1145	1114	1117	1102	1096	1113	1100	1079	1072	1068	1055	1029	1003	986	967	946	919	887	845	825	809	790	757	722
Discrepancy and Stock Change 7/	-6	-5	14	0	0	0	0	0	1	1	1	1	1	1	1	2	2	2	1	2	1	1	1	1	1	1	0
Average Minemouth Price 8/																											
(2005 dollars per short ton)	20.68	23.34	24.09	24.06	23.73	23.45	23.42	22.84	22.60	22.38	22.00	22.02	22.03	21.67	21.42	21.22	21.21	21.20	21.42	21.60	21.69	21.91	21.86	22.05	23.28	23.65	24.23
(2005 dollars per million Btu)	1.01	1.15	1.17	1.18	1.16	1.15	1.15	1.12	1.11	1.10	1.08	1.08	1.08	1.07	1.06	1.05	1.04	1.04	1.05	1.06	1.06	1.06	1.06	1.07	1.12	1.13	1.14
Delivered Prices																											
(2005 dollars per short ton) 9/																											
Coke Plants	63.36	83.79	89.49	91.12	90.52	87.69	84.89	82.12	118.98	117.33	119.91	122.38	125.58	134.45	142.11	146.46	152.86	157.90	163.57	169.46	175.86	182.78	190.08	198.11	206.98	216.39	226.55
Other Industrial 5/	40.49	47.63	47.16	48.32	48.07	47.92	47.88	46.83	73.16	74.66	76.45	78.56	81.02	83.41	86.13	89.09	92.39	96.08	100.25	104.62	109.31	114.32	119.57	125.15	132.12	139.10	146.53
Coal to Liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electric Power																											
(2005 dollars per short ton)	28.12	30.83	33.73	33.97	33.76	33.47	33.22	32.25	56.75	57.43	59.10	60.91	63.32	65.66	68.06	70.78	74.16	77.44	81.43	85.61	90.21	95.19	100.10	105.90	113.42	120.85	129.51
(2005 dollars per million Btu)	1.40	1.53	1.68	1.70	1.69	1.68	1.66	1.62	2.85	2.88	2.97	3.06	3.18	3.30	3.42	3.56	3.72	3.88	4.07	4.27	4.48	4.71	4.96	5.23	5.55	5.88	6.25
Average	29.58	32.82	35.68	35.88	35.72	35.37	35.10	34.09	58.85	59.51	61.24	63.07	65.49	67.96	70.51	73.33	76.80	80.17	84.25	88.54	93.28	98.45	103.50	109.40	116.98	124.54	133.28
Exports 10/	55.75	67.10	67.11	67.20	67.13	65.87	65.60	64.85	63.86	63.04	63.37	64.28	65.90	67.43	68.22	69.10	69.63	70.23	71.04	71.26	71.52	71.69	71.93	72.19	72.96	73.41	74.06

1/ Includes anthracite, bituminous coal, subbituminous coal, and lignite.
2/ Includes waste coal consumed by the electric power and industrial sectors. Waste coal supplied is counted as a supply-side item to balance the same amount of waste coal included in the consumption data.
3/ Excludes imports to Puerto Rico and the U.S. Virgin Islands.
4/ Production plus waste coal supplied plus net imports.
5/ Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public. Excludes all coal in the coal-to-liquids process.
6/ Includes all electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
7/ Balancing item: the sum of production, net imports, and waste coal supplied minus total consumption.
8/ Includes reported prices for both open market and captive mines.
9/ Prices weighted by consumption; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
10/ F.a.s. price at U.S. port of exit.
N/A = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
Sources: 2004 and 2005 data based on: Energy Information Administration (EIA), Annual Coal Report 2005, DOE/EIA-0584(2005) (Washington, DC, October 2006); EIA, Quarterly Coal Report, October-December 2005, DOE/EIA-0121(2005/4Q) (Washington, DC, March 2006); and EIA, AEO2007 National Energy Modeling System run s280base.d060107a.
Projections: EIA, AEO2007 National Energy Modeling System run s280nuc.d060207a.

EFADOCID: 2222222

Table 15. Coal Supply, Disposition, and Prices
(million short tons, unless otherwise noted)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Production 1/																											
Appalachia	391	397	394	380	363	362	349	335	343	330	330	321	317	316	299	291	293	286	282	278	277	276	274	271	266	260	256
Interior	146	149	146	148	158	153	170	166	168	176	181	177	177	165	164	166	165	161	161	161	157	162	162	161	157	161	158
West	575	585	608	618	578	584	572	574	591	580	570	560	558	567	567	566	555	555	539	531	525	517	514	509	496	472	455
East of the Mississippi	485	494	491	480	464	463	463	450	461	453	452	443	438	436	418	413	414	403	399	395	391	395	394	390	381	377	370
West of the Mississippi	627	638	657	667	634	636	628	626	641	634	629	615	614	612	613	611	600	599	583	575	568	560	556	551	537	517	497
Total	1112	1131	1148	1147	1098	1099	1091	1075	1102	1086	1082	1059	1052	1048	1030	1023	1014	1002	982	970	959	955	949	941	918	894	868
Waste Coal Supplied 2/	11	13	14	15	16	17	8	13	12	11	11	11	11	11	11	11	10	10	10	10	10	9	10	10	10	10	9
Net Imports																											
Imports 3/	26	29	32	37	37	37	37	37	37	38	40	42	45	48	67	71	73	76	74	71	68	64	57	59	57	53	49
Exports	48	50	49	53	52	51	50	49	48	47	46	45	44	43	44	45	46	46	46	46	46	45	45	45	45	44	44
Total	-22	-21	-16	-16	-15	-14	-13	-12	-11	-9	-6	-3	1	5	23	26	27	30	27	25	22	19	12	14	12	9	5
Total Supply 4/	1101	1124	1146	1146	1099	1102	1085	1076	1103	1088	1086	1067	1063	1064	1064	1060	1051	1042	1020	1004	991	984	971	965	940	912	882
Consumption by Sector																											
Residential and Commercial	5	5	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Coke Plants	24	23	24	23	22	22	22	22	21	21	21	21	20	20	20	20	20	20	20	19	19	19	19	19	19	19	19
Other Industrial 5/	62	61	64	62	63	63	63	64	60	59	58	58	58	58	57	57	57	57	57	57	57	57	57	57	57	57	57
Coal-to-Liquids Heat and Power	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Coal to Liquids Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Electric Power 6/	1016	1039	1040	1057	1009	1012	995	986	1016	1002	1001	982	979	980	980	977	967	959	938	922	909	901	888	882	858	830	799
Total	1107	1128	1132	1146	1099	1102	1085	1076	1102	1087	1085	1066	1062	1063	1062	1059	1049	1040	1019	1003	990	982	969	963	939	911	880
Discrepancy and Stock Change 7/	-6	-5	14	0	0	0	0	0	1	1	1	1	2	1	1	1	2	2	0	2	1	2	2	2	1	1	1
Average Minemouth Price 8/																											
(2005 dollars per short ton)	20.68	23.34	24.03	24.09	23.84	23.52	23.47	22.75	22.56	22.27	22.13	22.13	22.03	21.94	21.50	21.45	21.53	21.40	21.64	21.65	21.52	21.68	21.74	21.81	21.84	21.99	22.05
(2005 dollars per million Btu)	1.01	1.15	1.17	1.18	1.17	1.15	1.15	1.12	1.11	1.10	1.09	1.09	1.08	1.08	1.08	1.06	1.06	1.05	1.06	1.06	1.06	1.06	1.07	1.07	1.07	1.07	1.07
Delivered Prices																											
(2005 dollars per short ton) 9/																											
Coke Plants	83.36	83.79	89.47	91.16	90.55	87.67	84.88	82.25	128.42	127.22	126.45	129.70	136.75	140.38	142.71	144.80	147.20	151.45	154.31	157.05	159.71	162.60	165.57	168.75	172.09	175.44	178.96
Other Industrial 5/	40.49	47.63	47.19	48.29	48.05	47.89	47.94	46.57	78.86	80.66	81.50	82.70	84.12	85.52	86.57	87.98	89.45	90.79	93.17	94.99	96.90	98.94	100.77	102.94	105.35	107.27	108.93
Coal to Liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electric Power																											
(2005 dollars per short ton)	28.12	30.83	33.66	33.95	33.65	33.35	33.14	32.03	62.31	62.76	63.68	65.00	66.21	67.68	68.68	69.99	71.54	73.01	74.94	76.57	78.33	80.41	82.18	84.27	86.37	88.51	90.92
(2005 dollars per million Btu)	1.40	1.53	1.68	1.70	1.69	1.67	1.66	1.61	3.12	3.15	3.20	3.26	3.32	3.38	3.44	3.51	3.58	3.66	3.74	3.83	3.91	4.01	4.11	4.21	4.31	4.42	4.52
Average	29.58	32.82	35.62	35.86	35.64	35.28	35.06	33.91	64.50	64.98	65.85	67.23	68.56	70.04	71.05	72.38	73.95	75.48	77.49	79.19	81.00	83.12	84.96	87.08	89.29	91.53	94.01
Exports 10/	55.75	67.10	67.03	67.25	67.03	65.78	65.58	64.82	63.79	62.94	63.23	64.17	66.65	68.07	67.99	68.99	69.37	70.02	70.37	71.19	71.30	71.38	71.54	71.99	72.33	72.70	73.07

1/ Includes anthracite, bituminous coal, subbituminous coal, and lignite.
2/ Includes waste coal consumed by the electric power and industrial sectors. Waste coal supplied is counted as a supply-side item to balance the same amount of waste coal included in the consumption data.
3/ Excludes imports to Puerto Rico and the U.S. Virgin Islands.
4/ Production plus waste coal supplied plus net imports.
5/ Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public. Excludes all coal in the coal-to-liquids process.
6/ Includes all electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
7/ Balancing item: the sum of production, net imports, and waste coal supplied minus total consumption.
8/ Includes reported prices for both open market and captive mines.
9/ Prices weighted by consumption; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
10/ F.a.s. price at U.S. port of exit.
N/A = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
Sources: 2004 and 2005 data based on: Energy Information Administration (EIA), Annual Coal Report 2005, DOE/EIA-0584(2005) (Washington, DC, October 2006); EIA, Quarterly Coal Report, October-December 2005, DOE/EIA-0121(2005/4Q) (Washington, DC, March 2006); and EIA, AEO2007 National Energy Modeling System run s280base.d060107a.
Projections: EIA, AEO2007 National Energy Modeling System run s280r4.d061507a.

HEARING EXHIBIT

Table 15. Coal Supply, Disposition, and Prices
(million short tons, unless otherwise noted)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Production 1/																											
Appalachia	391	397	394	381	368	367	354	344	346	337	333	325	325	318	306	297	291	292	294	295	297	293	285	285	282	280	279
Interior	146	149	147	148	156	152	170	167	171	171	178	182	184	180	166	163	158	156	160	164	165	156	153	154	162	161	169
West	575	585	608	617	597	598	589	588	600	599	596	577	568	579	586	578	572	581	581	591	597	606	611	597	574	561	549
East of the Mississippi	485	494	492	481	470	470	469	458	466	458	454	446	445	436	424	412	401	401	407	411	412	402	391	391	398	395	396
West of the Mississippi	627	638	657	666	652	648	644	641	651	650	651	619	612	641	634	626	619	628	629	640	647	653	658	643	621	608	601
Total	1112	1131	1149	1147	1121	1118	1113	1099	1117	1108	1107	1065	1057	1077	1058	1038	1020	1030	1035	1051	1059	1055	1048	1035	1018	1002	997
Waste Coal Supplied 2/	11	13	14	15	16	17	10	13	14	12	12	12	11	12	11	11	11	11	11	11	11	11	11	11	10	11	11
Net Imports																											
Imports 3/	26	29	32	37	37	37	37	37	37	38	40	42	43	52	65	72	80	76	76	70	70	68	73	75	71	76	64
Exports	48	50	49	53	52	51	50	49	48	47	46	44	43	39	41	41	45	46	46	43	42	41	45	44	45	45	44
Total	-22	-21	-16	-16	-15	-14	-13	-12	-11	-9	-6	-2	0	13	23	31	34	30	30	27	29	27	29	31	26	31	20
Total Supply 4/	1101	1124	1146	1146	1122	1121	1110	1100	1119	1110	1113	1094	1089	1101	1093	1080	1066	1071	1077	1089	1099	1093	1088	1076	1055	1045	1027
Consumption by Sector																											
Residential and Commercial	5	5	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Coke Plants	24	23	24	23	22	22	22	22	21	21	21	21	21	20	20	20	20	20	20	20	20	20	20	19	19	19	19
Other Industrial 5/	62	61	64	62	63	63	63	64	60	59	59	59	59	58	58	56	58	58	58	58	58	58	58	58	58	58	58
Coal-to-Liquids Heat and Power	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Coal to Liquids Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Electric Power 6/	1016	1039	1040	1057	1032	1031	1020	1010	1032	1024	1027	1008	1004	1016	1009	995	981	987	993	1006	1015	1010	1005	993	971	961	944
Total	1107	1128	1132	1146	1122	1121	1110	1100	1119	1110	1112	1093	1088	1099	1092	1078	1063	1069	1075	1088	1097	1092	1087	1075	1053	1044	1026
Discrepancy and Stock Change 7/	-6	-5	14	0	0	0	0	0	1	1	0	1	1	2	1	2	2	2	2	1	1	1	1	1	1	1	2
Average Minemouth Price 8/																											
(2005 dollars per short ton)	20.68	23.34	24.01	24.10	23.75	23.53	23.44	22.86	22.73	22.22	21.94	21.98	22.13	21.80	21.55	21.49	21.35	21.28	21.27	21.14	21.17	21.10	20.89	21.12	21.35	21.40	21.56
(2005 dollars per million Btu)	1.01	1.15	1.17	1.18	1.16	1.15	1.15	1.12	1.12	1.09	1.08	1.08	1.09	1.08	1.06	1.06	1.05	1.05	1.05	1.05	1.05	1.05	1.04	1.05	1.06	1.06	1.07
Delivered Prices																											
(2005 dollars per short ton) 9/																											
Coke Plants	63.36	83.79	89.35	91.09	90.54	87.65	84.96	82.14	119.31	117.74	119.57	120.11	120.81	121.65	123.68	127.57	139.93	140.56	137.31	126.55	124.55	127.80	140.19	144.38	149.46	155.05	160.22
Other Industrial 5/	40.49	47.63	47.21	48.29	48.16	47.97	48.02	46.79	73.48	75.06	76.06	76.82	77.40	77.79	79.03	81.59	84.26	84.37	81.50	79.21	77.62	80.50	83.32	86.42	89.51	92.07	95.92
Coal to Liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electric Power																											
(2005 dollars per short ton)	28.12	30.83	33.65	33.95	33.72	33.50	33.20	32.32	57.17	57.64	58.43	59.15	59.69	60.12	61.35	63.74	66.19	66.29	63.59	61.40	59.95	62.47	64.89	67.85	70.91	74.10	77.38
(2005 dollars per million Btu)	1.40	1.53	1.67	1.70	1.69	1.68	1.66	1.62	2.86	2.89	2.94	2.98	3.00	3.02	3.08	3.19	3.32	3.33	3.19	3.09	3.01	3.15	3.28	3.42	3.56	3.72	3.90
Average	29.58	32.82	35.60	35.86	35.68	35.39	35.08	34.15	59.25	59.73	60.52	61.27	61.81	62.20	63.45	65.89	68.55	68.64	65.91	63.53	62.05	64.61	67.23	70.25	73.39	76.62	80.00
Exports 10/	55.75	67.10	66.95	67.23	67.14	65.89	65.65	64.85	63.92	63.07	63.43	64.29	65.92	67.50	67.02	68.12	69.48	69.97	70.00	69.41	70.07	70.07	71.24	71.65	72.07	72.51	73.01

1/ Includes anthracite, bituminous coal, subbituminous coal, and lignite.
2/ Includes waste coal consumed by the electric power and industrial sectors. Waste coal supplied is counted as a supply-side item to balance the same amount of waste coal included in the consumption data.
3/ Excludes imports to Puerto Rico and the U.S. Virgin Islands.
4/ Production plus waste coal supplied plus net imports.
5/ Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public. Excludes all coal in the coal-to-liquids process.
6/ Includes all electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
7/ Balancing item: the sum of production, net imports, and waste coal supplied minus total consumption.
8/ Includes reported prices for both open market and captive mines.
9/ Prices weighted by consumption; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
10/ F.a.s. price at U.S. port of exit.
N/A = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
Sources: 2004 and 2005 data based on: Energy Information Administration (EIA), Annual Coal Report 2005, DOE/EIA-0584(2005) (Washington, DC, October 2006); EIA, Quarterly Coal Report, October-December 2005, DOE/EIA-0121(2005/4Q) (Washington, DC, March 2006); and EIA, AEO2007 National Energy Modeling System run s280base.d060107a.
Projections: EIA, AEO2007 National Energy Modeling System run s280vhioff25.d061607a.

HEARING EXHIBIT 20000000

Table 15. Coal Supply, Disposition, and Prices
(million short tons, unless otherwise noted)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Production 1/																											
Appalachia	391	397	393	379	365	365	355	341	343	337	333	326	320	315	296	293	283	272	272	269	265	259	255	237	226	204	174
Interior	146	149	145	148	149	152	165	166	168	170	173	174	174	171	166	151	148	151	155	147	146	154	151	153	147	133	123
West	575	585	609	619	600	593	585	584	600	593	591	578	575	577	569	558	543	523	513	507	502	470	442	401	347	310	241
East of the Mississippi	485	494	490	479	464	467	467	455	459	454	451	444	439	439	415	398	386	383	385	381	374	369	366	346	331	300	265
West of the Mississippi	627	638	657	668	650	643	638	637	652	647	646	633	630	624	616	605	588	563	555	543	539	515	483	445	389	347	273
Total	1112	1131	1147	1146	1113	1109	1105	1091	1111	1101	1097	1077	1069	1063	1031	1003	974	946	940	924	912	884	849	791	720	646	538
Waste Coal Supplied 2/	11	13	14	14	16	17	9	14	13	13	13	13	13	13	13	12	12	10	8	5	7	10	8	7	7	5	7
Net Imports																											
Imports 3/	26	29	32	37	37	37	37	37	37	38	40	46	46	46	65	73	76	72	67	62	58	54	41	40	38	33	28
Exports	48	50	49	53	52	51	50	49	48	47	46	44	42	40	43	45	46	46	46	46	46	45	45	45	45	44	44
Total	-22	-21	-16	-16	-15	-14	-13	-12	-11	-9	-6	1	4	7	21	28	30	26	21	16	12	9	-3	-5	-7	-11	-16
Total Supply 4/	1101	1124	1145	1145	1114	1112	1101	1094	1113	1105	1104	1092	1086	1083	1065	1043	1016	982	970	944	931	903	853	794	720	640	529
Consumption by Sector																											
Residential and Commercial	5	5	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Coke Plants	24	23	24	23	22	22	22	22	21	21	21	21	20	20	20	20	20	20	19	19	19	19	19	19	19	19	18
Other Industrial 5/	62	61	64	62	63	63	63	64	60	59	59	59	58	58	57	57	57	57	57	57	57	57	57	57	56	56	55
Coal-to-Liquids Heat and Power	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Coal to Liquids Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Electric Power 6/	1016	1039	1039	1056	1024	1022	1011	1004	1026	1019	1018	1007	1001	1000	982	960	934	900	888	862	849	820	771	713	639	559	448
Total	1107	1128	1131	1144	1114	1112	1101	1094	1113	1104	1103	1091	1085	1082	1064	1042	1015	981	968	943	930	901	852	793	719	638	527
Discrepancy and Stock Change 7/	-6	-5	14	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	2	2	1	1	2	2
Average Minemouth Price 8/																											
(2005 dollars per short ton)	20.68	23.34	24.02	24.06	23.64	23.50	23.38	22.80	22.56	22.31	21.96	21.88	21.87	21.83	21.47	21.38	21.30	21.49	21.60	21.59	21.43	21.65	21.95	21.98	22.60	22.44	23.22
(2005 dollars per million Btu)	1.01	1.15	1.17	1.18	1.16	1.15	1.14	1.12	1.11	1.10	1.08	1.08	1.08	1.07	1.06	1.05	1.05	1.05	1.06	1.05	1.05	1.06	1.07	1.07	1.09	1.08	1.10
Delivered Prices																											
(2005 dollars per short ton) 9/																											
Coke Plants	63.36	83.79	89.47	91.17	90.57	87.70	84.89	82.15	119.08	117.21	119.16	120.62	123.71	127.51	139.74	143.97	148.50	154.99	160.44	166.09	172.15	178.60	185.57	193.16	201.40	210.20	219.79
Other Industrial 5/	40.49	47.63	47.16	48.30	48.06	47.90	47.85	46.83	73.20	74.83	75.67	77.07	79.43	82.08	84.30	87.29	90.41	93.87	97.76	100.36	104.75	109.60	114.69	120.05	125.82	133.17	139.64
Coal to Liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electric Power																											
(2005 dollars per short ton)	28.12	30.83	33.67	33.94	33.72	33.47	33.19	32.21	56.80	57.46	58.18	59.47	61.74	64.13	66.36	69.21	72.06	75.64	79.24	83.26	86.93	91.02	95.84	100.72	106.85	112.10	118.36
(2005 dollars per million Btu)	1.40	1.53	1.68	1.70	1.69	1.68	1.66	1.62	2.85	2.89	2.93	2.99	3.10	3.22	3.33	3.47	3.61	3.77	3.95	4.13	4.33	4.55	4.78	5.02	5.30	5.56	5.84
Average	29.58	32.82	35.62	35.86	35.68	35.37	35.07	34.06	58.90	59.55	60.28	61.59	63.87	66.28	68.72	71.63	74.59	78.29	81.96	86.01	89.79	94.06	99.12	104.33	110.84	116.84	124.20
Exports 10/	55.75	67.10	67.06	67.23	67.20	65.85	65.59	64.84	63.94	63.18	63.45	64.37	66.50	67.35	68.24	69.09	69.32	70.04	70.79	71.30	71.36	71.51	71.67	71.97	72.33	72.63	73.05

1/ Includes anthracite, bituminous coal, subbituminous coal, and lignite.
2/ Includes waste coal consumed by the electric power and industrial sectors. Waste coal supplied is counted as a supply-side item to balance the same amount of waste coal included in the consumption data.
3/ Excludes imports to Puerto Rico and the U.S. Virgin Islands.
4/ Production plus waste coal supplied plus net imports.
5/ Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public. Excludes all coal in the coal-to-liquids process.
6/ Includes all electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
7/ Balancing item: the sum of production, net imports, and waste coal supplied minus total consumption.
8/ Includes reported prices for both open market and captive mines.
9/ Prices weighted by consumption; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
10/ F.a.s. price at U.S. port of exit.
N/A = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
Sources: 2004 and 2005 data based on: Energy Information Administration (EIA), Annual Coal Report 2005, DOE/EIA-0584(2005) (Washington, DC, October 2006); EIA, Quarterly Coal Report, October-December 2005, DOE/EIA-0121(2005/4Q) (Washington, DC, March 2006); and EIA, AEO2007 National Energy Modeling System run s280base.d060107a.
Projections: EIA, AEO2007 National Energy Modeling System run s280cc70.d060207a.

HEARING EXHIBIT

Table 15. Coal Supply, Disposition, and Prices
(million short tons, unless otherwise noted)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Production 1/																											
Appalachia	391	397	393	379	367	363	356	342	345	340	336	327	321	315	300	290	282	271	267	263	257	254	249	246	235	217	196
Interior	146	149	145	148	149	151	166	168	169	173	171	178	176	164	163	155	152	146	150	141	138	144	141	144	153	140	132
West	575	585	609	619	596	595	585	587	597	584	587	578	576	571	562	549	536	519	502	500	488	468	456	422	370	323	298
East of the Mississippi	485	494	490	479	466	464	468	457	461	458	452	446	439	426	410	394	384	373	375	363	355	357	350	353	343	318	290
West of the Mississippi	627	638	657	668	646	645	638	640	650	639	641	637	633	624	614	600	586	563	544	541	527	508	497	459	416	362	336
Total	1112	1131	1147	1146	1112	1109	1106	1097	1111	1097	1093	1083	1072	1050	1024	994	970	936	919	904	882	865	847	812	759	680	626
Waste Coal Supplied 2/	11	13	14	14	16	17	11	13	13	11	11	11	11	11	10	10	10	10	7	7	8	8	8	7	5	6	7
Net Imports																											
Imports 3/	26	29	32	37	37	37	37	37	37	38	40	42	43	50	65	76	79	79	72	68	70	59	48	39	39	40	32
Exports	48	50	49	53	52	51	50	49	48	47	46	44	42	40	43	45	46	46	46	45	45	45	45	45	45	44	44
Total	-22	-21	-16	-16	-15	-14	-13	-12	-11	-9	-6	2	1	9	22	31	33	33	26	22	25	14	3	-6	-6	-5	-12
Total Supply 4/	1101	1124	1145	1145	1113	1112	1104	1098	1113	1099	1097	1092	1084	1070	1057	1035	1013	979	952	934	915	887	858	812	758	682	621
Consumption by Sector																											
Residential and Commercial	5	5	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Coke Plants	24	23	24	23	22	22	22	22	21	21	21	21	21	20	20	20	20	20	19	19	19	19	19	19	19	19	19
Other Industrial 5/	62	61	64	62	63	63	63	63	60	59	59	59	59	58	58	57	57	57	57	57	57	57	57	57	57	56	56
Coal-to-Liquids Heat and Power	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Coal to Liquids Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Electric Power 6/	1016	1039	1039	1056	1023	1021	1014	1008	1026	1013	1012	1006	1000	986	973	952	930	895	870	851	833	805	776	730	677	600	540
Total	1107	1128	1131	1144	1113	1111	1104	1098	1112	1098	1096	1091	1084	1069	1055	1034	1012	978	951	932	914	886	856	811	757	680	619
Discrepancy and Stock Change 7/	-6	-5	14	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	2	1	1	2	2	1	2	2
Average Minemouth Price 8/																											
(2005 dollars per short ton)	20.68	23.34	24.03	24.04	23.71	23.45	23.47	22.88	22.65	22.45	22.06	22.01	21.92	21.74	21.47	21.44	21.34	21.39	21.60	21.39	21.39	21.52	21.45	22.05	22.64	22.90	22.62
(2005 dollars per million Btu)	1.01	1.15	1.17	1.18	1.16	1.15	1.15	1.12	1.11	1.10	1.08	1.08	1.08	1.07	1.06	1.06	1.05	1.05	1.06	1.05	1.05	1.05	1.05	1.07	1.10	1.10	1.09
Delivered Prices																											
(2005 dollars per short ton) 9/																											
Coke Plants	83.36	83.79	89.37	91.13	90.54	87.69	84.90	82.12	118.84	117.13	118.98	119.95	122.03	125.17	136.19	142.03	146.26	152.58	157.82	163.29	169.14	175.45	182.25	189.46	197.40	205.99	215.28
Other Industrial 5/	40.49	47.63	47.16	48.31	48.07	47.89	47.97	47.02	73.09	74.68	75.60	76.64	78.14	80.40	82.88	85.79	88.77	92.15	95.84	99.77	104.06	108.69	112.13	117.43	123.04	128.78	136.66
Coal to Liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electric Power																											
(2005 dollars per short ton)	28.12	30.83	33.66	33.91	33.71	33.43	33.21	32.30	56.72	57.60	58.31	59.15	60.59	62.90	65.06	67.90	70.61	73.80	77.48	80.84	84.79	89.01	93.13	98.50	104.23	110.14	115.02
(2005 dollars per million Btu)	1.40	1.53	1.68	1.69	1.69	1.68	1.66	1.62	2.84	2.89	2.93	2.97	3.04	3.16	3.27	3.40	3.54	3.69	3.86	4.03	4.23	4.44	4.65	4.89	5.16	5.43	5.72
Average	29.58	32.82	35.61	35.83	35.67	35.34	35.09	34.14	58.81	59.68	60.41	61.26	62.71	65.04	67.39	70.33	73.12	76.47	80.23	83.71	87.77	92.15	96.40	101.98	107.99	114.35	120.01
Exports 10/	55.75	67.10	67.02	67.22	67.11	65.79	65.73	64.89	63.88	62.98	63.30	64.45	66.35	66.84	68.27	69.32	69.49	70.09	70.90	71.10	71.37	71.47	71.76	72.02	72.38	72.70	73.19

1/ Includes anthracite, bituminous coal, subbituminous coal, and lignite.
2/ Includes waste coal consumed by the electric power and industrial sectors. Waste coal supplied is counted as a supply-side item to balance the same amount of waste coal included in the consumption data.
3/ Excludes imports to Puerto Rico and the U.S. Virgin Islands.
4/ Production plus waste coal supplied plus net imports.
5/ Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public. Excludes all coal in the coal-to-liquids process.
6/ Includes all electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
7/ Balancing item: the sum of production, net imports, and waste coal supplied minus total consumption.
8/ Includes reported prices for both open market and captive mines.
9/ Prices weighted by consumption; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
10/ F.a.s. price at U.S. port of exit.
N/A = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
Sources: 2004 and 2005 data based on: Energy Information Administration (EIA), Annual Coal Report 2005, DOE/EIA-0584(2005) (Washington, DC, October 2006); EIA, Quarterly Coal Report, October-December 2005, DOE/EIA-0121(2005/4Q) (Washington, DC, March 2006); and EIA, AEO2007 National Energy Modeling System run s280base.d060107a.
Projections: EIA, AEO2007 National Energy Modeling System run s280comm.d061507a.

HEARING EXHIBIT 2010-00___

Table 15. Coal Supply, Disposition, and Prices
(million short tons, unless otherwise noted)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Production 1/																											
Appalachia	391	397	395	380	376	381	376	374	370	369	365	359	352	342	330	331	327	328	326	323	319	320	318	325	333	338	344
Interior	146	149	148	151	153	157	172	179	182	189	189	185	186	183	183	181	180	178	187	190	190	193	197	200	205	211	218
West	575	585	606	615	622	627	636	638	644	648	665	676	684	695	704	712	726	745	764	785	818	836	866	900	905	935	950
East of the Mississippi	485	494	494	480	479	487	494	498	499	500	497	489	483	469	457	456	452	450	450	446	445	449	450	461	472	482	493
West of the Mississippi	627	638	654	666	672	677	689	692	698	705	722	731	740	750	760	768	781	802	828	851	882	900	930	965	971	1002	1018
Total	1112	1131	1149	1146	1150	1165	1183	1190	1197	1205	1219	1221	1222	1219	1217	1224	1233	1251	1278	1297	1327	1349	1381	1425	1443	1484	1512
Waste Coal Supplied 2/	11	13	14	16	16	18	10	14	14	13	13	13	13	13	13	13	13	13	13	13	13	12	12	12	12	12	13
Net Imports																											
Imports 3/	26	29	32	37	37	37	37	37	37	38	40	42	45	54	63	65	69	71	70	70	70	72	73	74	76	77	75
Exports	48	50	49	53	52	51	50	49	48	47	46	41	39	36	35	36	37	38	38	38	37	37	36	36	36	36	36
Total	-22	-21	-16	-16	-15	-14	-13	-12	-11	-9	-6	1	6	17	28	29	32	33	33	33	33	35	37	38	40	41	39
Total Supply 4/	1101	1124	1147	1146	1151	1168	1180	1192	1199	1208	1226	1234	1241	1250	1257	1266	1278	1297	1323	1343	1373	1396	1430	1475	1495	1538	1564
Consumption by Sector																											
Residential and Commercial	5	5	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Coke Plants	24	23	24	22	22	21	21	21	20	20	20	20	19	19	19	18	18	18	18	18	18	18	18	18	17	17	17
Other Industrial 5/	62	61	64	62	62	63	63	63	62	61	61	61	61	61	60	60	60	60	60	60	61	61	61	61	61	61	61
Coal-to-Liquids Heat and Power	0	0	0	0	0	0	0	0	0	0	2	4	6	8	8	8	9	11	14	16	20	22	31	43	43	53	52
Coal to Liquids Production	0	0	0	0	0	0	0	0	0	0	2	4	5	8	8	8	9	11	14	15	19	22	30	41	42	52	50
Electric Power 6/	1016	1039	1041	1058	1062	1079	1092	1104	1112	1122	1136	1141	1144	1150	1158	1166	1177	1192	1212	1229	1250	1269	1286	1307	1327	1349	1378
Total	1107	1128	1133	1146	1151	1168	1180	1192	1199	1208	1226	1234	1240	1250	1257	1265	1278	1297	1323	1343	1372	1396	1429	1474	1495	1537	1563
Discrepancy and Stock Change 7/	-6	-5	14	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	1	0	1	0
Average Minemouth Price 8/																											
(2005 dollars per short ton)	20.68	23.34	24.06	24.07	23.73	23.64	23.93	23.42	22.94	22.59	22.21	21.84	21.65	21.30	20.96	20.93	20.74	20.65	20.67	20.50	20.44	20.61	20.54	20.78	21.07	21.18	21.39
(2005 dollars per million Btu)	1.01	1.15	1.17	1.18	1.16	1.16	1.17	1.15	1.13	1.11	1.10	1.08	1.07	1.06	1.04	1.04	1.04	1.03	1.04	1.03	1.03	1.04	1.04	1.06	1.07	1.08	1.09
Delivered Prices																											
(2005 dollars per short ton) 9/																											
Coke Plants	63.36	83.79	89.33	90.97	90.40	87.29	84.36	81.36	78.64	75.91	74.91	73.89	73.86	73.65	73.89	74.44	74.92	75.37	75.61	75.77	75.95	76.36	76.36	76.59	76.90	77.07	77.26
Other Industrial 5/	40.49	47.63	47.24	48.31	48.38	48.35	48.62	47.56	47.19	47.06	46.85	46.63	46.54	46.29	46.09	46.09	45.93	45.95	46.13	46.10	45.73	45.95	46.02	46.36	46.70	46.93	46.92
Coal to Liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.08	13.35	13.62	13.74	13.78	13.89	14.01	14.27	15.36	15.08	15.41	15.58	16.32	19.35	19.51	20.23	20.05
Electric Power																											
(2005 dollars per short ton)	28.12	30.83	33.65	33.87	34.02	33.90	34.11	33.17	32.51	31.90	31.59	31.39	31.27	31.06	30.64	30.56	30.31	30.22	30.22	30.02	30.16	30.43	30.56	30.91	31.25	31.52	31.77
(2005 dollars per million Btu)	1.40	1.53	1.67	1.69	1.70	1.70	1.70	1.66	1.63	1.60	1.59	1.58	1.57	1.56	1.55	1.54	1.53	1.53	1.53	1.53	1.54	1.55	1.55	1.57	1.59	1.60	1.61
Average	29.58	32.82	35.60	35.77	35.89	35.66	35.78	34.77	34.06	33.41	33.00	32.70	32.53	32.23	31.82	31.74	31.46	31.30	31.25	31.01	31.03	31.22	31.19	31.44	31.75	31.87	32.10
Exports 10/	55.75	67.10	66.95	67.15	67.27	65.93	65.59	64.87	64.15	63.26	63.31	62.72	63.88	64.37	64.86	65.56	66.01	66.57	66.50	67.06	67.23	67.73	67.56	67.88	68.31	68.64	69.03

1/ Includes anthracite, bituminous coal, subbituminous coal, and lignite.
2/ Includes waste coal consumed by the electric power and industrial sectors. Waste coal supplied is counted as a supply-side item to balance the same amount of waste coal included in the consumption data.
3/ Excludes imports to Puerto Rico and the U.S. Virgin Islands.
4/ Production plus waste coal supplied plus net imports.
5/ Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public. Excludes all coal in the coal-to-liquids process.
6/ Includes all electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
7/ Balancing item: the sum of production, net imports, and waste coal supplied minus total consumption.
8/ Includes reported prices for both open market and captive mines.
9/ Prices weighted by consumption; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
10/ F.a.s. price at U.S. port of exit.
N/A = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
Sources: 2004 and 2005 data based on: Energy Information Administration (EIA), Annual Coal Report 2005, DOE/EIA-0584(2005) (Washington, DC, October 2006); EIA, Quarterly Coal Report, October-December 2005, DOE/EIA-0121(2005/4Q) (Washington, DC, March 2006); and EIA, AEO2007 National Energy Modeling System run s280base.d060107a.
Projections: EIA, AEO2007 National Energy Modeling System run htrkiten d060107a.

HEARING EXHIBIT - 00000197

Table 15. Coal Supply, Disposition, and Prices
(million short tons, unless otherwise noted)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Production 1/																											
Appalachia	391	397	394	381	374	376	365	354	359	350	331	326	314	311	299	290	289	285	281	271	280	301	286	277	276	275	280
Interior	146	149	145	148	151	153	171	174	176	178	165	176	171	162	155	157	161	158	156	159	166	185	160	172	191	185	187
West	575	585	609	619	610	612	607	608	622	615	609	602	598	593	585	578	567	565	558	550	528	503	537	514	467	459	425
East of the Mississippi	485	494	490	480	476	479	482	475	483	477	448	446	431	425	410	401	400	393	387	385	398	432	403	398	408	405	410
West of the Mississippi	627	638	657	668	660	662	661	661	674	667	658	658	653	641	629	625	618	616	608	595	575	556	580	565	526	514	483
Total	1112	1131	1148	1148	1135	1141	1143	1137	1158	1144	1106	1104	1083	1066	1038	1026	1018	1009	995	981	974	988	983	963	934	919	893
Waste Coal Supplied 2/	11	13	14	14	16	17	10	14	14	14	14	14	14	14	13	13	11	12	10	10	8	9	8	7	12	12	13
Net Imports																											
Imports 3/	26	29	32	37	37	37	37	37	37	38	40	42	57	61	70	74	71	72	76	75	74	72	73	97	104	108	110
Exports	48	50	49	53	52	51	50	49	48	47	46	44	43	44	43	45	45	45	46	45	45	45	45	45	44	44	44
Total	22	21	-16	-16	-15	14	-13	-12	-11	9	-6	-2	14	17	27	29	26	27	30	30	29	28	28	52	60	64	66
Total Supply 4/	1101	1124	1146	1146	1136	1145	1140	1139	1161	1149	1114	1116	1111	1097	1078	1067	1055	1048	1035	1020	1010	1025	1019	1023	1006	995	972
Consumption by Sector																											
Residential and Commercial	5	5	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Coke Plants	24	23	24	23	22	22	22	22	21	21	21	21	20	20	20	20	20	19	19	19	19	19	19	19	18	18	18
Other Industrial 5/	62	61	64	62	63	63	64	64	60	59	59	58	58	58	57	57	57	56	56	56	56	56	55	55	55	55	55
Coal-to-Liquids Heat and Power	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Coal to Liquids Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Electric Power 6/	1016	1039	1040	1057	1046	1054	1050	1049	1074	1064	1029	1031	1027	1013	995	985	972	966	954	939	929	946	939	943	925	915	894
Total	1107	1128	1132	1146	1136	1144	1140	1139	1160	1148	1113	1114	1110	1095	1077	1066	1053	1047	1034	1019	1009	1025	1018	1021	1004	993	971
Discrepancy and Stock Change 7/	-6	-5	14	0	0	0	0	0	1	0	1	1	1	1	1	1	1	1	1	1	1	0	1	1	2	2	1
Average Minemouth Price 8/																											
(2005 dollars per short ton)	20.68	23.34	24.08	24.12	23.83	23.67	24.02	23.18	22.93	22.69	22.29	21.94	21.64	21.62	21.38	21.28	21.39	21.32	21.42	21.36	21.94	23.53	22.33	22.44	23.76	23.71	24.41
(2005 dollars per million Btu)	1.01	1.15	1.17	1.18	1.17	1.16	1.18	1.14	1.13	1.12	1.10	1.08	1.07	1.07	1.06	1.05	1.06	1.06	1.06	1.06	1.08	1.15	1.10	1.11	1.17	1.17	1.19
Delivered Prices																											
(2005 dollars per short ton) 9/																											
Coke Plants	63.36	83.79	89.37	91.14	90.55	87.70	84.89	82.14	121.37	120.88	121.96	124.58	130.56	140.57	144.96	151.08	156.03	161.28	167.35	173.51	180.39	187.55	195.38	204.07	213.18	222.92	233.40
Other Industrial 5/	40.49	47.63	47.20	48.36	48.37	48.24	48.26	47.25	75.47	77.08	78.53	80.57	83.04	85.82	88.65	91.87	95.50	99.50	103.93	108.32	113.66	119.99	125.47	131.60	138.57	145.48	153.34
Coal to Liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electric Power																											
(2005 dollars per short ton)	28.12	30.83	33.71	33.97	33.96	33.73	33.87	32.60	58.87	59.48	60.79	62.43	64.76	67.45	70.07	72.87	76.20	79.70	83.86	88.10	93.47	99.98	104.56	110.46	117.75	124.73	133.33
(2005 dollars per million Btu)	1.40	1.53	1.68	1.70	1.70	1.69	1.69	1.64	2.95	2.99	3.06	3.15	3.26	3.39	3.52	3.67	3.84	4.02	4.23	4.44	4.68	4.97	5.23	5.51	5.86	6.20	6.59
Average	29.58	32.82	35.66	35.88	35.88	35.58	35.66	34.37	60.89	61.52	62.88	64.54	66.93	69.76	72.44	75.34	78.73	82.29	86.52	90.82	96.23	102.69	107.38	113.32	120.65	127.69	136.32
Exports 10/	55.75	67.10	67.05	67.27	67.34	66.06	65.84	65.10	64.05	63.26	63.61	64.70	66.17	67.84	68.58	69.44	70.03	70.55	71.13	71.35	71.90	72.19	72.51	72.88	73.72	74.04	74.56

1/ Includes anthracite, bituminous coal, subbituminous coal, and lignite.
2/ Includes waste coal consumed by the electric power and industrial sectors. Waste coal supplied is counted as a supply-side item to balance the same amount of waste coal included in the consumption data.
3/ Excludes imports to Puerto Rico and the U.S. Virgin Islands.
4/ Production plus waste coal supplied plus net imports.
5/ Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public. Excludes all coal in the coal-to-liquids process.
6/ Includes all electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
7/ Balancing item: the sum of production, net imports, and waste coal supplied minus total consumption.
8/ Includes reported prices for both open market and captive mines.
9/ Prices weighted by consumption; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
10/ F.A.S. price at U.S. port of exit.
N/A = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
Sources: 2004 and 2005 data based on: Energy Information Administration (EIA), Annual Coal Report 2005, DOE/EIA-0584(2005) (Washington, DC, October 2006); EIA, Quarterly Coal Report, October-December 2005, DOE/EIA-0121(2005/4Q) (Washington, DC, March 2006); and EIA, AEO2007 National Energy Modeling System run s280base.d060107a.
Projections: EIA, AEO2007 National Energy Modeling System run s280nucbio.d092807a.

HEARING EXHIBIT 2008-1-2

Table 15. Coal Supply, Disposition, and Prices
(million short tons, unless otherwise noted)

Attachment POD-1 g Table 15 Coal Supply, Disposition, and Prices S 280 - RefNBLNG+noCCS Case

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Production 1/																											
Appalachia	391	397	393	380	373	372	359	348	356	346	320	310	304	297	284	279	276	270	270	264	258	253	253	256	259	263	262
Interior	146	149	145	148	152	155	170	174	175	179	145	164	159	159	146	147	143	143	138	135	129	131	130	139	142	162	165
West	575	585	609	620	609	610	603	602	615	608	577	564	568	557	552	540	525	522	516	510	494	465	460	437	403	359	326
East of the Mississippi	485	494	490	480	475	476	476	469	477	469	425	423	417	405	387	383	375	369	366	358	350	346	346	355	363	381	380
West of the Mississippi	627	638	657	668	660	662	657	655	669	664	617	615	614	608	594	583	569	566	558	551	532	504	497	477	442	403	373
Total	1112	1131	1148	1148	1135	1138	1133	1124	1146	1133	1042	1038	1032	1013	981	966	944	935	924	909	882	849	844	832	804	784	753
Waste Coal Supplied 2/	11	13	14	14	16	17	12	16	15	13	14	15	14	14	12	11	11	11	10	10	7	8	8	9	9	9	9
Net Imports																											
Imports 3/	26	29	32	37	37	37	37	37	37	38	52	52	52	61	72	73	72	68	66	66	73	70	70	72	73	71	71
Exports	48	50	49	53	52	51	50	49	48	47	46	45	44	43	43	44	45	45	45	45	45	45	44	44	44	44	43
Total	-22	-21	-16	-16	-15	-14	-13	-12	-11	-9	6	7	8	18	29	29	28	23	21	21	28	25	26	28	29	27	28
Total Supply 4/	1101	1124	1145	1147	1136	1141	1132	1128	1149	1137	1061	1059	1053	1045	1022	1006	983	969	956	940	916	883	878	869	842	820	790
Consumption by Sector																											
Residential and Commercial	5	5	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Coke Plants	24	23	24	23	22	22	22	22	21	21	21	20	20	20	20	19	19	19	19	19	19	18	18	18	18	18	17
Other Industrial 5/	62	61	64	62	63	63	63	64	60	59	58	58	57	57	57	56	56	56	56	56	55	55	55	55	55	55	55
Coal-to-Liquids Heat and Power	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Coal to Liquids Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Electric Power 6/	1016	1039	1039	1058	1046	1050	1042	1038	1063	1052	977	975	969	962	940	923	902	888	875	859	837	803	799	791	765	743	712
Total	1107	1128	1131	1146	1136	1140	1132	1128	1149	1136	1060	1058	1052	1043	1021	1004	982	967	955	938	915	881	877	868	842	820	788
Discrepancy and Stock Change 7/	-6	-5	14	0	0	0	0	0	1	1	1	2	2	1	1	2	1	1	1	1	1	1	1	1	0	0	1
Average Minemouth Price 8/																											
(2005 dollars per short ton)	20.68	23.34	24.11	24.11	23.84	23.59	23.64	23.06	22.84	22.69	22.23	21.82	21.60	21.46	21.27	21.36	21.37	21.22	21.33	21.22	21.29	21.67	21.72	22.08	22.83	24.60	25.30
(2005 dollars per million Btu)	1.01	1.15	1.17	1.18	1.17	1.16	1.16	1.13	1.12	1.12	1.09	1.07	1.06	1.06	1.05	1.08	1.05	1.05	1.05	1.05	1.05	1.07	1.07	1.08	1.11	1.18	1.21
Delivered Prices																											
(2005 dollars per short ton) 9/																											
Coke Plants	63.36	83.79	89.51	91.22	90.55	87.68	84.93	82.18	125.47	127.27	126.42	139.52	144.57	149.29	155.82	160.96	166.77	172.96	179.80	186.85	194.72	203.02	212.04	221.83	232.41	243.69	255.82
Other Industrial 5/	40.49	47.63	47.20	48.34	48.38	48.19	48.35	47.13	78.11	80.83	83.23	85.81	88.69	91.80	95.24	99.21	103.31	107.77	112.75	117.95	123.76	130.17	137.00	144.42	152.54	159.68	168.81
Coal to Liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electric Power																											
(2005 dollars per short ton)	28.12	30.83	33.74	33.97	33.96	33.64	33.39	32.44	61.43	63.31	65.67	67.50	70.23	73.06	76.47	80.08	83.84	87.86	92.60	97.44	103.35	109.52	116.06	123.49	132.40	142.31	152.15
(2005 dollars per million Btu)	1.40	1.53	1.68	1.70	1.70	1.69	1.67	1.63	3.08	3.18	3.29	3.40	3.53	3.68	3.84	4.02	4.21	4.42	4.66	4.91	5.18	5.48	5.80	6.14	6.52	6.95	7.39
Average	29.58	32.82	35.69	35.89	35.89	35.50	35.24	34.24	63.49	65.41	67.86	69.90	72.67	75.54	79.05	82.74	86.59	90.71	95.52	100.45	106.45	112.78	119.39	126.88	135.85	145.67	155.60
Exports 10/	55.75	67.10	67.16	67.31	67.34	65.97	65.86	65.05	64.02	63.19	63.66	65.33	66.78	68.26	69.14	70.01	70.59	71.09	71.59	71.64	72.10	72.25	72.64	73.08	73.55	74.05	74.55

1/ Includes anthracite, bituminous coal, subbituminous coal, and lignite.
2/ Includes waste coal consumed by the electric power and industrial sectors. Waste coal supplied is counted as a supply-side item to balance the same amount of waste coal included in the consumption data.
3/ Excludes imports to Puerto Rico and the U.S. Virgin Islands.
4/ Production plus waste coal supplied plus net imports.
5/ Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public. Excludes all coal in the coal-to-liquids process.
6/ Includes all electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
7/ Balancing item: the sum of production, net imports, and waste coal supplied minus total consumption.
8/ Includes reported prices for both open market and captive mines.
9/ Prices weighted by consumption; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
10/ F.a.s. price at U.S. port of exit.
N/A = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
Sources: 2004 and 2005 data based on: Energy Information Administration (EIA), Annual Coal Report 2005, DOE/EIA-0584(2005) (Washington, DC, October 2006); EIA, Quarterly Coal Report, October-December 2005, DOE/EIA-0121(2005/4Q) (Washington, DC, March 2006); and EIA, AEO2007 National Energy Modeling System run s280base d060107a.
Projections: EIA, AEO2007 National Energy Modeling System run s280gas d100107a.

UPA DRAFT EXHIBIT

Attachment POD-1.h. Table 21 Greenhouse Gas Emission Results

Cases:

Reference
Core S.280
No International S.280
Fixed 30% Offset S.280
No Nuclear S.280
Low Discount S.280
Unlimited Offset S.280
High Auction S.280
Commercial Covered S.280
High Technology S.280
Ref NB S.280
Ref NB+noCCS S.280
Ref NBLNG+noCCS S.280

HEARING EXHIBIT 000000

Table 21 Greenhouse Gas Emissions Results
(2005 dollars per million Btu)
(million metric tons carbon dioxide equivalent)

Attachment POD-1.h Table 21 Greenhouse Gas Emission Results S 280 - Reference Case

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Allowance Price																											
Emission Price (2005 dollars per ton)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Emission Price (nominal dollars per ton)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Offset Price (2005 dollars per ton)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Greenhouse Gas Emissions Cap Compliance																											
Covered Energy-Related Carbon Dioxide	5220.57	5241.59	5250.50	5260.52	5300.84	5360.13	5439.42	5519.30	5582.59	5643.06	5718.35	5772.65	5829.56	5878.88	5931.84	6001.45	6089.51	6181.84	6273.76	6360.02	6457.26	6551.19	6659.88	6764.31	6867.30	6962.90	7064.15
Covered Other Greenhouse Gas Emissions	317.22	323.16	336.98	347.74	361.03	374.04	387.73	401.37	412.88	425.03	437.57	450.92	464.74	478.57	492.84	508.05	524.22	540.77	557.89	575.37	593.57	612.79	632.74	653.47	674.75	696.46	719.17
Offsets Purchased	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Noncovered Gases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Domestic Agriculture/Forestry Sequestration	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
International Offsets	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Covered Emissions Less Offsets	5537.79	5564.74	5587.48	5608.26	5661.87	5734.18	5827.14	5920.67	5995.47	6068.09	6155.92	6223.57	6294.30	6357.45	6424.67	6509.51	6613.74	6722.61	6831.65	6935.40	7050.82	7163.97	7292.61	7417.78	7542.05	7659.36	7783.32
Covered Emissions Goal	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Allowance Banking (borrowing)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Cumulative Bank Balance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Energy-Related Carbon Dioxide Emissions	5923.13	5945.32	5938.86	5973.36	6023.40	6089.02	6175.66	6263.97	6335.52	6402.79	6482.98	6542.31	6604.42	6655.41	6712.17	6785.72	6879.32	6974.44	7069.03	7158.20	7259.39	7356.53	7469.71	7578.07	7684.80	7782.51	7887.71
Total Other Greenhouse Gases	1181.36	1201.97	1220.48	1236.07	1254.34	1272.47	1291.43	1309.99	1327.42	1345.59	1364.26	1383.85	1405.39	1427.08	1449.35	1472.72	1497.19	1522.20	1547.93	1574.19	1601.32	1629.65	1658.88	1689.07	1720.00	1751.53	1784.26
Total GHG Emissions	7104.50	7147.29	7159.34	7209.43	7277.74	7361.50	7467.09	7573.96	7662.94	7748.38	7847.24	7926.16	8009.81	8082.48	8161.52	8258.43	8376.51	8496.64	8616.96	8732.39	8860.71	8986.18	9128.59	9267.14	9404.79	9534.04	9671.96
Other Greenhouse Gases																											
(million metric tons)																											
Baseline Emissions Assumed																											
Methane	606.54	611.87	617.10	622.42	627.85	633.39	639.03	643.08	647.23	651.48	655.84	660.30	666.73	673.29	680.00	686.84	693.82	700.96	708.24	715.68	723.27	731.03	738.95	747.04	755.31	763.75	772.38
Landfills	148.85	155.73	155.87	156.01	156.14	156.28	156.42	157.00	157.57	158.15	158.73	159.31	160.11	160.93	161.74	162.56	163.38	164.21	165.04	165.88	166.72	167.57	168.42	169.27	170.13	170.99	171.85
Coal Mines	67.34	65.52	66.30	67.09	67.89	68.70	69.52	69.14	68.76	68.39	68.02	67.65	68.16	68.68	69.20	69.73	70.26	70.79	71.33	71.87	72.42	72.97	73.53	74.08	74.65	75.22	75.79
Natural Gas	154.75	154.05	157.77	161.58	165.48	169.47	173.56	177.63	181.79	186.05	190.41	194.87	199.82	204.89	210.08	215.41	220.88	226.48	232.22	238.11	244.15	250.35	256.70	263.21	269.88	276.73	283.75
Other	235.61	236.58	237.16	237.75	238.35	238.94	239.53	239.32	239.11	238.89	238.68	238.47	238.64	238.80	238.97	239.14	239.31	239.47	239.64	239.81	239.98	240.14	240.31	240.48	240.65	240.82	240.99
Non-Energy Carbon Dioxide	65.47	63.33	66.32	65.64	66.85	67.09	67.28	67.86	68.67	69.61	70.39	71.42	72.60	73.27	73.84	74.79	76.11	77.21	78.24	78.97	79.72	80.78	81.81	82.84	83.60	83.94	84.39
Nitrous Oxide	359.87	366.56	367.06	367.62	368.23	368.89	369.61	370.38	372.05	373.72	375.41	377.10	379.19	381.30	383.42	385.56	387.71	389.87	392.05	394.24	396.44	398.66	400.89	403.13	405.39	407.67	409.96
Agriculture	272.89	279.87	281.62	283.38	285.15	286.93	288.72	290.52	291.72	292.93	294.15	295.37	296.71	298.06	299.42	300.79	302.16	303.53	304.91	306.30	307.70	309.10	310.51	311.92	313.34	314.77	316.20
Mobile Combustion	52.05	52.59	51.08	49.62	48.19	46.81	45.47	44.16	44.35	44.53	44.72	44.91	45.36	45.83	46.30	46.77	47.25	47.73	48.22	48.71	49.21	49.71	50.22	50.73	51.25	51.77	52.30
Other	34.94	34.09	34.36	34.62	34.89	35.15	35.42	35.70	35.97	36.26	36.54	36.82	37.12	37.41	37.71	38.01	38.31	38.61	38.92	39.23	39.54	39.85	40.17	40.49	40.81	41.13	41.46
High GWP Gases	149.48	160.22	170.00	180.39	191.41	203.10	215.51	228.68	239.47	250.78	262.62	275.03	286.87	299.21	312.09	325.53	339.54	354.16	369.40	385.31	401.89	419.19	437.24	456.06	475.69	496.17	517.53
Total Baseline	1181.36	1201.97	1220.48	1236.07	1254.34	1272.47	1291.43	1309.99	1327.42	1345.59	1364.26	1383.84	1405.39	1427.08	1449.35	1472.72	1497.19	1522.20	1547.93	1574.19	1601.32	1629.65	1658.88	1689.07	1720.00	1751.53	1784.26
Abatement and Offsets																											
Methane	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Landfills	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Coal Mines	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Natural Gas	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Other	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Non-Energy Carbon Dioxide	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Nitrous Oxide	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Agriculture	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Mobile Combustion	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Other	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
High GWP Gases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Reductions	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Resulting Emissions																											
Methane	606.54	611.87	617.10	622.42	627.85	633.39	639.03	643.08	647.23	651.48	655.84	660.30	666.73	673.29	680.00	686.84	693.82	700.96	708.24	715.68	723.27	731.03	738.95	747.04	755.31	763.75	772.38
Landfills	148.85	155.73	155.87	156.01	156.14	156.28	156.42	157.00	157.57	158.15	158.73	159.31	160.11	160.93	161.74	162.56	163.38	164.21	165.04	165.88	166.72	167.57	168.42	169.27	170.13	170.99	171.85
Coal Mines	67.34	65.52	66.30	67.09	67.89	68.70	69.52	69.14	68.76	68.39	68.02	67.65	68.16	68.68	69.20	69.73	70.26	70.79	71.33	71.87	72.42	72.97	73.53	74.08	74.65	75.22	75.79
Natural Gas	154.75	154.05	157.77	161.58	165.48	169.47	173.56	177.63	181.79	186.05	190.41	194.87	199.82	204.89	210.08	215.41	220.88	226.48	232.22	238.11	244.15	250.35	256.70	263.21	269.88	276.73	283.75
Other	235.61	236.58	237.16	237.75	238.35	238.94	239.53	239.32	239.11	238.89	238.68	238.47	238.64	238.80	238.97	239.14	239.31	239.47	239.64	239.81	239.98	240.14	240.31	240.48	240.65	240.82	240.99
Non-Energy Carbon Dioxide	65.47	63.33	66.32	65.64	66.85	67.09	67.28	67.86	68.67	69.61	70.39	71.42	72.60	73.27	73.84	74.79	76.11	77.21	78.24	78.97	79.72	80.78	81.81	82.84	83.60	83.94	84.39
Nitrous Oxide	359.87	366.56	367.06	367.62	368.23	368.89	369.61	370.38	372.05	373.72	375.41	377.10	379.19	381.30	383.42	385.56	387.71	389.87	392.05	394.24	396.44	398.66	400.89	403.13	405.39	407.67	409.96
Agriculture	272.89	279.87	281.62	283.38	285.15	286.93	288.72	290.52	291.72	292.93	294.15	295.37	296.71	298.06	299.42	300.79	302.16	303.53	304.91	306.30	307.70	309.10	310.51	311.92	313.34	314.77	316.20
Mobile Combustion	52.05	52.59	51.08	49.62	48.19	46.81	45.47	44.16	44.35	44.53	44.72	44.91	45.36	45.83	46.30	46.77	47.25	47.73	48.22	48.71	49.21	49.71	50.22	50.73	51.25	51.77	52.30
Other	34.94	34.09	34.36	34.62	34.89	35.15	35.42	35.70	35.97	36.26	36.54	36.82	37.12	37.41	37.71	38.01	38.31	38.61	38.92	39.23	39.54	39.85	40.17	40.49	40.81	41.13	41.46
High GWP Gases	149.48	160.22	170.00	180.39	191.41	203.10	215.51	228.68	239.47	250.78	262.62	275.03	286.87	299.21	312.09	325.53	339.54	354.16	369.40	385.31	401.89	419.19	437.24	456.06	475.69	496.17	517.53
Total Other Greenhouse Gas Emissions	1181.36	1201.97	1220.48	1236.07	1254.34	1272.47	1291.43	1309.99	1327.42	1345.59	1364.26	1383.84	1405.39	1427.08	1449.35	1472.72	1497.19	1522.20	1547.93	1574.19	1601.32	1629.65	1658.88	1689.07	1720.00	1751.53	1784.26

Note: Totals may not equal sum of components due to independent rounding. Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
N/A = Not applicable.
Sources: 2004 and 2005 emissions and emission factors: Energy Information Administration (EIA), Emissions of Greenhouse Gases in the United States 2005, DOE/EIA-0573(2005) (Washington, DC, November 2006). Projections: EIA, AEO2007 National Energy Modeling System run s280base.d060107a.

HEARING EXHIBIT 00000000

Table 21 Greenhouse Gas Emissions Results
(2005 dollars per million Btu)
(million metric tons carbon dioxide equivalent)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Allowance Price																											
Emission Price (2005 dollars per	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	18.00	17.88	19.31	20.86	22.53	24.33	26.27	28.38	10.65	33.10	35.74	38.60	36.29	39.19	42.32	45.71	49.37	53.32	57.58
Emission Price (nominal dollars p	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	20.83	21.11	23.20	25.52	28.09	30.90	34.00	37.45	41.23	45.45	50.13	55.24	52.97	58.40	64.39	71.02	78.33	86.30	95.16
Offset Price (2005 dollars per to	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	18.00	17.88	19.31	20.86	22.53	24.33	26.27	28.38	30.65	33.10	35.74	38.60	36.29	39.19	42.32	45.71	49.37	53.32	41.84
Greenhouse Gas Emissions Cap Compliance																											
Covered Energy-Related Carbon Dioxid	5220.57	5241.59	5242.95	5254.54	5192.92	5202.50	5227.27	5254.09	5258.38	5259.75	5274.59	5269.25	5254.74	5220.28	5191.44	5144.59	5091.51	5017.18	4949.74	4839.65	4806.42	4726.11	4603.31	4471.31	4387.39	4307.13	4173.88
Covered Other Greenhouse Gas Emissio	317.22	323.16	334.21	342.07	352.37	362.34	372.67	383.78	342.76	348.11	352.48	357.03	360.77	365.23	370.10	375.77	382.20	395.85	410.46	425.91	444.21	461.75	480.59	500.43	521.26	542.87	565.24
Offsets Purchased	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	173.03	185.12	214.81	248.58	293.01	342.31	399.03	464.04	538.22	616.18	704.13	802.93	788.27	895.29	970.99	1049.60	1130.89	1215.40	963.50
Noncovered Gases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	52.62	56.38	64.99	74.75	84.50	91.59	98.93	106.59	114.56	120.21	126.07	132.04	130.72	136.42	138.54	140.69	142.80	144.94	133.91
Domestic Agriculture/Forestry Sequ	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	120.41	128.74	149.82	173.83	208.51	250.72	300.11	357.45	423.66	495.97	578.05	670.90	657.55	758.88	832.45	908.91	988.09	1070.46	829.59
International Offsets	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Covered Emissions Less Offsets	5537.79	5564.74	5577.16	5596.61	5545.29	5564.84	5599.94	5637.87	5428.11	5422.74	5412.27	5377.71	5322.51	5243.21	5162.51	5056.32	4935.49	4796.84	4656.08	4462.63	4462.36	4292.56	4212.91	3922.14	3777.76	3634.61	3775.62
Covered Emissions Goal	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	5428.87	5428.87	5428.87	5428.87	5428.87	5428.87	5428.87	5428.87	4460.50	4460.50	4460.50	4460.50	4460.50	4460.50	4460.50	4460.50	4460.50	4460.50	3209.43
Allowance Banking (borrowing)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.76	6.13	16.60	51.16	106.35	185.66	266.36	372.54	-474.99	-336.34	-195.58	-2.13	-1.86	167.94	347.59	538.36	682.74	825.89	-566.19
Cumulative Bank Balance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.76	6.89	23.49	74.65	181.00	366.66	633.02	1005.56	530.58	194.24	-1.34	-3.47	-5.33	162.61	510.20	1048.56	1731.30	2557.20	1991.01
Total Energy-Related Carbon Dioxide Em	5923.13	5945.32	5931.31	5967.40	5915.21	5931.38	5962.06	5995.59	6007.75	6016.00	6036.20	6035.35	6025.81	5993.30	5968.51	5925.49	5878.00	5805.46	5740.43	5632.77	5604.16	5526.58	5407.48	5277.90	5197.85	5122.12	4994.72
Total Other Greenhouse Gases	1181.36	1201.97	1216.01	1227.01	1240.57	1253.95	1267.84	1281.88	1192.12	1197.64	1197.40	1196.25	1195.38	1197.95	1200.76	1204.12	1208.00	1221.51	1235.83	1250.97	1276.32	1293.97	1316.58	1340.25	1365.02	1390.64	1430.27
Total GHG Emissions	7104.50	7147.29	7147.32	7194.41	7155.78	7185.33	7229.89	7277.47	7199.87	7213.65	7233.60	7231.60	7221.18	7191.26	7169.28	7129.61	7086.00	7026.97	6976.26	6883.75	6880.47	6820.55	6724.07	6618.15	6562.87	6512.75	6424.99
Other Greenhouse Gases																											
(million metric tons)																											
Baseline Emissions Assumed																											
Methane	606.54	611.87	613.58	615.40	617.32	619.35	621.48	622.77	624.14	625.58	627.09	628.68	632.01	635.40	638.85	642.37	645.94	649.58	653.28	657.05	660.88	664.78	668.76	672.80	676.91	681.10	685.36
Landfills	148.85	155.73	154.48	153.24	152.01	150.79	149.59	149.28	148.97	148.67	148.36	148.06	147.91	147.75	147.60	147.45	147.30	147.14	146.99	146.84	146.69	146.54	146.39	146.23	146.08	145.93	145.78
Coal Mines	67.34	65.52	64.48	63.46	62.46	61.47	60.50	59.36	58.23	57.13	56.06	55.00	54.99	54.99	54.98	54.98	54.97	54.97	54.96	54.96	54.95	54.95	54.94	54.94	54.93	54.93	54.92
Natural Gas	154.75	154.05	157.46	160.94	164.50	168.14	171.87	174.82	177.83	180.88	183.99	187.16	190.48	193.86	197.30	200.80	204.37	207.99	211.68	215.44	219.26	223.16	227.12	231.15	235.25	239.42	243.67
Other	235.61	236.58	237.16	237.75	238.35	238.94	239.53	239.32	239.11	238.89	238.68	238.47	238.64	238.80	238.97	239.14	239.31	239.47	239.64	239.81	239.98	240.14	240.31	240.48	240.65	240.82	240.99
Non-Energy Carbon Dioxide	65.47	63.33	66.32	65.63	66.84	67.16	67.25	67.68	65.92	66.56	67.15	67.85	68.70	69.09	69.37	69.90	70.58	70.99	71.49	71.87	72.85	73.44	73.68	74.04	74.35	74.48	74.30
Nitrous Oxide	359.87	366.56	367.06	367.62	368.23	368.89	369.61	370.38	372.05	373.72	375.41	377.10	379.19	381.30	383.42	385.56	387.71	389.87	392.05	394.24	396.44	398.66	400.89	403.13	405.39	407.67	409.96
Agriculture	272.89	279.87	281.62	283.38	285.15	286.93	288.72	290.52	291.72	292.93	294.15	295.37	296.71	298.06	299.42	300.79	302.16	303.53	304.91	306.30	307.70	309.10	310.51	311.92	313.34	314.77	316.20
Mobile Combustion	52.05	52.59	51.08	49.62	48.19	46.81	45.47	44.16	44.35	44.53	44.72	44.91	45.36	45.83	46.30	46.77	47.25	47.73	48.22	48.71	49.21	49.71	50.22	50.73	51.25	51.77	52.30
Other	34.94	34.09	34.36	34.62	34.89	35.15	35.42	35.70	35.97	36.26	36.54	36.82	37.12	37.41	37.71	38.01	38.31	38.61	38.92	39.23	39.54	39.85	40.17	40.49	40.81	41.13	41.46
High GWP Gases	149.48	160.22	169.04	178.36	188.19	198.56	209.50	221.04	232.54	244.64	257.36	270.75	282.84	295.47	308.66	322.45	336.85	351.89	367.60	384.02	401.17	419.08	437.80	457.35	477.77	499.10	521.39
Total Baseline	1181.36	1201.97	1216.01	1227.01	1240.57	1253.95	1267.84	1281.88	1294.65	1310.50	1327.01	1344.38	1362.75	1381.27	1400.31	1420.28	1441.08	1462.33	1484.42	1507.17	1531.33	1555.96	1581.12	1607.32	1634.42	1662.35	1691.01
Abatement and Offsets																											
Methane	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	62.47	66.82	75.81	85.94	95.17	101.42	107.71	114.10	120.54	124.32	128.06	131.64	130.82	133.92	134.89	135.78	136.50	137.14	133.75
Landfills	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	34.29	36.65	41.98	47.99	53.44	56.29	59.05	61.75	64.35	65.45	66.44	67.28	67.39	68.03	68.22	68.37	68.45	68.50	68.46
Coal Mines	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	18.36	19.55	21.17	22.92	24.11	25.16	26.18	27.17	28.10	28.58	29.01	29.38	29.43	29.71	29.79	29.86	29.89	29.92	29.93
Natural Gas	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	6.92	7.52	9.05	10.82	12.65	14.15	15.73	17.42	19.21	20.31	21.45	22.53	21.92	22.79	22.85	22.90	22.93	22.96	22.93
Other	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	2.90	3.09	3.62	4.21	4.96	5.81	6.74	7.76	8.89	9.98	11.17	12.44	12.07	13.39	14.04	14.65	15.23	15.76	12.44
Non-Energy Carbon Dioxide	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nitrous Oxide	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	18.17	19.63	21.95	24.50	27.23	30.07	33.07	36.26	39.63	42.28	45.10	48.08	47.67	50.72	52.00	53.38	54.82	56.36	48.74
Agriculture	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	8.51	9.12	10.35	11.72	13.44	15.33	17.40	19.66	22.12	24.47	27.02	29.78	29.34	32.21	33.44	34.77	36.19	37.72	30.09
Mobile Combustion	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	9.66	10.51	11.60	12.77	13.79	14.73	15.67	16.60	17.51	17.81	18.08	18.31	18.34	18.51	18.56	18.60	18.63	18.64	18.65
High GWP Gases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	21.89	26.40	31.85	37.69	44.97	51.83	58.76	65.80	72.90	74.22	75.43	76.47	76.53	77.35	77.65	77.92	78.08	78.21	78.26
Total Reductions	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	102.53	112.85	129.62	148.13	167.37	183.31	199.54	216.16	233.07	240.82	248.59	256.20	255.02	261.98	264.54	267.07	269.40	271.71	260.74
Resulting Emissions																											
Methane	606.54	611.87	613.58	615.40	617.32	619.35	621.48	622.77	561.67	558.76	551.28	542.74	536.84	533.99	531.14	528.26	525.40	525.26	525.22	525.41	530.06	530.86	533.87	537.02	540.41	543.96	551.62
Landfills	148.85	155.73	154.48	153.24	152.01	150.79	149.59	149.28	114.68	112.02	106.39	100.07	94.46	91.46	88.55	85.70	82.95	81.70	80.55	79.56	79.30	78.50	78.17	77.86	77.63	77.43	77.32
Coal Mines	67.34	65.52	64.48	63.46	62.46	61.47	60.50	59.36	39.87	37.58	34.88	32.07	30.88	29.82	28.80	27.81	26.87	26.39	25.95	25.58	25.52	25.24	25.15	25.08	25.04	25.01	25.00
Natural Gas	154.75	154.05	157.46	160.94	164.50	168.14	171.87	174.82	170.90	173.37	174.94	176.34	177.82	179.71	181.57	183.38	185.16	187.68	190.24	192.91	197.34	200.37	204.27	208.25	212.32	216.46	220.75
Other	235.61	236.58	237.16	237.75	238.35	238.94	239.53	239.32	236.21	235.80	235.06	234.26	233.68	232.99	232.23	231.37	230.42	229.49	228.47	227.37	227.91	226.76	226.28	225.83	225.42	225.06	228.55
Non-Energy Carbon Dioxide	65.47	63.33	66.32	65.63	66.84	67.16	67.25	67.68	65.92	66.56	67.15	67.85	68.70	69.09	69.37	69.90	70.58	70.99	71.49	71.87	72.85	73.44	73.68	74.04	74.35	74.48	74.30
Nitrous Oxide	359.87	366.56	367.06	367.62	368.23	368.89	369.61	370.38	353.88	354.09	353.45	352.60	351.97	351.23	350.35	349.30	348.08	347.59	346.95	346.15	348.77	347.94	348.89	349.76	350.58	351.31	361.22
Agriculture	272.89	279.87	281.62	283.38	285.15	286.93	288.72	290.52	283.21	283.81	283.80	283.64	283.28	282.73	282.02	281.13	280.04	279.06	277.89	276.53	278.36	276.89	277.07	277.15	277.15	277.05	286.11
Mobile Combustion	52.05	52.59	51.08	49.62	48.19	46.81	45.47	44.16	44.35	44.53	44.72	44.91	45.36	45.83	46.30	46.77	47.25	47.73	48.22	48.71	49.21	49.71	50.22	50.73	51.25	51.77	52.30
Other	34.94	34.09	34.36	34.62	34.89	35.15	35.42	35.70	26.31	25.74	24.93	24.05	23.33	22.67	22.03	21.41	20.80	20.80	20.84	20.92	21.20	21.34	21.61	21.88	22.18	22.49	22.81
High GWP Gases	149.48	160.22	169.04	178.36	188.19	198.56	209.50	221.04	210.65	218.23	225.51	233.05	237.87	243.64	249.90	256.65	263.94	277.66	292.18	307.55	324.64	341.74	360.15	379.42	399.69	420.89	443.13
Total Other Greenhouse Gas Emissio	1181.36	1201.97	1216.01	1227.01	1240.57	1253.95	1267.84	1281.88	1192.12	1197.64	1197.40	1196.25	1195.38	1197.95	1200.76	1204.12	1208.00	1221.51	1235.83	1250.97	1276.32	1293.97	1316.58	1340.25	1365.02	1390.64	1430.27

Note: Totals may not equal sum of components due to independent rounding. Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
N/A = Not applicable.
Sources: 2004 and 2005 emissions and emission factors: Energy Information Administration (EIA), Emissions of Greenhouse Gases in the United States 2005, DOE/EIA-0573(2005) (Washington, DC, November 2006). Projections: EIA, AEO2007 National Energy Modeling System run s280noint1.d061507a.

HEARING EXHIBIT 00000000

Table 21. Greenhouse Gas Emissions Results
(2005 dollars per million Btu)
(million metric tons carbon dioxide equivalent)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Allowance Price																											
Emission Price (2005 dollars per	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	7.76	8.38	9.06	9.78	10.56	11.41	12.32	13.31	14.37	15.52	16.76	18.10	19.55	21.11	22.80	24.63	26.60	28.73	31.02
Emission Price (nominal dollars p	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	8.96	9.86	10.83	11.89	13.07	14.37	15.80	17.39	19.12	21.05	23.20	25.56	28.18	31.07	34.23	37.75	41.62	45.85	50.55
Offset Price (2005 dollars per to	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	7.76	8.38	9.06	9.78	10.56	11.41	12.32	13.31	14.37	15.52	16.76	18.10	19.55	21.11	22.80	24.63	26.60	28.73	31.02
Greenhouse Gas Emissions Cap Compliance																											
Covered Energy-Related Carbon Dioxid	5220.57	5241.59	5245.28	5258.71	5266.26	5297.62	5349.88	5392.94	5402.79	5426.59	5462.71	5469.63	5494.61	5520.70	5538.21	5552.26	5567.82	5563.41	5575.25	5596.54	5613.73	5631.59	5646.81	5652.89	5652.26	5642.74	5634.91
Covered Other Greenhouse Gas Emissio	317.22	323.16	334.21	342.08	352.40	362.30	372.69	383.82	355.85	362.91	370.17	377.86	384.15	389.70	395.19	400.80	406.52	416.31	428.32	441.53	455.62	470.74	487.98	507.21	527.39	548.32	570.27
Offsets Purchased	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1628.66	1628.66	1628.66	1628.66	1628.66	1628.66	1628.66	1628.66	1628.66	1338.15	1338.15	1338.15	1338.15	1338.15	1338.15	1338.15	1338.15	1338.15	962.83
Noncovered Gases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	36.86	41.13	45.80	49.40	53.18	57.20	61.48	65.94	70.66	74.62	81.15	88.80	96.96	105.66	111.93	114.51	117.09	119.67	122.16
Domestic Agriculture/Forestry Sequ	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	56.35	63.52	71.57	81.04	89.48	100.62	114.77	133.16	155.60	180.87	212.03	248.85	291.62	340.96	390.14	441.09	493.68	548.00	603.99
International Offsets	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1535.45	1524.01	1511.29	1498.22	1486.00	1470.85	1452.41	1429.56	1111.89	1082.66	1044.96	1000.50	949.58	891.53	836.08	782.56	727.38	670.48	236.67
Covered Emissions Less Offsets	5537.79	5564.74	5579.49	5600.79	5618.65	5659.92	5722.57	5776.76	4129.99	4160.84	4204.22	4218.83	4250.10	4281.74	4304.74	4324.41	4636.19	4641.57	4665.42	4699.92	4731.20	4764.18	4796.64	4821.95	4841.50	4852.91	5242.35
Covered Emissions Goal	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	5428.87	5428.87	5428.87	5428.87	5428.87	5428.87	5428.87	5428.87	4460.50	4460.50	4460.50	4460.50	4460.50	4460.50	4460.50	4460.50	4460.50	4460.50	3209.43
Allowance Banking (borrowing)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1298.88	1268.02	1224.65	1210.03	1178.77	1147.12	1124.13	1104.46	-175.69	-181.07	-204.92	-239.42	-270.70	-303.68	-336.14	-361.45	-381.00	-392.41	-2032.91
Cumulative Bank Balance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1298.88	2566.90	3791.55	5001.58	6180.35	7327.48	8451.60	9556.06	9380.37	9199.30	8994.39	8754.97	8484.27	8180.59	7844.45	7483.00	7101.99	6709.58	4676.66
Total Energy-Related Carbon Dioxide Em	5923.13	5945.32	5933.64	5971.58	5988.77	6026.49	6085.18	6136.02	6153.56	6183.95	6224.53	6235.71	6265.21	6292.31	6313.14	6330.61	6350.51	6347.65	6360.93	6384.29	6404.45	6424.40	6443.16	6452.34	6455.51	6449.13	6446.27
Total Other Greenhouse Gases	1181.36	1201.97	1216.01	1227.01	1240.60	1253.92	1267.86	1281.93	1220.97	1227.69	1234.28	1242.42	1250.07	1256.82	1263.30	1269.81	1276.22	1287.56	1298.61	1309.83	1321.50	1333.73	1350.59	1373.21	1396.87	1421.37	1447.04
Total GHG Emissions	7104.50	7147.29	7149.65	7198.59	7229.37	7280.41	7353.03	7417.94	7374.54	7411.64	7458.81	7478.13	7515.28	7549.12	7576.44	7600.42	7626.73	7635.21	7659.54	7694.11	7725.95	7758.13	7793.74	7825.55	7852.38	7870.50	7893.31
Other Greenhouse Gases																											
(million metric tons)																											
Baseline Emissions Assumed																											
Methane	606.54	611.87	613.58	615.40	617.32	619.35	621.48	622.77	624.14	625.58	627.09	628.68	632.01	635.40	638.85	642.37	645.94	649.58	653.28	657.05	660.88	664.78	668.76	672.80	676.91	681.10	685.36
Landfills	148.85	155.73	154.48	153.24	152.01	150.79	149.59	149.28	148.97	148.67	148.36	148.06	147.91	147.75	147.60	147.45	147.30	147.14	146.99	146.84	146.69	146.54	146.39	146.23	146.08	145.93	145.78
Coal Mines	67.34	65.52	64.48	63.46	62.46	61.47	60.50	59.36	58.23	57.13	56.06	55.00	54.99	54.99	54.98	54.98	54.97	54.97	54.96	54.96	54.95	54.95	54.94	54.94	54.93	54.93	54.92
Natural Gas	154.75	154.05	157.46	160.94	164.50	168.14	171.87	174.82	177.83	180.88	183.99	187.16	190.48	193.86	197.30	200.80	204.37	207.99	211.68	215.44	219.26	223.16	227.12	231.15	235.25	239.42	243.67
Other	235.61	236.58	237.16	237.75	238.35	238.94	239.53	239.32	239.11	238.89	238.68	238.47	238.64	238.80	238.97	239.14	239.31	239.47	239.64	239.81	239.98	240.14	240.31	240.48	240.65	240.82	240.99
Non-Energy Carbon Dioxide	65.47	63.33	66.32	65.64	66.87	67.12	67.27	67.73	67.52	68.24	68.92	69.87	70.92	71.31	71.76	72.52	73.59	74.27	74.75	75.13	75.59	76.22	76.84	77.37	77.86	78.07	78.14
Nitrous Oxide	359.87	366.56	367.06	367.62	368.23	368.89	369.61	370.38	372.05	373.72	375.41	377.10	379.19	381.30	383.42	385.56	387.71	389.87	392.05	394.24	396.44	398.66	400.89	403.13	405.39	407.67	409.96
Agriculture	272.89	279.87	281.62	283.38	285.15	286.93	288.72	290.52	291.72	292.93	294.15	295.37	296.71	298.06	299.42	300.79	302.16	303.53	304.91	306.30	307.70	309.10	310.51	311.92	313.34	314.77	316.20
Mobile Combustion	52.05	52.59	51.08	49.62	48.19	46.81	45.47	44.16	44.35	44.53	44.72	44.91	45.36	45.83	46.30	46.77	47.25	47.73	48.22	48.71	49.21	49.71	50.22	50.73	51.25	51.77	52.30
Other	34.94	34.09	34.36	34.62	34.89	35.15	35.42	35.70	35.97	36.26	36.54	36.82	37.12	37.41	37.71	38.01	38.31	38.61	38.92	39.23	39.54	39.85	40.17	40.49	40.81	41.13	41.46
High GWP Gases	149.48	160.22	169.04	178.36	188.19	198.56	209.50	221.04	232.54	244.64	257.36	270.75	282.84	295.47	308.66	322.45	336.85	351.89	367.60	384.02	401.17	419.08	437.80	457.35	477.77	499.10	521.39
Total Baseline	1181.36	1201.97	1216.01	1227.01	1240.60	1253.92	1267.86	1281.93	1296.25	1312.18	1328.78	1346.40	1364.97	1383.49	1402.70	1422.89	1444.09	1465.60	1487.67	1510.43	1534.07	1558.74	1584.28	1610.64	1637.93	1665.94	1694.85
Abatement and Offsets																											
Methane	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	47.57	52.33	57.49	61.59	65.46	69.53	73.80	78.14	82.65	86.23	92.17	99.08	106.32	113.94	120.00	122.20	124.34	126.40	128.29
Landfills	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	25.08	28.20	31.61	33.80	35.81	37.90	40.09	42.29	44.56	46.27	49.67	53.74	58.03	62.56	66.24	66.84	67.38	67.85	68.21
Coal Mines	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	16.09	17.09	18.16	19.29	20.25	21.24	22.28	23.33	24.41	25.34	26.19	27.00	27.77	28.50	28.93	29.19	29.42	29.63	29.79
Natural Gas	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	5.13	5.60	6.09	6.63	7.21	7.82	8.46	9.07	9.70	10.07	11.14	12.49	13.94	15.49	16.91	17.74	18.62	19.55	20.48
Other	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1.27	1.44	1.63	1.86	2.20	2.57	2.98	3.45	3.98	4.54	5.17	5.85	6.58	7.38	7.92	8.43	8.91	9.37	9.80
Non-Energy Carbon Dioxide	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nitrous Oxide	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	13.82	15.07	16.40	17.85	19.55	21.36	23.31	25.39	27.63	29.53	31.49	33.55	35.71	37.98	38.89	39.68	40.51	41.36	42.23
Agriculture	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	5.37	5.89	6.46	7.10	7.96	8.91	9.96	11.13	12.42	13.74	15.17	16.73	18.41	20.22	20.86	21.49	22.17	22.90	23.67
Mobile Combustion	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	8.45	9.18	9.94	10.75	11.58	12.45	13.35	14.27	15.21	15.79	16.32	16.82	17.30	17.76	18.02	18.19	18.33	18.46	18.56
High GWP Gases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	13.88	17.09	20.60	24.54	29.89	35.78	42.28	49.55	57.59	62.30	65.39	67.98	70.55	73.09	74.81	75.55	76.22	76.81	77.30
Total Reductions	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	75.28	84.49	94.50	103.98	114.90	126.67	139.40	153.09	167.86	178.05	189.06	200.60	212.58	225.01	233.70	237.43	241.07	244.58	247.81
Resulting Emissions																											
Methane	606.54	611.87	613.58	615.40	617.32	619.35	621.48	622.77	576.57	573.25	569.60	567.10	566.55	565.87	565.05	564.22	563.29	563.35	561.10	557.97	554.56	550.85	548.76	550.59	552.57	554.70	557.08
Landfills	148.85	155.73	154.48	153.24	152.01	150.79	149.59	149.28	123.89	120.47	116.75	114.26	112.10	109.85	107.51	105.16	102.74	100.88	97.32	93.10	88.66	83.98	80.14	79.39	78.70	78.08	77.57
Coal Mines	67.34	65.52	64.48	63.46	62.46	61.47	60.50	59.36	42.14	40.04	37.90	35.70	34.75	33.75	32.70	31.65	30.57	29.63	28.77	27.96	27.18	26.44	26.01	25.75	25.51	25.30	25.13
Natural Gas	154.75	154.05	157.46	160.94	164.50	168.14	171.87	174.82	172.70	175.29	177.90	180.52	183.27	186.06	188.84	191.73	194.67	197.92	200.54	202.95	205.33	207.66	210.21	213.40	216.63	219.88	223.19
Other	235.61	236.58	237.16	237.75	238.35	238.94	239.53	239.32	237.84	237.45	237.05	236.61	236.44	236.24	235.99	235.68	235.32	234.93	234.47	233.96	233.39	232.76	232.39	232.05	231.73	231.44	231.18
Non-Energy Carbon Dioxide	65.47	63.33	66.32	65.64	66.87	67.12	67.27	67.73	67.52	68.24	68.92	69.87	70.92	71.31	71.76	72.52	73.59	74.27	74.75	75.13	75.59	76.22	76.84	77.37	77.86	78.07	78.14
Nitrous Oxide	359.87	366.56	367.06	367.62	368.23	368.89	369.61	370.38	358.22	358.66	359.00	359.24	359.65	359.94	360.12	360.17	360.08	360.34	360.55	360.69	360.73	360.68	362.00	363.45	364.89	366.31	367.73
Agriculture	272.89	279.87	281.62	283.38	285.15	286.93	288.72	290.52	286.35	287.04	287.69	288.27	288.75	289.15	289.47	289.66	289.74	289.79	289.74	289.58	289.29	288.88	289.65	290.43	291.17	291.87	292.54
Mobile Combustion	52.05	52.59	51.08	49.62	48.19	46.81	45.47	44.16	44.35	44.53	44.72	44.91	45.36	45.83	46.30	46.77	47.25	47.73	48.22	48.71	49.21	49.71	50.22	50.73	51.25	51.77	52.30
Other	34.94	34.09	34.36	34.62	34.89	35.15	35.42	35.70	27.53	27.08	26.60	26.07	25.53	24.96	24.35	23.74	23.10	22.82	22.60	22.40	22.23	22.09	22.14	22.30	22.47	22.67	22.90
High GWP Gases	149.48	160.22	169.04	178.36	188.19	198.56	209.50	221.04	218.66	227.55	236.76	246.21	252.95	259.69	266.38	272.90	279.26	289.59	302.21	316.04	330.62	345.99	362.98	381.80	401.55	422.29	444.10
Total Other Greenhouse Gas Emissio	1181.36	1201.97	1216.01	1227.01	1240.60	1253.92	1267.86	1281.93	1220.97	1227.69	1234.28	1242.42	1250.07	1256.82	1263.30	1269.81	1276.22	1287.56	1298.61	1309.83	1321.50	1333.73	1350.59	1373.21	1396.87	1421.37	1447.04

Note: Totals may not equal sum of components due to independent rounding. Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
N/A = Not applicable.
Sources: 2004 and 2005 emissions and emission factors: Energy Information Administration (EIA), Emissions of Greenhouse Gases in the United States 2005, DOE/EIA-0573(2005) (Washington, DC, November 2006). Projections: EIA, AEO2007 National Energy Modeling System run s280straw.d060207a.

HEARING EXHIBIT - 00000203

Table 21 Greenhouse Gas Emissions Results
(2005 dollars per million Btu)
(million metric tons carbon dioxide equivalent)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Allowance Price																											
Emission Price (2005 dollars per ton)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	13.14	13.78	14.76	15.94	17.22	18.60	20.08	21.69	23.43	25.30	27.32	29.51	31.87	34.42	37.17	40.15	43.36	46.83	50.58
Emission Price (nominal dollars per ton)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	15.18	16.24	17.71	19.47	21.42	23.56	25.92	28.54	31.39	34.56	38.10	41.97	46.26	51.01	56.20	61.96	68.35	75.36	83.16
Offset Price (2005 dollars per ton)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	13.14	13.78	14.76	15.94	17.22	18.60	20.08	21.69	20.86	18.75	17.20	16.02	15.10	14.34	15.52	16.74	18.00	19.28	19.48
Greenhouse Gas Emissions Cap Compliance																											
Covered Energy-Related Carbon Dioxide	5220.57	5241.59	5243.95	5254.73	5225.93	5252.57	5274.70	5309.10	5313.61	5320.65	5313.81	5332.68	5347.06	5342.36	5322.87	5304.12	5301.00	5282.66	5255.05	5219.00	5176.80	5106.00	5067.50	5013.46	4948.42	4845.36	4734.32
Covered Other Greenhouse Gas Emissions	317.22	323.16	334.21	342.05	352.36	362.30	372.69	383.84	348.53	353.87	358.74	363.80	368.47	372.73	377.09	382.05	388.28	401.39	415.29	429.96	445.90	463.17	482.06	501.97	522.59	543.78	565.97
Offsets Purchased	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	235.44	246.11	309.41	415.85	582.36	799.92	1074.17	1411.34	1337.38	1337.92	1336.70	1339.72	1339.44	1337.87	1337.26	1339.28	1339.39	1336.78	962.92
Noncovered Gases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	44.33	48.18	52.60	57.87	65.57	73.99	83.19	93.25	93.78	87.26	82.96	80.17	80.10	80.93	83.11	87.67	92.91	98.11	98.97
Domestic Agriculture/Forestry Sequestration	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	88.06	98.71	112.70	129.58	152.95	181.28	215.11	255.07	260.00	237.73	220.35	206.52	195.52	186.08	224.87	264.76	304.71	344.33	360.22
International Offsets	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	103.05	99.22	144.10	228.41	363.84	544.65	775.87	1063.02	983.61	1012.93	1033.40	1053.02	1063.82	1070.86	1029.28	986.84	941.77	894.34	503.74
Covered Emissions Less Offsets	5537.79	5564.74	5578.16	5596.78	5578.29	5614.87	5647.39	5692.94	5426.70	5426.41	5363.15	5280.63	5133.16	4915.17	4625.79	4274.84	4351.90	4346.13	4333.63	4309.24	4283.27	4231.29	4212.29	4176.16	4131.62	4052.36	4337.37
Covered Emissions Goal	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	5428.87	5428.87	5428.87	5428.87	5428.87	5428.87	5428.87	5428.87	4460.50	4460.50	4460.50	4460.50	4460.50	4460.50	4460.50	4460.50	4460.50	4460.50	3209.43
Allowance Banking (borrowing)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.00	0.00	65.72	148.24	295.71	513.70	803.07	1154.03	108.60	114.37	126.87	151.26	177.23	229.21	248.21	284.34	328.89	408.14	-1127.94
Cumulative Bank Balance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.00	0.00	65.72	213.96	509.67	1023.37	1826.44	2980.47	3089.07	3203.44	3330.31	3481.57	3658.80	3888.01	4136.21	4420.56	4749.44	5157.59	4029.65
Total Energy-Related Carbon Dioxide Emissions	5923.13	5945.32	5932.31	5967.62	5948.22	5981.32	6009.54	6051.30	6063.73	6077.35	6074.76	6098.04	6117.15	6114.19	6097.91	6082.35	6084.07	6067.96	6042.73	6009.46	5971.09	5903.10	5868.20	5817.47	5756.12	5656.08	5549.70
Total Other Greenhouse Gases	1181.36	1201.97	1216.01	1226.99	1240.56	1253.92	1267.86	1281.94	1206.17	1211.61	1216.05	1219.90	1221.99	1223.04	1223.49	1223.74	1234.87	1259.99	1283.78	1306.88	1328.63	1350.89	1373.48	1394.81	1416.25	1438.38	1465.94
Total GHG Emissions	7104.50	7147.29	7148.32	7194.61	7188.78	7235.24	7277.40	7333.25	7269.91	7288.96	7290.81	7317.94	7339.14	7337.24	7321.40	7306.09	7318.94	7327.96	7326.50	7316.35	7299.71	7253.98	7241.68	7212.28	7172.37	7094.46	7015.65
Other Greenhouse Gases (million metric tons)																											
Baseline Emissions Assumed																											
Methane	606.54	611.87	613.58	615.40	617.32	619.35	621.48	622.77	624.14	625.58	627.09	628.68	632.01	635.40	638.85	642.37	645.94	649.58	653.28	657.05	660.88	664.78	668.76	672.80	676.91	681.10	685.36
Landfills	148.85	155.73	154.48	153.24	152.01	150.79	149.59	149.28	148.97	148.67	148.36	148.06	147.91	147.75	147.60	147.45	147.30	147.14	146.99	146.84	146.69	146.54	146.39	146.23	146.08	145.93	145.78
Coal Mines	67.34	65.52	64.48	63.46	62.46	61.47	60.50	59.36	58.23	57.13	56.06	55.00	54.99	54.99	54.98	54.98	54.97	54.97	54.96	54.96	54.95	54.95	54.94	54.94	54.93	54.93	54.92
Natural Gas	154.75	154.05	157.46	160.94	164.50	168.14	171.87	174.82	177.83	180.88	183.99	187.16	190.48	193.86	197.30	200.80	204.37	207.99	211.68	215.44	219.26	223.16	227.12	231.15	235.25	239.42	243.67
Other	235.61	236.58	237.16	237.75	238.35	238.94	239.53	239.32	239.11	238.89	238.68	238.47	238.64	238.80	238.97	239.14	239.31	239.47	239.64	239.81	239.98	240.14	240.31	240.48	240.65	240.82	240.99
Non-Energy Carbon Dioxide	65.47	63.33	66.32	65.61	66.82	67.12	67.27	67.75	66.72	67.32	67.80	68.64	69.57	69.86	70.04	70.60	71.50	72.09	72.63	73.03	73.45	74.02	74.59	75.14	75.38	75.20	74.94
Nitrous Oxide	359.87	366.56	367.06	367.62	368.23	368.89	369.61	370.38	372.05	373.72	375.41	377.10	379.19	381.30	383.42	385.56	387.71	389.87	392.05	394.24	396.44	398.66	400.89	403.13	405.39	407.67	409.96
Agriculture	272.89	279.87	281.62	283.38	285.15	286.93	288.72	290.52	291.72	292.93	294.15	295.37	296.71	298.06	299.42	300.79	302.16	303.53	304.91	306.30	307.70	309.10	310.51	311.92	313.34	314.77	316.20
Mobile Combustion	52.05	52.59	51.08	49.62	48.19	46.81	45.47	44.16	44.35	44.53	44.72	44.91	45.36	45.83	46.30	46.77	47.25	47.73	48.22	48.71	49.21	49.71	50.22	50.73	51.25	51.77	52.30
Other	34.94	34.09	34.36	34.62	34.89	35.15	35.42	35.70	35.97	36.26	36.54	36.82	37.12	37.41	37.71	38.01	38.31	38.61	38.92	39.23	39.54	39.85	40.17	40.49	40.81	41.13	41.46
High GWP Gases	149.48	160.22	169.04	178.36	188.19	198.56	209.50	221.04	232.54	244.64	257.36	270.75	282.84	295.47	308.66	322.45	336.85	351.89	367.60	384.02	401.17	419.08	437.80	457.35	477.77	499.10	521.39
Total Baseline	1181.36	1201.97	1216.01	1226.99	1240.56	1253.92	1267.86	1281.94	1295.44	1311.26	1327.66	1345.17	1363.61	1382.04	1400.98	1420.97	1441.99	1463.43	1485.56	1508.33	1531.94	1556.54	1582.03	1608.42	1635.45	1663.07	1691.65
Abatement and Offsets																											
Methane	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	54.69	59.04	63.94	69.68	77.13	85.17	93.84	103.23	104.36	99.09	95.70	93.59	93.95	95.03	96.95	101.22	106.14	111.03	112.26
Landfills	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	29.70	32.02	34.61	37.69	42.05	46.77	51.87	57.39	57.37	53.36	50.69	48.93	48.98	49.61	50.67	53.44	56.70	59.98	60.85
Coal Mines	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	17.30	18.51	19.87	21.37	22.48	23.60	24.73	25.87	26.92	27.58	28.20	28.76	29.20	29.58	29.69	29.79	29.85	29.90	29.92
Natural Gas	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	5.62	6.18	6.78	7.53	8.93	10.48	12.22	14.15	14.15	12.60	11.51	10.73	10.66	10.80	11.03	11.97	13.13	14.31	14.58
Other	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	2.07	2.33	2.68	3.09	3.67	4.31	5.02	5.81	5.92	5.54	5.31	5.17	5.10	5.08	5.56	6.02	6.45	6.84	6.91
Non-Energy Carbon Dioxide	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nitrous Oxide	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	16.04	17.60	19.42	21.46	23.78	26.25	28.88	31.70	33.11	32.94	33.02	33.27	33.55	33.85	34.36	34.81	35.23	35.61	35.26
Agriculture	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	6.94	7.65	8.53	9.55	10.92	12.42	14.07	15.89	16.34	15.76	15.46	15.34	15.35	15.44	15.85	16.25	16.63	16.98	16.62
Mobile Combustion	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	9.09	9.95	10.89	11.91	12.86	13.83	14.81	15.81	16.78	17.19	17.57	17.92	18.20	18.41	18.50	18.56	18.60	18.63	18.64
High GWP Gases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	18.54	23.01	28.25	34.12	40.71	47.58	54.76	62.30	69.64	71.40	73.06	74.59	75.81	76.77	77.24	77.58	77.84	78.06	78.18
Total Reductions	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	89.27	99.65	111.61	125.27	141.62	158.99	177.49	197.23	207.12	203.43	201.78	201.44	203.31	205.66	208.55	213.61	219.21	224.69	225.71
Resulting Emissions																											
Methane	606.54	611.87	613.58	615.40	617.32	619.35	621.48	622.77	569.45	566.54	563.15	559.00	554.88	550.24	545.01	539.14	541.58	550.49	557.58	563.46	566.93	569.76	571.80	571.58	570.78	570.07	573.10
Landfills	148.85	155.73	154.48	153.24	152.01	150.79	149.59	149.28	119.28	116.65	113.75	110.37	105.85	100.98	95.73	90.05	89.93	93.78	96.30	97.91	97.70	96.93	95.71	92.80	89.38	85.95	84.93
Coal Mines	67.34	65.52	64.48	63.46	62.46	61.47	60.50	59.36	40.93	38.62	36.18	33.63	32.51	31.39	30.25	29.11	28.05	27.39	26.77	26.20	25.75	25.40	25.25	25.15	25.08	25.03	25.00
Natural Gas	154.75	154.05	157.46	160.94	164.50	168.14	171.87	174.82	172.21	174.71	177.21	179.62	181.55	183.38	185.08	186.65	190.21	195.39	200.17	204.71	208.60	212.36	216.09	219.18	222.12	225.11	229.09
Other	235.61	236.58	237.16	237.75	238.35	238.94	239.53	239.32	237.03	236.56	236.01	235.38	234.97	234.49	233.95	233.32	233.39	233.93	234.33	234.64	234.87	235.07	234.75	234.46	234.20	233.98	234.07
Non-Energy Carbon Dioxide	65.47	63.33	66.32	65.61	66.82	67.12	67.27	67.75	66.72	67.32	67.80	68.64	69.57	69.86	70.04	70.60	71.50	72.09	72.63	73.03	73.45	74.02	74.59	75.14	75.38	75.20	74.94
Nitrous Oxide	359.87	366.56	367.06	367.62	368.23	368.89	369.61	370.38	356.01	356.12	355.99	355.63	355.41	355.06	354.54	353.86	354.59	356.93	359.02	360.97	362.89	364.80	366.53	368.32	370.17	372.06	374.69
Agriculture	272.89	279.87	281.62	283.38	285.15	286.93	288.72	290.52	284.78	285.28	285.62	285.81	285.79	285.64	285.35	284.89	285.82	287.77	289.46	290.96	292.34	293.65	294.65	295.67	296.72	297.79	299.58
Mobile Combustion	52.05	52.59	51.08	49.62	48.19	46.81	45.47	44.16	44.35	44.53	44.72	44.91	45.36	45.83	46.30	46.77	47.25	47.73	48.22	48.71	49.21	49.71	50.22	50.73	51.25	51.77	52.30
Other	34.94	34.09	34.36	34.62	34.89	35.15	35.42	35.70	26.88	26.31	25.65	24.91	24.26	23.58	22.90	22.19	21.53	21.43	21.35	21.31	21.34	21.44	21.66	21.92	22.21	22.50	22.81
High GWP Gases	149.48	160.22	169.04	178.36	188.19	198.56	209.50	221.04	214.00	221.63	229.11	236.63	242.13	247.89	253.90	260.15	267.20	280.48	294.55	309.43	325.36	342.31	360.55	379.76	399.93	421.05	443.21
Total Other Greenhouse Gas Emissions	1181.36	1201.97	1216.01	1226.99	1240.56	1253.92	1267.86	1281.94	1206.17	1211.61	1216.05	1219.90	1221.99	1223.04	1223.49	1223.74	1234.87	1259.99	1283.78	1306.88	1328.63	1350.89	1373.48	1394.81	1416.25	1438.38	1465.94

Note: Totals may not equal sum of components due to independent rounding. Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
N/A = Not applicable.
Sources: 2004 and 2005 emissions and emission factors: Energy Information Administration (EIA), Emissions of Greenhouse Gases in the United States 2005, DOE/EIA-0573(2005) (Washington, DC, November 2006). Projections: EIA, AEO2007 National Energy Modeling System run s280nuc d060207a.

HEARING EXHIBIT

Table 21 Greenhouse Gas Emissions Results
(2005 dollars per million Btu)
(million metric tons carbon dioxide equivalent)

Attachment POD-1 h Table 21 Greenhouse Gas Emission Results S 280 - Low Discount Case

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Allowance Price																											
Emission Price (2005 dollars per ton)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	16.06	16.70	17.37	18.06	18.78	19.54	20.32	21.13	21.98	22.85	23.77	24.72	25.71	26.74	27.81	28.92	30.07	31.28	32.53
Emission Price (nominal dollars per ton)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	16.57	19.70	20.85	22.07	23.38	24.75	26.20	27.76	29.38	31.14	33.04	35.02	37.14	39.41	41.79	44.35	47.07	49.93	52.99
Offset Price (2005 dollars per ton)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	16.06	16.70	17.37	18.06	18.78	19.54	20.32	21.13	20.64	20.47	20.32	20.22	20.13	20.06	20.87	21.69	22.54	23.46	23.22
Greenhouse Gas Emissions Cap Compliance																											
Covered Energy-Related Carbon Dioxide	5220.57	5241.59	5245.70	5258.26	5197.65	5224.55	5246.66	5283.34	5293.64	5293.64	5308.63	5318.43	5330.28	5347.46	5364.62	5381.62	5393.73	5396.40	5379.55	5367.90	5357.41	5358.70	5354.54	5357.61	5335.80	5307.74	5278.57
Covered Other Greenhouse Gas Emissions	317.22	323.16	334.21	342.07	352.38	362.31	372.67	383.80	344.47	349.31	354.73	360.81	366.11	371.30	376.90	383.26	390.41	403.79	418.31	433.57	449.78	467.02	485.98	505.75	526.37	547.79	570.19
Offsets Purchased	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	511.16	580.23	664.29	764.19	876.25	1013.03	1175.95	1366.49	1336.51	1339.22	1338.43	1339.42	1338.34	1338.12	1339.41	1337.45	1339.26	1339.56	964.37
Noncovered Gases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	47.49	52.95	58.82	65.14	71.16	77.46	84.08	91.03	92.88	94.31	95.67	97.59	99.37	101.23	104.58	107.88	111.23	112.38	111.88
Domestic Agriculture/Forestry Sequestration	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	106.81	119.67	133.60	148.66	169.34	192.49	218.23	246.72	256.41	268.00	279.76	291.94	304.18	316.62	346.17	375.41	404.79	434.80	439.72
International Offsets	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	356.85	407.61	471.87	550.39	635.75	743.09	873.64	1028.74	987.22	976.91	962.80	949.89	934.80	920.27	888.66	854.15	823.24	792.38	412.77
Covered Emissions Less Offsets	5537.79	5564.74	5579.90	5600.34	5550.03	5586.85	5619.33	5667.14	5126.95	5062.72	4999.06	4915.05	4820.14	4705.73	4565.57	4398.39	4447.63	4460.98	4459.43	4462.06	4468.85	4487.61	4501.11	4525.92	4522.90	4515.97	4884.39
Covered Emissions Goal	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	5428.87	5428.87	5428.87	5428.87	5428.87	5428.87	5428.87	5428.87	4460.50	4460.50	4460.50	4460.50	4460.50	4460.50	4460.50	4460.50	4460.50	4460.50	3209.43
Allowance Banking (borrowing)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	301.92	366.15	429.80	513.81	608.73	723.14	863.30	1030.48	12.87	-0.48	1.07	-1.56	-8.35	-27.11	-40.61	-65.42	-62.40	-55.47	-1674.95
Cumulative Bank Balance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	301.92	668.07	1097.87	1611.69	2220.41	2943.56	3806.85	4837.33	4850.20	4849.72	4850.79	4849.23	4840.89	4813.78	4773.17	4707.75	4645.35	4589.88	2914.93
Total Energy-Related Carbon Dioxide Emissions	5923.13	5945.32	5934.05	5971.13	5920.19	5953.44	5981.66	6025.20	6043.59	6050.04	6069.92	6084.12	6100.86	6119.50	6140.47	6161.06	6179.15	6184.02	6168.62	6160.29	6153.94	6157.69	6156.93	6162.79	6144.75	6119.75	6095.26
Total Other Greenhouse Gases	1181.36	1201.97	1216.01	1227.01	1240.58	1253.92	1267.84	1281.90	1198.95	1202.27	1205.81	1209.63	1214.06	1218.15	1222.41	1227.18	1237.90	1255.35	1273.89	1293.09	1313.24	1334.44	1355.94	1378.38	1401.71	1428.12	1457.25
Total GHG Emissions	7104.50	7147.29	7150.06	7198.14	7160.77	7207.36	7249.50	7307.10	7242.54	7252.32	7275.73	7293.75	7314.71	7337.65	7362.88	7388.24	7417.05	7439.38	7442.51	7453.38	7467.19	7492.12	7512.87	7541.16	7546.46	7547.88	7552.51
Other Greenhouse Gases																											
(million metric tons)																											
Baseline Emissions Assumed																											
Methane	606.54	611.87	613.58	615.40	617.32	619.35	621.48	622.77	624.14	625.58	627.09	628.68	632.01	635.40	638.85	642.37	645.94	649.58	653.28	657.05	660.88	664.78	668.76	672.80	676.91	681.10	685.36
Landfills	148.85	155.73	154.48	153.24	152.01	150.79	149.59	149.28	148.97	148.67	148.36	148.06	147.91	147.75	147.60	147.45	147.30	147.14	146.99	146.84	146.69	146.54	146.39	146.23	146.08	145.93	145.78
Coal Mines	67.34	65.52	64.48	63.46	62.46	61.47	60.50	59.36	58.23	57.13	56.06	55.00	54.99	54.98	54.98	54.98	54.97	54.97	54.96	54.96	54.95	54.95	54.94	54.94	54.93	54.93	54.92
Natural Gas	154.75	154.05	157.46	160.94	164.50	168.14	171.87	174.82	177.83	180.88	183.99	187.16	190.48	193.86	197.30	200.80	204.37	207.99	211.68	215.44	219.26	223.16	227.12	231.15	235.25	239.42	243.67
Other	235.61	236.58	237.16	237.75	238.35	238.94	239.53	239.32	239.11	238.89	238.68	238.47	238.64	238.80	238.97	239.14	239.31	239.47	239.64	239.81	239.98	240.14	240.31	240.48	240.65	240.82	240.99
Non-Energy Carbon Dioxide	65.47	63.33	66.32	65.63	66.85	67.13	67.25	67.70	66.20	66.69	67.35	68.23	69.23	69.71	70.18	70.98	72.10	72.90	73.58	74.19	74.89	75.74	76.49	77.16	77.71	77.99	78.18
Nitrous Oxide	359.87	366.56	367.06	367.62	368.23	368.89	369.61	370.38	371.25	372.05	373.72	375.41	377.10	379.19	381.30	383.42	385.56	387.71	389.87	392.05	394.24	396.44	398.66	400.89	403.13	405.39	407.67	409.96
Agriculture	272.89	279.87	281.62	283.38	285.15	286.93	288.72	290.52	291.72	292.93	294.15	295.37	296.71	298.06	299.42	300.79	302.16	303.53	304.91	306.30	307.70	309.10	310.51	311.92	313.34	314.77	316.20
Mobile Combustion	52.05	52.59	51.08	49.62	48.19	46.81	45.47	44.16	44.35	44.53	44.72	44.91	45.36	45.83	46.30	46.77	47.25	47.73	48.22	48.71	49.21	49.71	50.22	50.73	51.25	51.77	52.30
Other	34.94	34.09	34.36	34.62	34.89	35.15	35.42	35.70	35.97	36.26	36.54	36.82	37.12	37.41	37.71	38.01	38.31	38.61	38.92	39.23	39.54	39.85	40.17	40.49	40.81	41.13	41.46
High GWP Gases	149.48	160.22	169.04	178.36	188.19	198.56	209.50	221.04	232.54	244.64	257.36	270.75	282.84	295.47	308.66	322.45	336.85	351.89	367.60	384.02	401.17	419.08	437.80	457.35	477.77	499.10	521.39
Total Baseline	1181.36	1201.97	1216.01	1227.01	1240.58	1253.92	1267.84	1281.90	1294.93	1310.63	1327.21	1344.76	1363.27	1381.88	1401.12	1421.35	1442.60	1464.23	1486.51	1509.49	1533.38	1558.26	1583.93	1610.44	1637.79	1665.86	1694.90
Abatement and Offsets																											
Methane	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	57.58	63.53	69.89	76.69	82.45	88.44	94.68	101.17	103.29	104.69	106.13	107.67	109.24	110.85	114.33	117.76	121.22	122.46	122.73
Landfills	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	31.14	34.55	38.20	42.13	45.41	48.83	52.40	56.11	56.85	57.36	57.95	58.64	59.36	60.13	62.37	64.61	66.88	67.33	67.64
Coal Mines	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	17.94	19.26	20.62	22.04	22.96	23.88	24.79	25.71	26.62	27.22	27.73	28.21	28.67	29.10	29.28	29.45	29.61	29.72	29.81
Natural Gas	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	5.95	6.86	7.86	8.95	10.03	11.18	12.40	13.70	13.97	14.04	14.15	14.28	14.43	14.59	15.37	16.16	16.97	17.43	17.42
Other	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	2.55	2.86	3.21	3.58	4.05	4.55	5.09	5.65	5.85	6.07	6.30	6.54	6.78	7.02	7.29	7.54	7.77	7.98	7.87
Non-Energy Carbon Dioxide	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nitrous Oxide	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	17.29	19.03	20.86	22.77	24.80	26.89	29.05	31.28	32.79	33.79	34.75	35.71	36.67	37.61	37.78	37.93	38.06	38.16	37.52
Agriculture	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	7.86	8.68	9.55	10.49	11.66	12.90	14.20	15.57	16.21	16.83	17.47	18.13	18.80	19.48	19.54	19.58	19.61	19.64	18.95
Mobile Combustion	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	9.44	10.35	11.30	12.28	13.13	13.99	14.85	15.72	16.59	16.96	17.28	17.58	17.86	18.13	18.25	18.35	18.45	18.52	18.57
High GWP Gases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	21.10	25.80	30.65	35.66	41.97	48.40	54.99	61.72	68.61	70.39	71.74	73.03	74.24	75.37	75.89	76.37	76.80	77.12	77.39
Total Reductions	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	95.98	108.36	121.40	135.13	149.22	163.74	178.71	194.17	204.69	208.88	212.62	216.41	220.14	223.83	228.00	232.06	236.08	237.74	237.65
Resulting Emissions																											
Methane	606.54	611.87	613.58	615.40	617.32	619.35	621.48	622.77	566.56	562.05	557.20	551.99	549.56	546.96	544.18	541.20	542.65	544.88	547.15	549.38	551.64	553.94	554.43	555.04	555.69	558.64	562.63
Landfills	148.85	155.73	154.48	153.24	152.01	150.79	149.59	149.28	117.83	114.12	110.16	105.93	102.49	98.92	95.20	91.34	90.44	89.78	89.04	88.20	87.32	86.40	84.01	81.63	79.21	78.60	78.14
Coal Mines	67.34	65.52	64.48	63.46	62.46	61.47	60.50	59.36	40.29	37.88	35.43	32.96	32.03	31.11	30.19	29.27	28.35	27.75	27.23	26.74	26.28	25.85	25.66	25.48	25.33	25.21	25.12
Natural Gas	154.75	154.05	157.46	160.94	164.50	168.14	171.87	174.82	171.88	174.02	176.14	178.21	180.45	182.68	184.90	187.10	190.40	193.95	197.54	201.16	204.84	208.56	211.74	214.98	218.28	221.99	226.25
Other	235.61	236.58	237.16	237.75	238.35	238.94	239.53	239.32	236.56	236.03	235.48	234.89	234.59	234.25	233.88	233.49	233.46	233.40	233.34	233.27	233.20	233.12	233.02	232.94	232.88	232.84	233.12
Non-Energy Carbon Dioxide	65.47	63.33	66.32	65.63	66.85	67.13	67.25	67.70	66.20	66.69	67.35	68.23	69.23	69.71	70.18	70.98	72.10	72.90	73.58	74.19	74.89	75.74	76.49	77.16	77.71	77.99	78.18
Nitrous Oxide	359.87	366.56	367.06	367.62	368.23	368.89	369.61	370.38	354.75	354.69	354.55	354.33	354.40	354.41	354.37	354.27	354.92	356.08	357.30	358.52	359.77	361.05	363.11	365.21	367.33	369.51	372.44
Agriculture	272.89	279.87	281.62	283.38	285.15	286.93	288.72	290.52	283.87	284.25	284.59	284.88	285.05	285.17	285.22	285.22	285.95	286.70	287.44	288.17	288.90	289.62	290.97	292.34	293.73	295.13	297.25
Mobile Combustion	52.05	52.59	51.08	49.62	48.19	46.81	45.47	44.16	44.35	44.53	44.72	44.91	45.36	45.83	46.30	46.77	47.25	47.73	48.22	48.71	49.21	49.71	50.22	50.73	51.25	51.77	52.30
Other	34.94	34.09	34.36	34.62	34.89	35.15	35.42	35.70	26.54	25.90	25.24	24.54	23.98	23.42	22.86	22.29	21.72	21.65	21.64	21.65	21.67	21.72	21.92	22.13	22.36	22.61	22.88
High GWP Gases	149.48	160.22	169.04	178.36	188.19	198.56	209.50	221.04	211.43	218.84	226.71	235.09	240.87	247.06	253.68	260.73	268.24	281.49	295.86	310.99	326.93	343.71	361.91	380.98	400.97	421.98	444.00
Total Other Greenhouse Gas Emissions	1181.36	1201.97	1216.01	1227.01	1240.58	1253.92	1267.84	1281.90	1198.95	1202.27	1205.81	1209.63	1214.06	1218.15	1222.41	1227.18	1237.90	1255.35	1273.89	1293.09	1313.24	1334.44	1355.94	1378.38	1401.71	1428.12	1457.25

Note: Totals may not equal sum of components due to independent rounding. Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
N/A = Not applicable.
Sources: 2004 and 2005 emissions and emission factors: Energy Information Administration (EIA), Emissions of Greenhouse Gases in the United States 2005, DOE/EIA-0573(2005) (Washington, DC, November 2006). Projections: EIA, AEO2007 National Energy Modeling System run s280r4.d061507a.

HEARING EXHIBIT - 00000205

Table 21. Greenhouse Gas Emissions Results
(2005 dollars per million Btu)
(million metric tons carbon dioxide equivalent)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Allowance Price																											
Emission Price (2005 dollars per	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	13.25	13.91	14.60	15.06	15.34	15.69	16.38	17.69	19.11	19.24	17.84	16.79	15.96	17.23	18.61	20.10	21.71	23.45	25.32
Emission Price (nominal dollars p	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	15.32	16.40	17.51	18.18	19.08	19.86	21.12	23.25	25.57	26.25	24.83	23.77	23.03	25.37	27.92	30.75	33.86	37.27	41.05
Offset Price (2005 dollars per to	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	13.25	13.91	14.60	15.06	15.34	15.69	16.38	17.69	19.11	19.24	17.84	16.79	15.96	17.23	18.61	20.10	21.71	23.45	25.32
Greenhouse Gas Emissions Cap Compliance																											
Covered Energy-Related Carbon Dioxid	5220.57	5241.59	5245.73	5257.89	5239.93	5262.32	5285.08	5317.23	5323.83	5334.96	5361.28	5366.91	5390.25	5426.16	5447.14	5459.65	5467.43	5495.72	5529.31	5575.09	5617.17	5628.85	5635.75	5630.00	5606.75	5605.52	5590.66
Covered Other Greenhouse Gas Emissio	317.22	323.16	334.21	342.09	352.41	362.36	372.71	383.85	348.33	353.59	359.11	365.74	371.67	377.30	383.14	388.90	395.12	409.03	426.21	443.39	460.75	475.97	493.11	511.22	530.24	550.46	572.26
Offsets Purchased	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	246.37	260.11	290.96	306.25	333.84	377.42	484.18	717.33	1007.36	1446.48	1500.80	1560.68	1621.79	2380.54	2433.57	2512.78	2619.73	2740.60	2878.01
Noncovered Gases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	44.44	48.32	52.41	56.37	59.85	63.45	69.01	77.41	86.58	89.28	85.61	83.34	81.96	69.38	95.24	101.40	107.88	112.36	114.67
Domestic Agriculture/Forestry Sequ	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	88.80	99.65	111.50	122.24	133.73	146.68	165.49	195.62	231.29	246.38	232.54	222.04	213.59	251.46	294.93	339.91	386.47	434.54	483.98
International Offsets	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	113.14	112.14	127.06	127.64	140.26	167.49	249.69	444.29	689.48	1110.82	1182.65	1255.31	1326.24	2039.70	2043.40	2071.48	2125.39	2193.70	2279.37
Covered Emissions Less Offsets	5537.79	5564.74	5579.93	5599.97	5592.34	5624.68	5657.79	5701.09	5425.78	5428.24	5429.42	5426.40	5428.08	5426.04	5346.11	5331.23	4855.19	4458.28	4454.72	4457.80	4456.12	3724.28	3695.29	3628.44	3517.25	3415.38	3284.92
Covered Emissions Goal	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	5428.87	5428.87	5428.87	5428.87	5428.87	5428.87	5428.87	5428.87	4660.50	4460.50	4460.50	4460.50	4460.50	4460.50	4460.50	4460.50	4460.50	4460.50	3209.43
Allowance Banking (borrowing)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	3.09	0.63	-0.55	2.47	0.79	2.83	82.76	297.64	-394.69	-2.22	5.78	2.70	4.38	736.22	765.21	832.06	943.25	1045.12	-75.48
Cumulative Bank Balance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	3.09	3.71	3.16	5.63	6.42	9.25	92.00	389.64	-5.05	-2.82	2.95	5.65	10.03	746.25	1511.46	2343.52	3286.77	4331.89	4256.41
Total Energy-Related Carbon Dioxide Em	5923.13	5945.32	5934.08	5970.86	5962.60	5991.56	6020.38	6059.53	6073.86	6091.52	6122.50	6132.42	6160.18	6197.41	6221.57	6237.39	6249.96	6280.08	6315.90	6364.70	6410.55	6424.39	6434.29	6431.80	6412.88	6414.65	6404.35
Total Other Greenhouse Gases	1181.36	1201.97	1216.01	1227.02	1240.61	1253.97	1267.88	1281.95	1205.87	1211.18	1216.60	1223.33	1230.93	1238.16	1243.72	1246.43	1248.90	1265.62	1292.05	1317.15	1341.62	1355.23	1372.40	1390.33	1408.93	1430.81	1456.54
Total GHG Emissions	7104.50	7147.29	7150.10	7197.88	7203.21	7245.53	7288.26	7341.49	7279.73	7302.70	7339.11	7355.75	7391.11	7435.57	7465.29	7483.82	7498.86	7545.70	7607.94	7681.85	7752.17	7779.62	7806.69	7822.12	7821.81	7845.46	7860.89
Other Greenhouse Gases																											
(million metric tons)																											
Baseline Emissions Assumed																											
Methane	606.54	611.87	613.58	615.40	617.32	619.35	621.48	622.77	624.14	625.58	627.09	628.68	632.01	635.40	638.85	642.37	645.94	649.58	653.28	657.05	660.88	664.78	668.76	672.80	676.91	681.10	685.36
Landfills	148.85	155.73	154.48	153.24	152.01	150.79	149.59	149.28	148.97	148.67	148.36	148.06	147.91	147.75	147.60	147.45	147.30	147.14	146.99	146.84	146.69	146.54	146.39	146.23	146.08	145.93	145.78
Coal Mines	67.34	65.52	64.48	63.46	62.46	61.47	60.50	59.36	58.23	57.13	56.06	55.00	54.99	54.99	54.98	54.98	54.97	54.97	54.96	54.96	54.95	54.95	54.94	54.94	54.93	54.93	54.92
Natural Gas	154.75	154.05	157.46	160.94	164.50	168.14	171.87	174.82	177.83	180.88	183.99	187.16	190.48	193.86	197.30	200.80	204.37	207.99	211.68	215.44	219.26	223.16	227.12	231.15	235.25	239.42	243.67
Other	235.61	236.58	237.16	237.75	238.35	238.94	239.53	239.32	239.11	238.89	238.68	238.47	238.64	238.80	238.97	239.14	239.31	239.47	239.64	239.81	239.98	240.14	240.31	240.48	240.65	240.82	240.99
Non-Energy Carbon Dioxide	65.47	63.33	66.32	65.65	66.87	67.18	67.29	67.76	66.66	67.25	67.87	68.82	69.87	70.37	70.82	71.49	72.33	73.04	74.16	75.24	76.21	76.88	77.51	78.20	78.86	79.08	79.20
Nitrous Oxide	359.87	366.56	367.06	367.62	368.23	368.89	369.61	370.38	371.20	372.05	373.72	375.41	377.10	379.19	381.30	383.42	385.56	387.71	389.87	392.05	394.24	396.44	398.66	400.89	403.13	405.39	407.67
Agriculture	272.89	279.87	281.62	283.38	285.15	286.93	288.72	290.52	291.72	292.93	294.15	295.37	296.71	298.06	299.42	300.79	302.16	303.53	304.91	306.30	307.70	309.10	310.51	311.92	313.34	314.77	316.20
Mobile Combustion	52.05	52.59	51.08	49.62	48.19	46.81	45.47	44.16	44.35	44.53	44.72	44.91	45.36	45.83	46.30	46.77	47.25	47.73	48.22	48.71	49.21	49.71	50.22	50.73	51.25	51.77	52.30
Other	34.94	34.09	34.36	34.62	34.89	35.15	35.42	35.70	35.97	36.26	36.54	36.82	37.12	37.41	37.71	38.01	38.31	38.61	38.92	39.23	39.54	39.85	40.17	40.49	40.81	41.13	41.46
High GWP Gases	149.48	160.22	169.04	178.36	188.19	198.56	209.50	221.04	233.89	247.09	260.68	274.70	289.19	304.19	319.73	335.85	352.58	369.96	388.03	406.82	426.37	446.72	467.91	489.99	513.00	536.99	562.00
Total Baseline	1181.36	1201.97	1216.01	1227.02	1240.61	1253.97	1267.88	1281.95	1295.39	1311.18	1327.73	1345.35	1363.91	1382.55	1401.76	1421.86	1442.83	1464.38	1487.08	1510.54	1534.70	1559.40	1584.95	1611.48	1638.94	1666.95	1695.91
Abatement and Offsets																											
Methane	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	54.79	59.17	63.77	68.26	71.69	75.22	80.58	88.54	97.13	99.53	96.19	94.20	93.07	99.70	105.53	111.60	117.92	122.13	124.05
Landfills	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	29.74	32.08	34.53	36.93	38.71	40.54	43.55	48.21	53.25	54.51	52.18	50.69	49.74	53.64	57.23	61.02	65.02	67.33	67.80
Coal Mines	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	17.33	18.55	19.83	21.08	21.89	22.92	23.64	24.73	25.82	26.32	26.45	26.71	27.06	27.81	28.28	28.71	29.10	29.40	29.61
Natural Gas	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	5.63	6.19	6.77	7.34	7.87	8.40	9.37	10.93	12.68	13.01	12.05	11.38	10.89	12.19	13.46	14.82	16.27	17.43	18.26
Other	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	2.09	2.36	2.65	2.91	3.22	3.57	4.02	4.67	5.39	5.69	5.51	5.42	5.39	6.06	6.56	7.05	7.53	7.97	8.39
Non-Energy Carbon Dioxide	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nitrous Oxide	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	16.09	17.67	19.33	20.94	22.57	24.26	26.23	28.71	31.36	32.47	32.35	32.50	32.81	34.82	35.60	36.40	37.20	37.95	38.67
Agriculture	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	6.98	7.70	8.47	9.19	10.04	10.95	12.07	13.60	15.27	16.07	15.87	15.85	15.95	17.49	17.98	18.51	19.06	19.63	20.22
Mobile Combustion	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	9.11	9.97	10.86	11.75	12.52	13.32	14.16	15.12	16.09	16.40	16.48	16.64	16.86	17.33	17.62	17.89	18.13	18.32	18.45
High GWP Gases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	18.65	23.16	28.03	32.83	38.73	44.90	51.23	58.17	65.44	66.76	66.49	66.70	67.20	69.65	71.41	73.16	74.89	76.06	76.65
Total Reductions	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	89.52	100.00	111.13	122.02	132.99	144.39	158.04	175.43	193.93	198.75	195.04	193.39	193.08	204.17	212.55	221.16	230.01	236.14	239.37
Resulting Emissions																											
Methane	606.54	611.87	613.58	615.40	617.32	619.35	621.48	622.77	569.35	566.41	563.33	560.42	560.32	560.18	558.27	553.82	548.81	550.04	557.09	562.85	567.81	565.08	563.23	561.20	559.00	558.97	561.31
Landfills	148.85	155.73	154.48	153.24	152.01	150.79	149.59	149.28	119.23	116.58	113.83	111.13	109.19	107.22	104.05	99.24	94.05	92.64	94.81	96.15	96.95	92.89	89.15	85.21	81.07	78.60	77.98
Coal Mines	67.34	65.52	64.48	63.46	62.46	61.47	60.50	59.36	40.91	38.59	36.23	33.92	33.10	32.27	31.34	30.25	29.15	28.65	28.51	28.25	27.89	27.13	26.67	26.23	25.83	25.53	25.31
Natural Gas	154.75	154.05	157.46	160.94	164.50	168.14	171.87	174.82	172.20	174.70	177.23	179.82	182.61	185.46	187.93	189.87	191.69	194.98	199.63	204.06	208.38	210.97	213.66	216.33	218.98	222.00	225.42
Other	235.61	236.58	237.16	237.75	238.35	238.94	239.53	239.32	237.01	236.54	236.04	235.56	235.41	235.24	234.95	234.47	233.92	233.78	234.13	234.39	234.59	234.09	233.75	233.43	233.12	232.84	232.60
Non-Energy Carbon Dioxide	65.47	63.33	66.32	65.65	66.87	67.18	67.29	67.76	66.66	67.25	67.87	68.82	69.87	70.37	70.82	71.49	72.33	73.04	74.16	75.24	76.21	76.88	77.51	78.20	78.86	79.08	79.20
Nitrous Oxide	359.87	366.56	367.06	367.62	368.23	368.89	369.61	370.38	355.96	356.06	356.07	356.16	356.63	357.04	357.19	356.84	356.35	357.40	359.70	361.74	363.63	363.83	365.29	366.74	368.19	369.71	371.29
Agriculture	272.89	279.87	281.62	283.38	285.15	286.93	288.72	290.52	284.74	285.24	285.68	286.18	286.67	287.12	287.35	287.19	286.88	287.47	289.04	290.45	291.75	291.61	292.52	293.41	294.28	295.13	295.98
Mobile Combustion	52.05	52.59	51.08	49.62	48.19	46.81	45.47	44.16	44.35	44.53	44.72	44.91	45.36	45.83	46.30	46.77	47.25	47.73	48.22	48.71	49.21	49.71	50.22	50.73	51.25	51.77	52.30
Other	34.94	34.09	34.36	34.62	34.89	35.15	35.42	35.70	26.80	26.29	25.67	25.08	24.59	24.09	23.54	22.89	22.22	22.21	22.44	22.58	22.68	22.52	22.55	22.60	22.67	22.81	23.01
High GWP Gases	149.48	160.22	169.04	178.36	188.19	198.56	209.50	221.04	213.89	221.47	229.33	237.92	244.11	250.57	257.44	264.27	271.41	285.13	301.11	317.32	333.97	349.44	366.38	384.18	402.88	423.05	444.74
Total Other Greenhouse Gas Emissio	1181.36	1201.97	1216.01	1227.02	1240.61	1253.97	1267.88	1281.95	1205.87	1211.18	1216.60	1223.33	1230.93	1238.15	1243.72	1246.43	1248.90	1265.62	1292.05	1317.15	1341.62	1355.23	1372.40	1390.33	1408.93	1430.81	1456.54

Note: Totals may not equal sum of components due to independent rounding. Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
N/A = Not applicable.
Sources: 2004 and 2005 emissions and emission factors: Energy Information Administration (EIA), Emissions of Greenhouse Gases in the United States 2005, DOE/EIA-0573(2005) (Washington, DC, November 2006). Projections: EIA, AEO2007 National Energy Modeling System run s280vhioff25 d061607a.

Table 21. Greenhouse Gas Emissions Results
(2005 dollars per million Btu)
(million metric tons carbon dioxide equivalent)

Attachment POD-1h_Table 21 Greenhouse Gas Emission Results_S280_High Auction Case

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Allowance Price																											
Emission Price (2005 dollars per ton)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.14	13.79	14.44	15.23	16.45	17.77	19.19	20.72	22.38	24.17	26.11	28.19	30.45	32.89	35.52	38.36	41.43	44.74	48.32
Emission Price (nominal dollars per ton)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	15.19	16.26	17.33	18.61	20.48	22.52	24.78	27.28	30.01	33.05	36.44	40.14	44.24	48.76	53.72	59.21	65.28	71.93	79.33
Offset Price (2005 dollars per ton)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.14	13.79	14.44	15.23	16.45	17.77	19.19	20.72	20.87	18.75	17.21	16.02	15.09	14.35	15.52	16.74	17.99	19.28	19.49
Greenhouse Gas Emissions Cap Compliance																											
Covered Energy-Related Carbon Dioxide	5220.57	5241.59	5243.75	5256.06	5225.96	5245.23	5274.62	5308.50	5311.96	5322.72	5337.36	5352.41	5358.76	5373.83	5355.88	5353.73	5337.39	5306.08	5291.30	5265.90	5247.63	5201.16	5111.32	5000.01	4873.03	4748.76	4559.22
Covered Other Greenhouse Gas Emissions	317.22	323.16	334.21	342.05	352.39	362.34	372.70	383.85	348.46	353.77	359.47	365.35	369.65	374.09	378.70	383.83	389.46	402.37	416.25	430.91	446.58	463.83	482.73	502.60	523.37	544.68	566.85
Offsets Purchased	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	235.47	247.35	272.00	328.25	481.88	679.62	931.52	1243.54	1339.16	1338.31	1339.44	1338.11	1338.10	1338.83	1337.85	1336.92	1338.19	1337.92	964.30
Noncovered Gases	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	44.33	48.19	52.22	56.60	62.83	70.92	79.76	89.42	93.82	87.27	83.00	80.15	80.10	80.93	83.12	87.65	92.90	98.12	98.98
Domestic Agriculture/Forestry Sequestration	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	88.06	98.79	110.25	123.67	144.91	171.38	203.11	240.69	260.15	237.76	220.55	206.41	195.43	186.14	224.90	264.61	304.63	344.40	360.30
International Offsets	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	103.08	100.37	109.53	147.98	274.14	437.31	648.65	913.42	985.19	1013.28	1035.88	1051.56	1062.57	1071.76	1029.83	984.67	940.66	895.40	505.01
Covered Emissions Less Offsets	5537.79	5564.74	5577.96	5598.11	5578.35	5607.57	5647.33	5692.35	5424.95	5429.13	5424.83	5389.52	5246.53	5068.31	4803.06	4494.02	4387.70	4370.14	4368.12	4358.71	4356.11	4326.16	4256.20	4165.68	4058.21	3955.52	4161.78
Covered Emissions Goal	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	5428.87	5428.87	5428.87	5428.87	5428.87	5428.87	5428.87	5428.87	4460.50	4460.50	4460.50	4460.50	4460.50	4460.50	4460.50	4460.50	4460.50	4460.50	3209.43
Allowance Banking (borrowing)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.00	0.00	0.00	39.35	182.34	360.56	625.80	934.84	72.80	90.36	92.38	101.80	104.39	134.34	204.30	294.82	402.29	504.98	-952.34
Cumulative Bank Balance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.00	0.00	0.00	39.35	221.69	582.25	1208.05	2142.90	2215.70	2306.06	2398.44	2500.24	2604.63	2738.97	2943.27	3238.09	3640.38	4145.35	3193.01
Total Energy-Related Carbon Dioxide Emissions	5923.13	5945.32	5932.11	5968.67	5948.05	5974.13	6009.67	6050.65	6062.08	6079.22	6098.61	6118.30	6129.60	6146.36	6132.06	6133.16	6121.76	6092.71	6080.19	6057.65	6043.29	5999.33	5913.23	5805.82	5683.57	5562.77	5377.78
Total Other Greenhouse Gases	1181.36	1201.97	1216.01	1226.98	1240.59	1253.95	1267.87	1281.95	1206.11	1211.49	1217.16	1222.71	1225.92	1227.48	1228.53	1229.35	1236.02	1260.97	1284.69	1307.86	1329.32	1351.54	1374.14	1395.46	1417.04	1439.27	1466.81
Total GHG Emissions	7104.50	7147.29	7148.12	7195.65	7188.64	7228.09	7277.54	7332.59	7268.19	7290.71	7315.77	7341.02	7355.52	7373.83	7360.59	7362.51	7357.78	7353.68	7364.89	7365.52	7372.61	7350.87	7287.37	7201.29	7100.61	7002.04	6844.59
Other Greenhouse Gases																											
(million metric tons)																											
Baseline Emissions Assumed																											
Methane	606.54	611.87	613.58	615.40	617.32	619.35	621.48	622.77	624.14	625.58	627.09	628.68	632.01	635.40	638.85	642.37	645.94	649.58	653.28	657.05	660.88	664.78	668.76	672.80	676.91	681.10	685.36
Landfills	148.85	155.73	154.48	153.24	152.01	150.79	149.59	149.28	148.97	148.67	148.36	148.06	147.91	147.75	147.60	147.45	147.30	147.14	146.99	146.84	146.69	146.54	146.39	146.23	146.08	145.93	145.78
Coal Mines	67.34	65.52	64.48	63.46	62.46	61.47	60.50	59.36	58.23	57.13	56.06	55.00	54.99	54.98	54.98	54.98	54.97	54.97	54.96	54.96	54.95	54.95	54.94	54.94	54.93	54.93	54.92
Natural Gas	154.75	154.05	157.46	160.94	164.50	168.14	171.87	174.82	177.83	180.88	183.99	187.16	190.48	193.86	197.30	200.80	204.37	207.99	211.68	215.44	219.26	223.16	227.12	231.15	235.25	239.42	243.67
Other	235.61	236.58	237.16	237.75	238.35	238.94	239.53	239.32	239.11	238.89	238.68	238.47	238.64	238.80	238.97	239.14	239.31	239.47	239.64	239.81	239.98	240.14	240.31	240.48	240.65	240.82	240.99
Non-Energy Carbon Dioxide	65.47	63.33	66.32	65.61	66.86	67.16	67.28	67.75	66.65	67.23	67.93	68.81	69.77	70.11	70.38	70.94	71.78	72.34	72.88	73.31	73.79	74.38	74.98	75.62	76.02	76.00	75.77
Nitrous Oxide	359.87	366.56	367.06	367.62	368.23	368.89	369.61	370.38	372.05	373.72	375.41	377.10	379.19	381.30	383.42	385.56	387.71	389.87	392.05	394.24	396.44	398.66	400.89	403.13	405.39	407.67	409.96
Agriculture	272.89	279.87	281.62	283.38	285.15	286.93	288.72	290.52	291.72	292.93	294.15	295.37	296.71	298.06	299.42	300.79	302.16	303.53	304.91	306.30	307.70	309.10	310.51	311.92	313.34	314.77	316.20
Mobile Combustion	52.05	52.59	51.08	49.62	48.19	46.81	45.47	44.16	44.35	44.53	44.72	44.91	45.36	45.83	46.30	46.77	47.25	47.73	48.22	48.71	49.21	49.71	50.22	50.73	51.25	51.77	52.30
Other	34.94	34.09	34.36	34.62	34.89	35.15	35.42	35.70	35.97	36.26	36.54	36.82	37.12	37.41	37.71	38.01	38.31	38.61	38.92	39.23	39.54	39.85	40.17	40.49	40.81	41.13	41.46
High GWP Gases	149.48	160.22	169.04	178.36	188.19	198.56	209.50	221.04	232.54	244.64	257.36	270.75	282.84	295.47	308.66	322.45	336.85	351.89	367.60	384.02	401.17	419.08	437.80	457.35	477.77	499.10	521.39
Total Baseline	1181.36	1201.97	1216.01	1226.98	1240.59	1253.95	1267.87	1281.95	1295.37	1311.17	1327.79	1345.34	1363.81	1382.28	1401.32	1421.31	1442.28	1463.67	1485.81	1508.61	1532.27	1556.91	1582.42	1608.90	1636.10	1663.87	1692.48
Abatement and Offsets																											
Methane	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	54.69	59.05	63.59	68.48	74.52	82.27	90.64	99.68	104.20	98.93	95.58	93.42	93.88	94.97	96.90	101.17	106.11	111.03	112.27
Landfills	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	29.70	32.03	34.44	37.03	40.41	44.95	49.86	55.17	57.39	53.37	50.71	48.91	48.98	49.61	50.67	53.42	56.70	59.99	60.86
Coal Mines	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	17.30	18.52	19.78	21.14	22.24	23.35	24.46	25.59	26.73	27.41	28.04	28.61	29.13	29.49	29.64	29.77	29.83	29.89	29.92
Natural Gas	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	5.62	6.18	6.75	7.36	8.39	9.87	11.53	13.37	14.16	12.60	11.52	10.73	10.66	10.80	11.03	11.97	13.13	14.31	14.58
Other	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	2.07	2.33	2.61	2.94	3.48	4.10	4.78	5.54	5.92	5.54	5.31	5.17	5.10	5.08	5.56	6.02	6.45	6.84	6.91
Non-Energy Carbon Dioxide	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nitrous Oxide	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	16.04	17.61	19.24	21.04	23.28	25.68	28.24	30.98	33.00	32.84	32.93	33.17	33.50	33.82	34.32	34.79	35.21	35.60	35.26
Agriculture	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	6.94	7.65	8.41	9.26	10.56	12.00	13.59	15.34	16.34	15.76	15.46	15.34	15.35	15.45	15.85	16.24	16.62	16.98	16.62
Mobile Combustion	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	9.09	9.95	10.84	11.78	12.72	13.68	14.65	15.65	16.66	17.08	17.47	17.83	18.15	18.37	18.47	18.55	18.59	18.62	18.64
High GWP Gases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	18.54	23.02	27.80	33.11	40.09	46.85	53.91	61.30	69.06	70.94	72.61	74.16	75.58	76.57	77.05	77.47	77.74	77.97	78.13
Total Reductions	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	89.27	99.68	110.63	122.63	137.89	154.80	172.79	191.96	206.26	202.71	201.12	200.75	202.96	205.37	208.27	213.44	219.06	224.60	225.67
Resulting Emissions																											
Methane	606.54	611.87	613.58	615.40	617.32	619.35	621.48	622.77	569.45	566.53	563.51	560.21	557.49	553.13	548.22	542.69	541.74	550.65	557.70	563.63	567.00	569.81	571.85	571.63	570.81	570.07	573.09
Landfills	148.85	155.73	154.48	153.24	152.01	150.79	149.59	149.28	119.28	116.64	113.92	111.03	107.50	102.80	97.74	92.27	89.90	93.78	96.28	97.93	97.71	96.93	95.71	92.81	89.39	85.94	84.92
Coal Mines	67.34	65.52	64.48	63.46	62.46	61.47	60.50	59.36	40.93	38.62	36.28	33.86	32.75	31.64	30.52	29.38	28.24	27.55	26.93	26.35	25.82	25.46	25.30	25.17	25.10	25.04	25.01
Natural Gas	154.75	154.05	157.46	160.94	164.50	168.14	171.87	174.82	172.21	174.71	177.24	179.80	182.09	183.99	185.77	187.43	190.21	195.39	200.16	204.71	208.60	212.36	216.09	219.18	222.12	225.11	229.09
Other	235.61	236.58	237.16	237.75	238.35	238.94	239.53	239.32	237.03	236.56	236.07	235.53	235.15	234.71	234.19	233.60	233.39	233.93	234.33	234.64	234.87	235.07	234.75	234.46	234.20	233.98	234.07
Non-Energy Carbon Dioxide	65.47	63.33	66.32	65.61	66.86	67.16	67.28	67.75	66.65	67.23	67.93	68.81	69.77	70.11	70.38	70.94	71.78	72.34	72.88	73.31	73.79	74.38	74.98	75.62	76.02	76.00	75.77
Nitrous Oxide	359.87	366.56	367.06	367.62	368.23	368.89	369.61	370.38	356.01	356.12	356.16	356.06	355.91	355.62	355.18	354.58	354.71	357.03	359.11	361.07	362.94	364.84	366.57	368.34	370.18	372.07	374.69
Agriculture	272.89	279.87	281.62	283.38	285.15	286.93	288.72	290.52	284.78	285.28	285.74	286.11	286.16	286.06	285.83	285.45	285.81	287.77	289.45	290.96	292.35	293.65	294.65	295.68	296.72	297.79	299.58
Mobile Combustion	52.05	52.59	51.08	49.62	48.19	46.81	45.47	44.16	44.35	44.53	44.72	44.91	45.36	45.83	46.30	46.77	47.25	47.73	48.22	48.71	49.21	49.71	50.22	50.73	51.25	51.77	52.30
Other	34.94	34.09	34.36	34.62	34.89	35.15	35.42	35.70	26.88	26.30	25.70	25.04	24.39	23.73	23.05	22.36	21.65	21.53	21.45	21.40	21.39	21.48	21.70	21.94	22.22	22.51	22.82
High GWP Gases	149.48	160.22	169.04	178.36	188.19	198.56	209.50	221.04	214.00	221.62	229.56	237.64	242.75	248.62	254.76	261.15	267.79	280.95	295.00	309.86	325.59	342.51	360.75	379.87	400.03	421.13	443.26
Total Other Greenhouse Gas Emissions	1181.36	1201.97	1216.01	1226.98	1240.59	1253.95	1267.87	1281.95	1206.11	1211.49	1217.16	1222.71	1225.92	1227.48	1228.53	1229.35	1236.02	1260.97	1284.69	1307.86	1329.32	1351.54	1374.14	1395.46	1417.04	1439.27	1466.81

Note: Totals may not equal sum of components due to independent rounding. Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
N/A = Not applicable.
Sources: 2004 and 2005 emissions and emission factors: Energy Information Administration (EIA), Emissions of Greenhouse Gases in the United States 2005, DOE/EIA-0573(2005) (Washington, DC, November 2006). Projections: EIA, AEO2007 National Energy Modeling System run s280cc70.d060207a.

HEARING EXHIBIT 2008-0004

Table 21 Greenhouse Gas Emissions Results
(2005 dollars per million Btu)
(million metric tons carbon dioxide equivalent)

Attachment POD-1 h Table 21 Greenhouse Gas Emission Results S 280 - Commercial Covered Case

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Allowance Price																											
Emission Price (2005 dollars per ton)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	13.09	13.80	14.44	15.02	15.84	17.11	18.47	19.95	21.55	23.27	25.13	27.15	29.32	31.66	34.20	36.93	39.89	43.08	46.52
Emission Price (nominal dollars per ton)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	15.13	16.26	17.32	18.32	19.69	21.65	23.82	26.24	28.86	31.77	35.02	38.57	42.51	46.85	51.62	56.88	62.72	69.11	76.22
Offset Price (2005 dollars per ton)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	13.09	13.80	14.44	15.02	15.84	17.11	18.47	19.95	21.30	19.11	17.53	16.30	15.34	14.57	15.75	16.97	18.23	19.52	19.75
Greenhouse Gas Emissions Cap Compliance																											
Covered Energy-Related Carbon Dioxide	5220.57	5241.59	5465.17	5481.05	5456.05	5478.39	5514.80	5556.01	5557.61	5568.71	5588.52	5609.25	5624.35	5618.29	5618.86	5608.81	5604.39	5577.12	5551.48	5528.88	5508.13	5471.48	5427.03	5350.24	5259.75	5143.75	5052.54
Covered Other Greenhouse Gas Emissions	317.22	323.16	334.21	342.08	352.39	362.32	372.67	383.84	346.57	353.81	359.52	365.91	370.61	375.15	379.81	385.04	390.86	403.10	416.97	431.58	447.21	464.29	483.19	503.09	523.77	545.12	567.24
Offsets Purchased	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	230.86	248.43	272.60	301.26	401.76	583.69	617.77	1109.72	1418.47	1417.89	1420.51	1420.85	1419.31	1420.12	1418.89	1418.55	1419.54	1419.42	1052.56
Noncovered Gases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	44.29	48.20	52.22	56.32	60.65	68.48	77.03	86.37	95.54	88.75	84.31	81.33	80.50	81.30	83.47	88.60	93.85	99.07	100.01
Domestic Agriculture/Forestry Sequestration	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	87.75	98.86	110.29	121.92	138.50	163.49	193.55	229.23	267.05	244.10	226.58	212.22	200.57	191.10	229.83	269.84	309.83	349.59	365.91
International Offsets	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	98.82	101.36	110.08	123.02	202.60	351.72	547.19	794.12	1055.87	1085.04	1109.62	1127.29	1138.23	1147.72	1105.60	1060.11	1015.86	970.75	586.64
Covered Emissions Less Offsets	5537.79	5564.74	5799.38	5823.12	5808.44	5840.71	5887.47	5939.85	5675.32	5674.10	5675.44	5673.90	5593.21	5409.75	5180.91	4884.13	4576.78	4562.32	4547.94	4539.61	4536.03	4515.65	4491.32	4434.77	4363.99	4269.45	4567.22
Covered Emissions Goal	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	5676.73	5676.73	5676.73	5676.73	5676.73	5676.73	5676.73	5676.73	4730.73	4730.73	4730.73	4730.73	4730.73	4730.73	4730.73	4730.73	4730.73	4730.73	3507.53
Allowance Banking (borrowing)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.00	0.00	0.00	0.00	83.53	266.98	495.82	792.60	153.95	168.41	182.80	191.12	194.70	215.09	239.41	295.96	366.75	461.28	-1059.69
Cumulative Bank Balance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.00	0.00	0.00	0.00	83.53	350.51	846.33	1638.94	1792.89	1961.30	2144.09	2335.21	2529.92	2745.00	2984.41	3280.37	3647.12	4108.40	3048.71
Total Energy-Related Carbon Dioxide Emissions	5923.13	5945.32	5932.18	5968.03	5947.43	5972.22	6011.86	6055.53	6060.58	6073.27	6094.75	6116.94	6134.28	6127.61	6128.98	6119.66	6117.67	6089.79	6063.92	6041.09	6021.48	5984.47	5940.71	5864.31	5774.61	5658.05	5567.45
Total Other Greenhouse Gases	1181.36	1201.97	1216.01	1227.01	1240.59	1253.93	1267.84	1281.94	1206.26	1211.52	1217.20	1223.55	1229.06	1230.98	1232.37	1233.62	1235.68	1260.22	1284.10	1307.34	1329.54	1351.63	1374.25	1395.00	1416.50	1438.75	1466.17
Total GHG Emissions	7104.50	7147.29	7148.19	7195.04	7188.02	7226.16	7279.70	7337.47	7266.83	7284.79	7311.95	7340.50	7363.33	7358.59	7361.35	7353.28	7353.35	7350.01	7348.02	7348.43	7351.02	7336.10	7314.97	7259.31	7191.10	7096.81	7033.63
Other Greenhouse Gases																											
(million metric tons)																											
Baseline Emissions Assumed																											
Methane	606.54	611.87	613.58	615.40	617.32	619.35	621.48	622.77	624.14	625.58	627.09	628.68	632.01	635.40	638.85	642.37	645.94	649.58	653.28	657.05	660.88	664.78	668.76	672.80	676.91	681.10	685.36
Landfills	148.85	155.73	154.48	153.24	152.01	150.79	149.59	149.28	148.97	148.67	148.36	148.06	147.91	147.75	147.60	147.45	147.30	147.14	146.99	146.84	146.69	146.54	146.39	146.23	146.08	145.93	145.78
Coal Mines	67.34	65.52	64.48	63.46	62.46	61.47	60.50	59.36	58.23	57.13	56.06	55.00	54.99	54.99	54.98	54.98	54.97	54.97	54.96	54.96	54.95	54.95	54.94	54.94	54.93	54.93	54.92
Natural Gas	154.75	154.05	157.46	160.94	164.50	168.14	171.87	174.82	177.83	180.88	183.99	187.16	190.48	193.86	197.30	200.80	204.37	207.99	211.68	215.44	219.26	223.16	227.12	231.15	235.25	239.42	243.67
Other	235.61	236.58	237.16	237.75	238.35	238.94	239.53	239.32	239.11	238.89	238.68	238.47	238.64	238.80	238.97	239.14	239.31	239.47	239.64	239.81	239.98	240.14	240.31	240.48	240.65	240.82	240.99
Non-Energy Carbon Dioxide	65.47	63.33	66.32	65.64	66.86	67.14	67.25	67.74	66.69	67.29	67.99	68.91	69.93	70.26	70.47	71.00	71.88	72.47	73.03	73.44	73.92	74.61	75.21	75.90	76.32	76.34	76.12
Nitrous Oxide	359.87	366.56	367.06	367.62	368.23	368.89	369.61	370.38	372.05	373.72	375.41	377.10	379.19	381.30	383.42	385.56	387.71	389.87	392.05	394.24	396.44	398.66	400.89	403.13	405.39	407.67	409.96
Agriculture	272.89	279.87	281.62	283.38	285.15	286.93	288.72	290.52	291.72	292.93	294.15	295.37	296.71	298.06	299.42	300.79	302.16	303.53	304.91	306.30	307.70	309.10	310.51	311.92	313.34	314.77	316.20
Mobile Combustion	52.05	52.59	51.08	49.62	48.19	46.81	45.47	44.16	44.35	44.53	44.72	44.91	45.36	45.83	46.30	46.77	47.25	47.73	48.22	48.71	49.21	49.71	50.22	50.73	51.25	51.77	52.30
Other	34.94	34.09	34.36	34.62	34.89	35.15	35.42	35.70	35.97	36.26	36.54	36.82	37.12	37.41	37.71	38.01	38.31	38.61	38.92	39.23	39.54	39.85	40.17	40.49	40.81	41.13	41.46
High GWP Gases	149.48	160.22	169.04	178.36	188.19	198.56	209.50	221.04	232.54	244.64	257.36	270.75	282.84	295.47	308.66	322.45	336.85	351.89	367.60	384.02	401.17	419.08	437.80	457.35	477.77	499.10	521.39
Total Baseline	1181.36	1201.97	1216.01	1227.01	1240.59	1253.93	1267.84	1281.94	1295.42	1311.23	1327.85	1345.44	1363.98	1382.44	1401.41	1421.37	1442.38	1463.81	1485.96	1508.74	1532.40	1557.13	1582.65	1609.18	1636.40	1664.21	1692.83
Abatement and Offsets																											
Methane	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	54.65	59.06	63.59	68.21	72.44	79.96	88.08	96.84	105.44	100.04	96.56	94.29	94.00	95.13	97.05	101.93	106.89	111.81	113.14
Landfills	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	29.68	32.03	34.45	36.91	39.09	43.50	48.26	53.40	58.38	54.20	51.45	49.57	49.11	49.72	50.78	53.95	57.23	60.52	61.44
Coal Mines	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	17.29	18.52	19.78	21.07	22.05	23.15	24.26	25.37	26.50	27.28	27.91	28.49	29.02	29.44	29.60	29.73	29.82	29.87	29.91
Natural Gas	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	5.62	6.18	6.75	7.34	7.96	9.39	10.98	12.75	14.51	12.91	11.79	10.97	10.69	10.82	11.05	12.16	13.33	14.51	14.81
Other	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	2.07	2.34	2.61	2.90	3.33	3.93	4.59	5.32	6.05	5.65	5.41	5.26	5.18	5.15	5.63	6.09	6.51	6.91	6.98
Non-Energy Carbon Dioxide	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nitrous Oxide	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	16.02	17.61	19.25	20.91	22.88	25.23	27.73	30.40	33.11	32.98	33.06	33.28	33.60	33.95	34.45	34.93	35.36	35.75	35.43
Agriculture	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	6.93	7.66	8.41	9.17	10.26	11.66	13.20	14.89	16.60	15.98	15.67	15.53	15.52	15.61	16.01	16.40	16.78	17.13	16.79
Mobile Combustion	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	9.09	9.95	10.84	11.74	12.62	13.57	14.53	15.51	16.51	17.00	17.39	17.75	18.08	18.34	18.44	18.52	18.58	18.61	18.64
High GWP Gases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	18.49	23.03	27.80	32.76	39.60	46.27	53.23	60.50	68.14	70.57	72.25	73.82	75.26	76.42	76.90	77.33	77.65	77.89	78.09
Total Reductions	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	89.16	99.71	110.64	121.88	134.92	151.46	169.04	187.75	206.69	203.59	201.86	201.39	202.87	205.50	208.40	214.18	219.90	225.45	226.66
Resulting Emissions																											
Methane	606.54	611.87	613.58	615.40	617.32	619.35	621.48	622.77	569.49	566.52	563.50	560.47	559.58	555.44	550.77	545.52	540.50	549.53	556.72	562.75	566.88	569.65	571.70	570.87	570.02	569.29	572.23
Landfills	148.85	155.73	154.48	153.24	152.01	150.79	149.59	149.28	119.29	116.64	113.92	111.15	108.81	104.26	99.34	94.04	88.91	92.94	95.54	97.27	97.58	96.82	95.61	92.29	88.86	85.41	84.34
Coal Mines	67.34	65.52	64.48	63.46	62.46	61.47	60.50	59.36	40.94	38.62	36.28	33.93	32.94	31.84	30.73	29.60	28.47	27.69	27.05	26.47	25.93	25.51	25.35	25.21	25.11	25.05	25.01
Natural Gas	154.75	154.05	157.46	160.94	164.50	168.14	171.87	174.82	172.21	174.71	177.24	179.82	182.52	184.47	186.32	188.05	189.85	195.09	199.90	204.47	208.57	212.33	216.06	218.98	221.92	224.91	228.87
Other	235.61	236.58	237.16	237.75	238.35	238.94	239.53	239.32	237.04	236.56	236.07	235.57	235.30	234.88	234.38	233.82	233.26	233.82	234.23	234.55	234.79	234.99	234.68	234.39	234.14	233.91	234.00
Non-Energy Carbon Dioxide	65.47	63.33	66.32	65.64	66.86	67.14	67.25	67.74	66.69	67.29	67.99	68.91	69.93	70.26	70.47	71.00	71.88	72.47	73.03	73.44	73.92	74.61	75.21	75.90	76.32	76.34	76.12
Nitrous Oxide	359.87	366.56	367.06	367.62	368.23	368.89	369.61	370.38	356.03	356.11	356.16	356.19	356.31	356.07	355.69	355.15	354.60	356.89	358.99	360.95	362.84	364.71	366.44	368.21	370.04	371.92	374.53
Agriculture	272.89	279.87	281.62	283.38	285.15	286.93	288.72	290.52	284.80	285.28	285.74	286.20	286.45	286.40	286.22	285.89	285.55	287.55	289.25	290.77	292.18	293.49	294.50	295.52	296.56	297.63	299.41
Mobile Combustion	52.05	52.59	51.08	49.62	48.19	46.81	45.47	44.16	44.35	44.53	44.72	44.91	45.36	45.83	46.30	46.77	47.25	47.73	48.22	48.71	49.21	49.71	50.22	50.73	51.25	51.77	52.30
Other	34.94	34.09	34.36	34.62	34.89	35.15	35.42	35.70	26.89	26.30	25.70	25.08	24.50	23.84	23.18	22.49	21.80	21.61	21.53	21.47	21.45	21.51	21.73	21.96	22.23	22.52	22.82
High GWP Gases	149.48	160.22	169.04	178.36	188.19	198.56	209.50	221.04	214.04	221.60	229.56	237.99	243.24	249.20	255.44	261.94	268.71	281.32	295.35	310.20	325.91	342.67	360.90	380.02	400.12	421.21	443.30
Total Other Greenhouse Gas Emissions	1181.36	1201.97	1216.01	1227.01	1240.59	1253.93	1267.84	1281.94	1206.26	1211.52	1217.20	1223.55	1229.06	1230.98	1232.37	1233.62	1235.68	1260.22	1284.10	1307.34	1329.54	1351.63	1374.25	1395.00	1416.50	1438.75	1466.17

Note: Totals may not equal sum of components due to independent rounding. Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
N/A = Not applicable.
Sources: 2004 and 2005 emissions and emission factors: Energy Information Administration (EIA), Emissions of Greenhouse Gases in the United States 2005, DOE/EIA-0573(2005) (Washington, DC, November 2006). Projections: EIA, AEO2007 National Energy Modeling System run s280comm d061507a.

HEARING EXHIBIT - 00000008

Table 21 Greenhouse Gas Emissions Results
(2005 dollars per million Btu)
(million metric tons carbon dioxide equivalent)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Allowance Price																											
Emission Price (2005 dollars per ton)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Emission Price (nominal dollars per ton)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Offset Price (2005 dollars per ton)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Greenhouse Gas Emissions Cap Compliance																											
Covered Energy-Related Carbon Dioxide	5220.57	5241.59	5246.94	5240.28	5264.90	5304.69	5350.64	5394.64	5438.08	5479.78	5530.55	5573.31	5613.62	5646.83	5686.42	5730.78	5774.49	5822.88	5874.69	5928.74	5991.08	6055.39	6130.58	6215.92	6289.02	6376.28	6461.85
Covered Other Greenhouse Gas Emissions	317.22	323.16	336.98	347.80	361.18	374.32	388.05	401.70	413.36	425.62	438.17	451.56	465.48	479.34	493.72	509.06	525.21	541.66	558.75	576.31	594.62	613.91	633.78	654.51	675.91	697.78	720.67
Offsets Purchased	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Noncovered Gases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Domestic Agriculture/Forestry Sequestration	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
International Offsets	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Covered Emissions Less Offsets	5537.79	5564.74	5583.92	5588.08	5626.09	5679.01	5738.69	5796.34	5851.44	5905.40	5968.72	6024.87	6079.10	6126.17	6180.14	6239.84	6299.70	6364.54	6433.44	6505.05	6585.69	6669.30	6764.36	6870.43	6964.93	7074.06	7182.52
Covered Emissions Goal	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Allowance Banking (borrowing)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Cumulative Bank Balance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Energy-Related Carbon Dioxide Emissions	5923.13	5945.32	5935.30	5951.13	5984.94	6030.45	6082.32	6132.92	6183.11	6230.12	6283.99	6329.75	6373.27	6406.50	6447.94	6494.62	6541.90	6591.47	6644.07	6700.01	6765.11	6831.26	6908.82	6996.60	7073.12	7162.45	7251.81
Total Other Greenhouse Gases	1181.36	1201.97	1220.48	1236.13	1254.49	1272.75	1291.75	1310.33	1327.90	1346.18	1364.86	1384.48	1406.12	1427.85	1450.23	1473.72	1498.18	1523.09	1548.79	1575.12	1602.37	1630.78	1659.93	1690.11	1721.16	1752.86	1785.76
Total GHG Emissions	7104.50	7147.29	7155.78	7187.26	7239.43	7303.20	7374.07	7443.25	7511.01	7576.30	7648.85	7714.23	7779.39	7834.35	7898.18	7968.34	8040.08	8114.56	8192.86	8275.13	8367.48	8462.04	8568.75	8686.71	8794.28	8915.31	9037.57
Other Greenhouse Gases (million metric tons)																											
Baseline Emissions Assumed																											
Methane	606.54	611.87	617.10	622.42	627.85	633.39	639.03	643.08	647.23	651.48	655.84	660.30	666.73	673.29	680.00	686.84	693.82	700.96	708.24	715.68	723.27	731.03	738.95	747.04	755.31	763.75	772.38
Landfills	148.85	155.73	155.87	156.01	156.14	156.28	156.42	157.00	157.57	158.15	158.73	159.31	160.11	160.93	161.74	162.56	163.38	164.21	165.04	165.88	166.72	167.57	168.42	169.27	170.13	170.99	171.85
Coal Mines	67.34	65.52	66.30	67.09	67.89	68.70	69.52	69.14	68.76	68.39	68.02	67.65	68.16	68.68	69.20	69.73	70.26	70.79	71.33	71.87	72.42	72.97	73.53	74.08	74.65	75.22	75.79
Natural Gas	154.75	154.05	157.77	161.58	165.48	169.47	173.56	177.63	181.79	186.05	190.41	194.87	199.82	204.89	210.08	215.41	220.88	226.48	232.22	238.11	244.15	250.35	256.70	263.21	269.88	276.73	283.75
Other	235.61	236.58	237.16	237.75	238.35	238.94	239.53	239.32	239.11	238.89	238.68	238.47	238.64	238.80	238.97	239.14	239.31	239.47	239.64	239.81	239.98	240.14	240.31	240.48	240.65	240.82	240.99
Non-Energy Carbon Dioxide	65.47	63.33	66.32	65.70	67.00	67.37	67.60	68.20	69.15	70.19	70.99	72.06	73.33	74.04	74.72	75.80	77.10	78.10	79.10	79.90	80.77	81.90	82.85	83.88	84.76	85.27	85.90
Nitrous Oxide	359.87	366.56	367.06	367.62	368.23	368.89	369.61	370.38	372.05	373.72	375.41	377.10	379.19	381.30	383.42	385.56	387.71	389.87	392.05	394.24	396.44	398.66	400.89	403.13	405.39	407.67	409.96
Agriculture	272.89	279.87	281.62	283.38	285.15	286.93	288.72	290.52	291.72	292.93	294.15	295.37	296.71	298.06	299.42	300.79	302.16	303.53	304.91	306.30	307.70	309.10	310.51	311.92	313.34	314.77	316.20
Mobile Combustion	52.05	52.59	51.08	49.62	48.19	46.81	45.47	44.16	44.35	44.53	44.72	44.91	45.36	45.83	46.30	46.77	47.25	47.73	48.22	48.71	49.21	49.71	50.22	50.73	51.25	51.77	52.30
Other	34.94	34.09	34.36	34.62	34.89	35.15	35.42	35.70	35.97	36.26	36.54	36.82	37.12	37.41	37.71	38.01	38.31	38.61	38.92	39.23	39.54	39.85	40.17	40.49	40.81	41.13	41.46
High GWP Gases	149.48	160.22	170.00	180.39	191.41	203.10	215.51	228.68	239.47	250.78	262.62	275.03	286.87	299.21	312.09	325.53	339.54	354.16	369.40	385.31	401.89	419.19	437.24	456.06	475.69	496.17	517.53
Total Baseline	1181.36	1201.97	1220.48	1236.13	1254.49	1272.75	1291.75	1310.33	1327.90	1346.18	1364.86	1384.48	1406.12	1427.85	1450.23	1473.72	1498.18	1523.09	1548.79	1575.12	1602.37	1630.78	1659.93	1690.11	1721.16	1752.86	1785.76
Abatement and Offsets																											
Methane	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Landfills	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Coal Mines	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Natural Gas	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Other	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Non-Energy Carbon Dioxide	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Nitrous Oxide	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Agriculture	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Mobile Combustion	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Other	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
High GWP Gases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Reductions	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Resulting Emissions																											
Methane	606.54	611.87	617.10	622.42	627.85	633.39	639.03	643.08	647.23	651.48	655.84	660.30	666.73	673.29	680.00	686.84	693.82	700.96	708.24	715.68	723.27	731.03	738.95	747.04	755.31	763.75	772.38
Landfills	148.85	155.73	155.87	156.01	156.14	156.28	156.42	157.00	157.57	158.15	158.73	159.31	160.11	160.93	161.74	162.56	163.38	164.21	165.04	165.88	166.72	167.57	168.42	169.27	170.13	170.99	171.85
Coal Mines	67.34	65.52	66.30	67.09	67.89	68.70	69.52	69.14	68.76	68.39	68.02	67.65	68.16	68.68	69.20	69.73	70.26	70.79	71.33	71.87	72.42	72.97	73.53	74.08	74.65	75.22	75.79
Natural Gas	154.75	154.05	157.77	161.58	165.48	169.47	173.56	177.63	181.79	186.05	190.41	194.87	199.82	204.89	210.08	215.41	220.88	226.48	232.22	238.11	244.15	250.35	256.70	263.21	269.88	276.73	283.75
Other	235.61	236.58	237.16	237.75	238.35	238.94	239.53	239.32	239.11	238.89	238.68	238.47	238.64	238.80	238.97	239.14	239.31	239.47	239.64	239.81	239.98	240.14	240.31	240.48	240.65	240.82	240.99
Non-Energy Carbon Dioxide	65.47	63.33	66.32	65.70	67.00	67.37	67.60	68.20	69.15	70.19	70.99	72.06	73.33	74.04	74.72	75.80	77.10	78.10	79.10	79.90	80.77	81.90	82.85	83.88	84.76	85.27	85.90
Nitrous Oxide	359.87	366.56	367.06	367.62	368.23	368.89	369.61	370.38	372.05	373.72	375.41	377.10	379.19	381.30	383.42	385.56	387.71	389.87	392.05	394.24	396.44	398.66	400.89	403.13	405.39	407.67	409.96
Agriculture	272.89	279.87	281.62	283.38	285.15	286.93	288.72	290.52	291.72	292.93	294.15	295.37	296.71	298.06	299.42	300.79	302.16	303.53	304.91	306.30	307.70	309.10	310.51	311.92	313.34	314.77	316.20
Mobile Combustion	52.05	52.59	51.08	49.62	48.19	46.81	45.47	44.16	44.35	44.53	44.72	44.91	45.36	45.83	46.30	46.77	47.25	47.73	48.22	48.71	49.21	49.71	50.22	50.73	51.25	51.77	52.30
Other	34.94	34.09	34.36	34.62	34.89	35.15	35.42	35.70	35.97	36.26	36.54	36.82	37.12	37.41	37.71	38.01	38.31	38.61	38.92	39.23	39.54	39.85	40.17	40.49	40.81	41.13	41.46
High GWP Gases	149.48	160.22	170.00	180.39	191.41	203.10	215.51	228.68	239.47	250.78	262.62	275.03	286.87	299.21	312.09	325.53	339.54	354.16	369.40	385.31	401.89	419.19	437.24	456.06	475.69	496.17	517.53
Total Other Greenhouse Gas Emissions	1181.36	1201.97	1220.48	1236.13	1254.49	1272.75	1291.75	1310.33	1327.90	1346.18	1364.86	1384.48	1406.12	1427.85	1450.23	1473.72	1498.18	1523.09	1548.79	1575.12	1602.37	1630.78	1659.93	1690.11	1721.16	1752.86	1785.76

Note: Totals may not equal sum of components due to independent rounding. Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
N/A = Not applicable.
Sources: 2004 and 2005 emissions and emission factors: Energy Information Administration (EIA), Emissions of Greenhouse Gases in the United States 2005, DOE/EIA-0573(2005) (Washington, DC, November 2006). Projections: EIA, AEO2007 National Energy Modeling System run htrkiten d060107a.

HEARING EXHIBIT - 00000209

Table 21 Greenhouse Gas Emissions Results
(2005 dollars per million Btu)
(million metric tons carbon dioxide equivalent)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Allowance Price																											
Emission Price (2005 dollars pe	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	14.06	14.65	15.51	16.75	18.09	19.54	21.10	22.79	24.61	26.58	28.71	31.01	33.49	36.16	39.06	42.18	45.56	49.20	53.14
Emission Price (nominal dollars	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	16.25	17.27	18.62	20.48	22.53	24.79	27.27	30.03	33.03	36.36	40.08	44.16	48.69	53.69	59.17	65.27	72.01	79.38	87.59
Offset Price (2005 dollars per	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	14.06	14.65	15.51	16.75	18.09	19.54	21.10	22.79	20.86	18.76	17.20	16.02	15.09	14.35	15.52	16.73	18.00	19.28	19.49
Greenhouse Gas Emissions Cap Compliance																											
Covered Energy-Related Carbon Diox	5220.57	5241.59	5245.60	5258.60	5269.72	5307.72	5349.10	5393.31	5401.91	5415.20	5393.28	5411.52	5431.04	5432.16	5418.68	5422.26	5423.83	5423.35	5414.37	5386.79	5347.99	5324.59	5263.98	5191.78	5077.18	4944.61	4777.44
Covered Other Greenhouse Gas Emiss	317.22	323.16	334.21	342.08	352.35	362.29	372.67	383.81	347.17	352.28	357.01	362.40	366.89	370.99	375.22	380.11	386.89	400.10	414.00	428.69	444.74	462.12	480.94	500.78	521.41	542.76	565.02
Offsets Purchased	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	322.41	337.38	395.37	510.04	696.47	936.54	1236.16	1593.52	1337.19	1338.43	1337.17	1337.95	1338.11	1338.76	1338.72	1336.85	1339.16	1337.86	963.18
Noncovered Gases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	45.18	49.09	53.48	60.64	68.68	77.47	87.08	97.06	93.77	87.27	82.97	80.15	80.10	80.93	83.12	87.65	92.91	98.12	98.97
Domestic Agriculture/Forestry Se	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	93.90	104.76	118.33	136.85	162.08	192.52	228.74	271.51	259.98	237.77	220.38	206.40	195.43	186.14	224.96	264.61	304.70	344.40	360.23
International Offsets	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	183.33	183.53	223.56	312.55	465.71	666.55	920.34	1224.94	983.44	1013.36	1033.82	1051.41	1062.58	1071.69	1030.64	984.60	941.56	895.34	503.98
Covered Emissions Less Offsets	5537.79	5564.74	5579.80	5600.67	5622.07	5670.00	5721.77	5777.12	5426.67	5430.11	5354.92	5263.89	5101.46	4866.61	4557.73	4208.85	4473.53	4485.04	4491.20	4477.52	4454.62	4447.94	4406.20	4355.72	4259.43	4149.51	4379.28
Covered Emissions Goal	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	5428.87	5428.87	5428.87	5428.87	5428.87	5428.87	5428.87	5428.87	4460.50	4460.50	4460.50	4460.50	4460.50	4460.50	4460.50	4460.50	4460.50	4460.50	3209.43
Allowance Banking (borrowing)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.00	0.00	73.94	164.98	327.41	562.25	871.13	1220.02	-13.03	-24.54	-30.70	-17.02	5.88	12.56	54.30	104.78	201.07	310.99	-1169.84
Cumulative Bank Balance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.00	0.00	73.94	238.92	566.33	1128.58	1999.72	3219.73	3206.71	3182.16	3151.47	3134.45	3140.33	3152.88	3207.18	3311.97	3513.04	3824.03	2654.18
Total Energy-Related Carbon Dioxide	5923.13	5945.32	5933.96	5971.58	5992.17	6036.45	6083.87	6135.11	6151.86	6171.78	6153.48	6175.78	6199.93	6202.41	6192.35	6198.82	6205.21	6206.95	6199.96	6174.48	6139.09	6119.41	6062.66	5993.82	5883.61	5754.22	5591.94
Total Other Greenhouse Gases	1181.36	1201.97	1216.01	1227.01	1240.55	1253.90	1267.84	1281.91	1203.97	1209.10	1213.44	1215.72	1217.31	1217.83	1217.72	1217.99	1233.49	1258.69	1282.48	1305.64	1327.47	1349.83	1372.36	1393.65	1415.07	1437.35	1464.99
Total GHG Emissions	7104.50	7147.29	7149.97	7198.59	7232.72	7290.35	7351.70	7417.02	7355.83	7380.88	7366.92	7391.51	7417.23	7420.24	7410.07	7416.81	7438.69	7465.64	7482.44	7480.12	7466.56	7469.24	7435.02	7387.47	7298.69	7191.57	7056.93
Other Greenhouse Gases																											
(million metric tons)																											
Baseline Emissions Assumed																											
Methane	606.54	611.87	613.58	615.40	617.32	619.35	621.48	622.77	624.14	625.58	627.09	628.68	632.01	635.40	638.85	642.37	645.94	649.58	653.28	657.05	660.88	664.78	668.76	672.80	676.91	681.10	685.36
Landfills	148.85	155.73	154.48	153.24	152.01	150.79	149.59	149.28	148.97	148.67	148.36	148.06	147.91	147.75	147.60	147.45	147.30	147.14	146.99	146.84	146.69	146.54	146.39	146.23	146.08	145.93	145.78
Coal Mines	67.34	65.52	64.48	63.46	62.46	61.47	60.50	59.36	58.23	57.13	56.06	55.00	54.99	54.99	54.98	54.98	54.97	54.97	54.96	54.96	54.95	54.95	54.94	54.94	54.93	54.93	54.92
Natural Gas	154.75	154.05	157.46	160.94	164.50	168.14	171.87	174.82	177.83	180.88	183.99	187.16	190.48	193.86	197.30	200.80	204.37	207.99	211.68	215.44	219.26	223.16	227.12	231.15	235.25	239.42	243.67
Other	235.61	236.58	237.16	237.75	238.35	238.94	239.53	239.32	239.11	238.89	238.68	238.47	238.64	238.80	238.97	239.14	239.31	239.47	239.64	239.81	239.98	240.14	240.31	240.48	240.65	240.82	240.99
Non-Energy Carbon Dioxide	65.47	63.33	66.32	65.63	66.81	67.11	67.25	67.71	66.52	67.08	67.45	68.22	69.11	69.40	69.61	70.11	70.96	71.64	72.15	72.40	72.69	73.30	73.74	74.11	74.35	74.25	74.05
Nitrous Oxide	359.87	366.56	367.06	367.62	368.23	368.89	369.61	370.38	372.05	373.72	375.41	377.10	379.19	381.30	383.42	385.56	387.71	389.87	392.05	394.24	396.44	398.66	400.89	403.13	405.39	407.67	409.96
Agriculture	272.89	279.87	281.62	283.38	285.15	286.93	288.72	290.52	291.72	292.93	294.15	295.37	296.71	298.06	299.42	300.79	302.16	303.53	304.91	306.30	307.70	309.10	310.51	311.92	313.34	314.77	316.20
Mobile Combustion	52.05	52.59	51.08	49.62	48.19	46.81	45.47	44.16	44.35	44.53	44.72	44.91	45.36	45.83	46.30	46.77	47.25	47.73	48.22	48.71	49.21	49.71	50.22	50.73	51.25	51.77	52.30
Other	34.94	34.09	34.36	34.62	34.89	35.15	35.42	35.70	35.97	36.26	36.54	36.82	37.12	37.41	37.71	38.01	38.31	38.61	38.92	39.23	39.54	39.85	40.17	40.49	40.81	41.13	41.46
High GWP Gases	149.48	160.22	169.04	178.36	188.19	198.56	209.50	221.04	232.54	244.64	257.36	270.75	282.84	295.47	308.66	322.45	336.85	351.89	367.60	384.02	401.17	419.08	437.80	457.35	477.77	499.10	521.39
Total Baseline	1181.36	1201.97	1216.01	1227.01	1240.55	1253.90	1267.84	1281.91	1295.24	1311.02	1327.31	1344.75	1363.16	1381.58	1400.55	1420.48	1441.46	1462.97	1485.07	1507.70	1531.18	1555.82	1581.10	1607.39	1634.43	1662.13	1690.76
Abatement and Offsets																											
Methane	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	55.45	59.88	64.77	72.36	80.10	88.45	97.49	106.70	104.55	99.28	95.89	93.71	94.03	95.10	97.01	101.22	106.16	111.04	112.27
Landfills	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	30.04	32.41	34.99	39.38	43.93	48.84	54.16	59.46	57.37	53.37	50.69	48.91	48.98	49.61	50.67	53.42	56.70	59.99	60.85
Coal Mines	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	17.50	18.74	20.09	21.63	22.75	23.88	25.02	26.16	27.12	27.77	28.38	28.90	29.29	29.61	29.74	29.81	29.87	29.90	29.92
Natural Gas	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	5.69	6.25	6.86	8.07	9.54	11.18	13.00	14.95	14.15	12.60	11.51	10.73	10.66	10.80	11.03	11.97	13.13	14.31	14.58
Other	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	2.22	2.49	2.82	3.28	3.88	4.56	5.30	6.13	5.92	5.54	5.31	5.17	5.10	5.08	5.56	6.02	6.45	6.84	6.91
Non-Energy Carbon Dioxide	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nitrous Oxide	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	16.43	18.02	19.82	21.96	24.35	26.89	29.61	32.51	33.24	33.06	33.14	33.35	33.60	33.90	34.39	34.82	35.24	35.61	35.27
Agriculture	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	7.23	7.95	8.81	9.91	11.33	12.90	14.62	16.52	16.34	15.76	15.46	15.34	15.35	15.45	15.86	16.24	16.62	16.98	16.62
Mobile Combustion	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	9.20	10.07	11.01	12.05	13.01	13.99	14.99	15.99	16.90	17.30	17.68	18.01	18.25	18.45	18.53	18.58	18.61	18.63	18.65
High GWP Gases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	19.39	24.02	29.29	34.71	41.41	48.41	55.73	63.29	70.19	71.93	73.57	75.00	76.07	77.00	77.43	77.71	77.96	78.11	78.23
Total Reductions	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	91.28	101.92	113.87	129.03	145.85	163.75	182.83	202.49	207.97	204.28	202.60	202.06	203.70	206.00	208.82	213.75	219.36	224.77	225.77
Resulting Emissions																											
Methane	606.54	611.87	613.58	615.40	617.32	619.35	621.48	622.77	568.69	565.70	562.33	556.33	551.92	546.95	541.37	535.67	541.39	550.29	557.39	563.34	566.85	569.69	571.75	571.58	570.76	570.06	573.09
Landfills	148.85	155.73	154.48	153.24	152.01	150.79	149.59	149.28	118.93	116.26	113.37	108.68	103.98	98.91	93.44	87.99	89.93	93.78	96.30	97.93	97.71	96.93	95.71	92.81	89.38	85.94	84.93
Coal Mines	67.34	65.52	64.48	63.46	62.46	61.47	60.50	59.36	40.73	38.40	35.96	33.37	32.24	31.11	29.96	28.82	27.85	27.20	26.58	26.05	25.67	25.33	25.20	25.12	25.06	25.02	25.00
Natural Gas	154.75	154.05	157.46	160.94	164.50	168.14	171.87	174.82	172.14	174.63	177.13	179.09	180.94	182.68	184.30	185.85	190.21	195.39	200.17	204.71	208.60	212.36	216.09	219.18	222.12	225.11	229.09
Other	235.61	236.58	237.16	237.75	238.35	238.94	239.53	239.32	236.88	236.41	235.86	235.19	234.75	234.25	233.67	233.01	233.39	233.93	234.33	234.64	234.87	235.07	234.75	234.46	234.20	233.98	234.07
Non-Energy Carbon Dioxide	65.47	63.33	66.32	65.63	66.81	67.11	67.25	67.71	66.52	67.08	67.45	68.22	69.11	69.40	69.61	70.11	70.96	71.64	72.15	72.40	72.69	73.30	73.74	74.11	74.35	74.25	74.05
Nitrous Oxide	359.87	366.56	367.06	367.62	368.23	368.89	369.61	370.38	355.62	355.70	355.59	355.13	354.85	354.41	353.81	353.05	354.47	356.81	358.91	360.89	362.84	364.76	366.50	368.31	370.16	372.05	374.69
Agriculture	272.89	279.87	281.62	283.38	285.15	286.93	288.72	290.52	284.49	284.98	285.34	285.46	285.38	285.17	284.80	284.27	285.82	287.77	289.46	290.96	292.35	293.65	294.65	295.68	296.72	297.79	299.58
Mobile Combustion	52.05	52.59	51.08	49.62	48.19	46.81	45.47	44.16	44.35	44.53	44.72	44.91	45.36	45.83	46.30	46.77	47.25	47.73	48.22	48.71	49.21	49.71	50.22	50.73	51.25	51.77	52.30
Other	34.94	34.09	34.36	34.62	34.89	35.15	35.42	35.70	26.77	26.18	25.53	24.77	24.10	23.42	22.72	22.02	21.41	21.31	21.24	21.22	21.29	21.40	21.63	21.91	22.19	22.50	22.81
High GWP Gases	149.48	160.22	169.04	178.36	188.19	198.56	209.50	221.04	213.15	220.62	228.07	236.04	241.43	247.06	252.93	259.16	266.66	279.96	294.03	309.02	325.10	342.08	360.37	379.64	399.81	420.99	443.16
Total Other Greenhouse Gas Emiss	1181.36	1201.97	1216.01	1227.01	1240.55	1253.90	1267.84	1281.91	1203.97	1209.10	1213.44	1215.72	1217.31	1217.83	1217.72	1217.99	1233.49	1258.69	1282.48	1305.64	1327.47	1349.83	1372.36	1393.65	1415.07	1437.35	1464.99

Note: Totals may not equal sum of components due to independent rounding. Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
N/A = Not applicable.
Sources: 2004 and 2005 emissions and emission factors: Energy Information Administration (EIA), Emissions of Greenhouse Gases in the United States 2005, DOE/EIA-0573(2005) (Washington, DC, November 2006). Projections: EIA, AEO2007 National Energy Modeling System run s280nucbio.d092807a.

HEARING EXHIBIT - 00000000

Attachment POD-1.n. Table 3 Energy Prices by Sector and Source & Table 119
Unadjusted Energy Prices by Sector and Source

HEARING EXHIBIT 20000011

Table 3 Energy Prices by Sector and Source
(2005 dollars per million Btu, unless otherwise noted)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential																											
Liquefied Petroleum Gases	18.21	19.29	21.16	24.47	24.49	24.03	23.80	23.49	23.16	22.87	22.89	22.80	22.88	23.02	22.95	22.95	22.95	22.95	23.10	23.21	23.22	23.31	23.38	23.39	23.38	23.38	23.50
Distillate Fuel Oil	12.89	14.73	16.91	17.40	16.76	15.64	14.76	13.98	13.25	12.47	12.37	12.43	12.47	12.58	12.68	13.02	12.96	13.13	13.34	13.27	13.41	13.42	13.52	13.63	13.69	13.76	13.81
Natural Gas	10.72	12.43	13.04	11.77	11.73	11.31	11.09	10.80	10.49	10.21	10.24	10.15	10.23	10.39	10.30	10.30	10.31	10.34	10.50	10.63	10.65	10.76	10.84	10.89	10.86	10.88	11.00
Electricity	27.10	27.59	27.70	27.69	27.38	27.14	26.97	26.73	27.12	27.62	27.27	27.26	27.45	27.84	28.21	28.44	28.74	29.17	29.56	29.83	29.96	30.21	30.59	30.75	30.92	31.42	31.98
Commercial																											
Distillate Fuel Oil	10.48	12.68	14.63	15.18	14.26	13.27	12.63	11.97	11.25	10.79	10.53	10.59	10.72	10.74	10.84	11.22	11.14	11.31	11.65	11.36	11.67	11.91	11.82	11.96	12.30	12.23	12.49
Residual Fuel	6.25	8.41	10.10	7.90	7.97	7.67	7.54	7.07	6.91	5.97	6.30	6.48	6.44	6.58	6.69	6.98	7.06	7.22	7.37	7.23	7.36	7.16	7.29	7.39	7.45	7.22	7.30
Natural Gas	9.40	11.20	11.38	10.20	10.15	9.69	9.46	9.14	8.81	8.50	8.51	8.39	8.46	8.58	8.48	8.47	8.45	8.45	8.58	8.67	8.67	8.75	8.80	8.82	8.77	8.76	8.86
Electricity	24.59	25.25	25.80	25.55	25.30	24.94	24.62	24.17	24.56	25.21	24.96	25.02	25.28	25.74	26.17	26.44	26.69	27.08	27.45	27.74	27.82	27.98	28.32	28.31	28.41	28.97	29.49
Industrial 1/																											
Liquefied Petroleum Gases	11.18	16.98	18.96	17.45	17.38	16.82	16.56	16.17	16.23	16.02	16.02	15.95	16.09	16.27	16.30	16.38	16.38	16.45	16.63	16.77	16.88	17.04	17.18	17.28	17.34	17.45	17.67
Distillate Fuel Oil	10.99	13.08	15.14	15.34	14.13	13.27	12.87	12.51	12.82	12.65	12.30	12.43	12.73	12.74	12.95	13.51	13.47	13.77	14.31	14.05	14.63	15.20	15.18	15.56	16.33	16.36	17.03
Residual Fuel Oil	5.77	7.77	9.34	10.06	9.89	9.58	9.18	8.83	9.43	8.96	9.05	9.16	9.27	9.53	9.66	9.97	10.18	10.43	10.63	10.77	11.04	11.29	11.51	11.79	12.08	12.31	12.72
Natural Gas 2/	6.47	8.16	7.45	7.31	7.28	6.81	6.56	6.23	6.60	6.37	6.40	6.35	6.49	6.69	6.69	6.77	6.85	6.95	7.17	7.37	7.51	7.72	7.91	8.08	8.18	8.38	8.65
Metallurgical Coal	2.31	3.06	3.26	3.32	3.30	3.20	3.10	2.99	4.34	4.28	4.34	4.38	4.49	4.61	5.08	5.23	5.39	5.63	5.82	6.03	6.25	6.48	6.73	7.01	7.31	7.62	7.97
Other Industrial Coal	1.80	2.15	2.20	2.24	2.23	2.22	2.22	2.19	3.43	3.46	3.50	3.55	3.66	3.77	3.89	4.03	4.17	4.32	4.50	4.69	4.90	5.12	5.34	5.59	5.86	6.13	6.44
Coal to Liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	15.88	16.69	18.30	18.92	18.86	18.52	18.11	17.52	17.72	18.09	17.83	17.86	18.05	18.40	18.72	18.93	19.18	19.51	19.80	20.04	20.17	20.33	20.60	20.68	20.79	21.22	21.73
Biomass (remove for AEO tables)	0.00	0.00	0.00	0.00	0.00	1.38	1.52	1.37	1.30	1.27	1.28	1.25	1.24	1.24	1.25	1.28	1.29	1.29	1.34	1.41	1.58	1.67	1.86	2.00	1.92	1.91	1.83
Transportation																											
Liquefied Petroleum Gases 3/	19.68	23.92	26.81	22.67	22.79	22.38	24.48	24.17	24.65	24.37	24.42	24.35	24.48	24.69	24.67	24.73	24.83	24.94	25.20	25.42	25.56	25.78	26.01	26.19	26.36	26.56	26.89
E85 4/	20.91	23.10	24.81	28.94	27.18	25.60	24.80	23.86	23.23	22.39	22.01	21.08	21.23	20.81	20.94	21.14	21.00	21.05	21.50	21.52	21.74	21.87	21.96	22.14	22.40	22.60	23.08
Motor Gasoline 5/	15.72	18.64	21.15	21.42	19.74	18.51	18.03	17.28	17.71	17.61	16.91	17.04	17.27	17.07	17.43	18.06	17.72	17.96	18.55	18.49	18.92	19.43	19.39	19.85	20.48	20.62	21.22
Jet Fuel 6/	9.22	13.14	14.96	12.97	11.66	11.08	10.86	10.39	10.95	10.92	10.74	10.89	11.07	11.11	11.36	11.89	11.84	12.13	12.65	12.64	13.02	13.52	13.60	13.97	14.43	14.60	15.12
Distillate Fuel Oil 7/	13.58	17.52	19.79	19.49	18.02	17.11	16.76	16.03	16.34	16.22	15.79	15.91	16.22	16.15	16.36	16.91	16.81	17.08	17.65	17.29	17.90	18.50	18.41	18.77	19.61	19.54	20.27
Residual Fuel Oil	4.85	5.51	7.16	8.98	9.00	8.50	8.00	7.69	8.27	8.03	8.07	8.08	8.20	8.49	8.54	8.76	8.97	9.24	9.46	9.70	10.00	10.39	10.76	11.00	11.25	11.65	11.96
Natural Gas 8/	11.93	13.75	10.98	11.08	10.94	11.18	13.11	12.77	13.10	12.81	12.78	12.70	12.81	12.94	12.92	13.02	13.02	13.10	13.36	13.49	13.62	13.84	13.96	14.14	14.31	14.45	14.75
Electricity	26.14	25.22	26.16	25.77	25.74	25.39	25.00	24.67	24.90	25.73	25.47	25.45	25.58	26.01	26.40	26.51	26.64	26.78	27.13	27.40	27.45	27.56	27.81	27.73	27.85	28.35	28.79
Electric Power 9/																											
Distillate Fuel Oil	9.57	11.41	13.24	14.23	13.59	12.54	11.68	10.83	10.87	10.14	10.11	10.17	10.30	10.56	10.76	11.17	11.27	11.55	11.84	12.02	12.33	12.61	12.89	13.21	13.51	13.86	14.16
Residual Fuel Oil	5.05	7.05	7.85	7.28	7.32	6.92	6.53	6.16	9.13	7.98	8.62	9.00	9.35	9.72	10.10	10.78	11.12	11.61	11.86	12.26	12.77	13.25	13.80	14.18	14.79	15.46	15.68
Natural Gas	6.11	8.17	6.97	7.05	7.04	6.59	6.37	6.09	6.40	6.14	6.17	6.11	6.23	6.42	6.40	6.47	6.54	6.64	6.85	7.01	7.10	7.29	7.46	7.55	7.67	7.85	8.15
Steam Coal	1.40	1.53	1.68	1.70	1.69	1.68	1.66	1.62	2.86	2.89	2.93	2.98	3.09	3.20	3.32	3.45	3.59	3.75	3.93	4.11	4.31	4.52	4.74	4.99	5.27	5.54	5.85
Biomass (remove for AEO tables)	1.51	1.84	1.60	1.71	2.17	2.28	2.43	2.31	2.30	2.22	2.16	2.09	2.03	2.03	2.06	2.06	2.11	2.17	2.26	2.31	2.47	2.54	2.79	2.94	3.05	3.07	3.03
Average Price to All Users 10/																											
Liquefied Petroleum Gases	12.69	17.48	19.46	18.93	18.87	18.36	18.15	17.79	17.80	17.59	17.60	17.54	17.68	17.85	17.87	17.94	17.95	18.02	18.20	18.34	18.44	18.59	18.72	18.81	18.86	18.95	19.15
E85 4/	20.91	23.10	24.81	28.94	27.18	25.60	24.80	23.86	23.23	22.39	22.01	21.08	21.23	20.81	20.94	21.14	21.00	21.05	21.50	21.52	21.74	21.87	21.96	22.14	22.40	22.60	23.08
Motor Gasoline 5/	15.71	18.60	21.11	21.42	19.74	18.51	18.03	17.28	17.71	17.60	16.90	17.04	17.26	17.07	17.43	18.06	17.71	17.95	18.54	18.48	18.91	19.43	19.39	19.84	20.48	20.62	21.21
Jet Fuel	9.22	13.14	14.96	12.97	11.66	11.08	10.86	10.39	10.95	10.92	10.74	10.89	11.07	11.11	11.36	11.89	11.84	12.13	12.65	12.64	13.02	13.52	13.60	13.97	14.43	14.60	15.12
Distillate Fuel Oil	12.91	16.21	18.42	18.28	17.02	16.11	15.64	14.95	15.16	15.04	14.68	14.80	15.08	15.06	15.27	15.81	15.73	16.01	16.55	16.26	16.82	17.38	17.33	17.69	18.46	18.44	19.12
Residual Fuel Oil	5.13	6.64	7.92	8.36	8.39	7.95	7.52	7.15	8.41	7.92	8.10	8.18	8.31	8.59	8.69	8.96	9.17	9.44	9.65	9.84	10.14	10.45	10.80	11.04	11.28	11.60	11.90
Natural Gas	7.82	9.64	9.13	8.71	8.65	8.18	7.94	7.63	7.75	7.49	7.52	7.45	7.57	7.75	7.72	7.76	7.81	7.88	8.08	8.25	8.34	8.52	8.67	8.79	8.86	8.97	9.18
Metallurgical Coal	2.31	3.06	3.26	3.32	3.30	3.20	3.10	2.99	4.34	4.28	4.34	4.38	4.49	4.61	5.08	5.23	5.39	5.63	5.82	6.03	6.25	6.48	6.73	7.01	7.31	7.62	7.97
Other Coal	1.43	1.57	1.71	1.73	1.73	1.71	1.70	1.66	2.89	2.92	2.96	3.01	3.12	3.23	3.35	3.48	3.62	3.78	3.95	4.14	4.34	4.55	4.77	5.02	5.30	5.57	5.87
Coal to Liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	23.01	23.73	24.44	24.51	24.31	24.03	23.75	23.35	23.71	24.24	23.96	24.00	24.23	24.65	25.04	25.29	25.57	25.96	26.32	26.60	26.73	26.93	27.27	27.35	27.50	28.02	28.57
Non-Renewable Energy Expenditures by Sector (billion 2005 dollars)																											
Residential	195.99	215.13	219.10	221.84	223.25	220.95	220.83	219.11	221.06	222.32	222.18	223.21	226.70	230.45	233.11	235.46	237.70	239.97	243.79	246.77	249.44	252.16	256.23	258.95	261.92	265.83	271.16
Commercial	141.78	154.38	158.11	156.62	159.14	158.42	158.30	157.59	160.56	164.78	165.80	168.27	172.36	177.68	182.17	186.33	190.26	195.27	200.94	205.81	209.65	214.39	219.90	223.57	227.95	235.08	242.61
Industrial	184.23	196.07	205.54	218.29	214.04	208.89	202.37	195.24	201.68	199.43	198.54	198.60	201.51	205.40	207.83	211.60	214.71	218.94	224.36	228.12	232.73	238.22	243.27	248.31	252.50	258.00	265.58
Transportation	385.00	474.63	545.66	544.73	506.37	482.82	477.31	463.66	482.13	485.44	475.32	485.41	499.07	501.84	517.36	542.10	541.56	556.67	581.88	584.95	607.59	633.04	639.95	662.10	692.25	703.48	733.05
Total Non-Renewable Expenditures	907.00	1040.22	1128.41	1141.49	1102.80	1071.09	1058.81	1035.60	1065.43	1071.97	1061.85	1075.49	1099.64	1115.38	1140.47	1175.49	1184.22	1210.84	1250.98	1265.66	1299.40	1337.81	1359.35	1392.93	1434.61	1462.39	1512.39
Transportation Renewable Expenditures	0.02	0.03	0.05	0.04	0.04	0.05	0.05	0.05	0.07	0.07	0.08	0.09	0.11	0.11	0.12	0.16	0.17	0.21	0.29	0.30	0.38	0.46	0.50	0.59	0.71	0.77	0.86
Total Expenditures	907.02	1040.26	1128.46	1141.53	1102.84	1071.13	1058.86	1035.66	1065.49	1072.04	1061.93	1075.58	1099.75	1115.49	1140.59	1175.66	1184.39	1211.05	1251.27	1265.96	1299.78	1338.27	1359.86	1393.52	1435.32	1463.17	1513.25

HEARING EXHIBIT - 00000212

Attachment POD-1.o. AEO2007 Table 3 Reference Case, Energy Prices by Sector and Source

HEARING EXHIBIT - 00000213

Table 3. Energy Prices by Sector and Source
(2005 dollars per million Btu, unless otherwise noted)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2005-2030
Residential																												
Liquefied Petroleum Gases	18.21	19.29	21.16	24.54	24.49	23.96	23.67	23.26	23.11	22.91	22.94	22.88	22.98	23.19	23.13	23.09	23.18	23.15	23.29	23.42	23.54	23.53	23.56	23.65	23.78	23.87	23.91	0.9%
Distillate Fuel Oil	12.89	14.73	16.91	17.45	16.91	15.84	14.87	14.03	13.36	12.60	12.52	12.60	12.63	12.74	12.83	13.05	13.15	13.26	13.42	13.36	13.51	13.56	13.63	13.80	13.90	14.06	14.13	-0.2%
Natural Gas	10.72	12.43	13.04	11.83	11.74	11.25	10.98	10.59	10.44	10.25	10.29	10.24	10.33	10.56	10.49	10.44	10.54	10.54	10.67	10.83	10.95	10.97	11.02	11.12	11.26	11.37	11.43	-0.3%
Electricity	27.10	27.59	27.64	27.49	27.37	27.15	26.91	26.51	26.28	26.17	26.04	25.99	26.09	26.30	26.45	26.36	26.37	26.42	26.42	26.46	26.56	26.61	26.56	26.57	26.61	26.74	26.76	-0.1%
Commercial																												
Distillate Fuel Oil	10.48	12.68	14.63	15.32	14.44	13.45	12.72	11.98	11.34	10.85	10.67	10.73	10.87	10.93	11.02	11.29	11.35	11.46	11.69	11.51	11.68	11.85	11.86	12.05	12.25	12.33	12.45	-0.1%
Residual Fuel Oil	6.25	8.41	10.10	7.88	7.80	7.68	7.54	7.06	6.92	5.99	6.31	6.49	6.45	6.59	6.70	6.99	7.07	7.24	7.40	7.24	7.38	7.17	7.30	7.40	7.46	7.24	7.31	-0.6%
Natural Gas	9.40	11.20	11.38	10.27	10.16	9.63	9.34	8.92	8.75	8.54	8.55	8.48	8.55	8.74	8.66	8.60	8.67	8.64	8.75	8.87	8.97	8.96	8.98	9.05	9.17	9.25	9.30	-0.7%
Electricity	24.59	25.25	25.74	25.34	25.27	24.92	24.50	23.86	23.59	23.44	23.31	23.33	23.48	23.75	23.94	23.89	23.95	24.00	24.01	24.08	24.20	24.23	24.18	24.16	24.21	24.29	24.27	-0.2%
Industrial 1/																												
Liquefied Petroleum Gases	17.18	16.96	16.96	17.51	17.39	16.75	16.42	15.94	15.77	15.62	15.63	15.57	15.68	15.87	15.87	15.86	15.91	15.88	15.99	16.11	16.25	16.22	16.23	16.32	16.42	16.51	16.55	-0.1%
Distillate Fuel Oil	10.99	13.08	15.14	15.44	14.29	13.42	12.95	12.48	11.88	11.64	11.35	11.40	11.63	11.63	11.74	12.06	12.04	12.14	12.42	12.17	12.36	12.62	12.58	12.79	13.07	13.06	13.25	0.1%
Residual Fuel Oil	5.77	7.77	9.34	9.88	10.08	9.79	9.50	8.78	8.47	8.04	7.98	8.21	8.41	8.56	8.61	8.81	8.91	9.07	9.21	9.15	9.29	9.26	9.38	9.50	9.50	9.61	9.58	0.8%
Natural Gas 2/	6.47	8.16	7.45	7.36	7.29	6.74	6.43	6.02	5.87	5.68	5.69	5.65	5.74	5.92	5.88	5.84	5.90	5.89	6.00	6.12	6.24	6.21	6.25	6.33	6.43	6.51	6.56	-0.9%
Metallurgical Coal	2.31	3.06	3.25	3.30	3.29	3.19	3.09	2.99	2.89	2.79	2.74	2.72	2.71	2.71	2.70	2.69	2.71	2.72	2.72	2.71	2.69	2.70	2.70	2.72	2.73	2.74	2.75	-0.4%
Other Industrial Coal	1.80	2.15	2.20	2.24	2.25	2.24	2.26	2.25	2.23	2.21	2.21	2.20	2.19	2.19	2.18	2.18	2.18	2.20	2.21	2.21	2.22	2.23	2.24	2.25	2.27	2.27	2.29	0.2%
Coal to Liquids	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.89	0.88	0.88	0.89	0.89	0.89	0.90	0.91	0.95	0.97	1.01	1.03	1.03	1.12	1.23	1.27	1.28	1.33	1.33	1.33	N/A
Electricity	15.88	16.69	18.26	18.77	18.85	18.52	18.01	17.25	16.79	16.59	16.47	16.46	16.61	16.85	17.02	17.00	17.07	17.13	17.14	17.21	17.33	17.35	17.31	17.30	17.33	17.43	17.43	0.2%
Transportation																												
Liquefied Petroleum Gases 3/	19.68	23.92	26.81	22.71	22.76	22.27	24.34	23.93	23.76	23.54	23.56	23.49	23.56	23.75	23.65	23.58	23.66	23.63	23.74	23.87	23.97	23.95	23.98	24.06	24.17	24.26	24.29	0.1%
E85 4/	20.91	23.10	24.81	27.77	26.00	24.27	21.29	20.53	20.34	20.20	20.01	20.09	20.20	20.43	20.41	20.62	20.61	20.62	21.07	20.97	20.96	21.26	21.10	21.32	21.44	21.40	21.50	-0.3%
Motor Gasoline 5/	15.72	18.64	21.15	20.96	19.72	18.69	17.90	17.23	16.86	16.57	16.09	16.06	16.11	16.24	16.32	16.67	16.63	16.75	17.05	16.92	17.10	17.32	17.14	17.29	17.53	17.53	17.76	-0.2%
Jet Fuel 6/	9.22	13.14	14.96	12.99	11.72	11.26	10.91	10.37	10.06	10.03	9.84	9.89	10.03	10.09	10.21	10.52	10.51	10.59	10.89	10.79	10.91	11.10	11.05	11.23	11.52	11.51	11.75	-0.4%
Distillate Fuel Oil 7/	13.58	17.52	19.79	19.71	18.21	17.31	16.81	16.00	15.39	15.21	14.82	14.86	15.12	15.08	15.16	15.48	15.42	15.49	15.77	15.47	15.64	15.91	15.83	16.03	16.33	16.26	16.47	-0.2%
Residual Fuel Oil	4.85	5.51	7.16	6.82	9.05	8.60	8.05	7.69	7.34	7.10	6.97	7.04	7.03	7.12	7.14	7.17	7.36	7.49	7.65	7.68	7.85	7.90	8.04	8.18	8.12	8.38	8.27	1.6%
Natural Gas 8/	11.91	14.76	11.98	12.28	12.14	12.32	13.97	13.51	13.29	13.04	12.94	12.86	12.89	13.03	12.95	12.98	12.95	13.08	13.11	13.20	13.22	13.18	13.24	13.36	13.40	13.45	-0.4%
Electricity	26.10	25.22	26.12	25.63	25.75	25.39	24.86	24.32	24.13	23.98	23.79	23.81	23.88	24.07	24.26	24.18	24.22	24.25	24.22	24.31	24.43	24.47	24.39	24.35	24.40	24.48	24.46	-0.1%
Electric Power 9/																												
Distillate Fuel Oil	9.52	11.38	13.24	14.26	13.77	12.70	11.71	10.78	10.03	9.29	9.20	9.26	9.28	9.44	9.54	9.75	9.84	9.96	10.11	10.08	10.22	10.25	10.32	10.49	10.57	10.74	10.79	-0.2%
Residual Fuel Oil	4.99	6.96	7.85	7.19	7.29	6.99	6.58	6.21	5.90	5.46	5.45	5.60	5.63	5.74	5.81	6.01	6.08	6.23	6.42	6.32	6.53	6.58	6.64	6.73	6.75	6.85	6.85	-0.1%
Natural Gas	6.11	8.16	6.97	7.12	7.07	6.53	6.22	5.83	5.69	5.50	5.54	5.50	5.60	5.79	5.72	5.67	5.76	5.73	5.84	5.95	6.06	6.05	6.07	6.15	6.25	6.31	6.33	-1.0%
Steam Coal	1.40	1.53	1.67	1.69	1.70	1.70	1.71	1.67	1.64	1.62	1.61	1.60	1.59	1.59	1.58	1.58	1.58	1.59	1.60	1.60	1.61	1.63	1.64	1.65	1.67	1.67	1.69	0.4%
Average Price to All Users 10/																												
Liquefied Petroleum Gases	12.69	17.48	19.46	19.00	18.88	18.29	18.02	17.57	17.42	17.27	17.29	17.24	17.36	17.56	17.56	17.56	17.62	17.60	17.72	17.84	17.99	17.96	17.99	18.08	18.18	18.26	18.30	0.2%
E85 4/	20.91	23.10	24.81	27.77	26.00	24.27	21.29	20.53	20.34	20.20	20.01	20.09	20.20	20.43	20.41	20.62	20.61	20.62	21.07	20.97	20.96	21.26	21.10	21.32	21.44	21.40	21.50	-0.3%
Motor Gasoline 5/	15.71	18.60	21.11	20.96	19.72	18.69	17.90	17.23	16.86	16.56	16.08	16.06	16.11	16.24	16.32	16.67	16.63	16.75	17.05	16.92	17.10	17.32	17.14	17.29	17.53	17.53	17.75	-0.2%
Jet Fuel	9.22	13.14	14.96	12.99	11.72	11.26	10.91	10.37	10.06	10.03	9.84	9.89	10.03	10.09	10.21	10.52	10.51	10.59	10.89	10.79	10.91	11.10	11.05	11.23	11.52	11.51	11.75	-0.4%
Distillate Fuel Oil	12.91	16.22	18.42	18.44	17.20	16.30	15.70	14.92	14.36	14.18	13.86	13.92	14.15	14.14	14.24	14.56	14.53	14.62	14.90	14.65	14.83	15.08	15.03	15.24	15.53	15.50	15.70	-0.1%
Residual Fuel Oil	5.10	6.59	7.92	8.25	8.41	8.06	7.61	7.19	6.87	6.45	6.41	6.55	6.57	6.68	6.74	6.87	7.00	7.14	7.31	7.27	7.45	7.47	7.58	7.70	7.68	7.83	7.79	0.7%
Natural Gas	7.83	9.65	9.14	8.76	8.66	8.13	7.83	7.44	7.29	7.09	7.12	7.06	7.15	7.35	7.29	7.24	7.32	7.31	7.44	7.57	7.69	7.68	7.73	7.82	7.94	8.03	8.09	-0.7%
Metallurgical Coal	2.31	3.06	3.25	3.30	3.29	3.19	3.09	2.99	2.89	2.79	2.74	2.72	2.71	2.71	2.70	2.69	2.71	2.72	2.72	2.71	2.69	2.70	2.70	2.72	2.73	2.74	2.75	-0.4%
Other Coal	1.43	1.57	1.71	1.73	1.74	1.73	1.74	1.70	1.67	1.66	1.65	1.63	1.63	1.62	1.61	1.61	1.61	1.62	1.63	1.63	1.65	1.66	1.67	1.68	1.69	1.70	1.72	0.4%
Coal to Liquids	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.89	0.88	0.88	0.89	0.89	0.89	0.90	0.91	0.95	0.97	1.01	1.03	1.03	1.12	1.23	1.27	1.28	1.33	1.33	1.33	N/A
Electricity	23.01	23.73	24.38	24.32	24.30	24.02	23.66	23.09	22.80	22.66	22.55	22.55	22.69	22.95	23.14	23.09	23.15	23.21	23.23	23.30	23.43	23.47	23.43	23.43	23.48	23.59	23.60	0.0%
Non-Renewable Energy Expenditures by Sector (billion 2005 dollars)																												
Residential	195.99	215.13	218.81	221.30	223.50	221.10	220.44	218.08	218.46	217.85	219.40	221.00	224.59	228.53	230.97	232.57	236.03	237.58	240.44	243.39	247.24	248.99	251.03	253.73	257.29	259.96	262.21	0.8%
Commercial	141.78	154.38	157.85	156.07	159.31	158.54	157.97	156.35	157.31	158.59	160.74	163.37	167.21	172.04	175.58	178.09	181.74	185.01	188.79	192.87	197.36	201.11	204.49	208.50	213.25	217.97	222.08	1.5%
Industrial	184.23	196.07	205.40	217.88	214.15	207.11	200.48	191.81	187.29	184.92	184.25	184.11	186.81	189.66	190.50	192.03	194.88	196.87	200.07	202.13	205.49	206.98	209.31	212.90	216.30	219.27	222.08	0.5%
Transportation	385.00	474.66	545.72	538.79	508.11	488.45	476.38	463.41	458.16	458.57	452.79	459.42	469.74	478.67	487.87	505.29	511.07	521.65	538.78	540.64	554.21	570.28	574.30	588.98	607.12	615.46	632.79	1.2%
Total Non-Renewable Expenditures	907.00	1040.25	1127.78	1134.03	1105.07	1075.20	1055.27	1029.66	1021.22	1019.93	1017.18	1027.91	1048.35	1068.91	1084.92	1107.99	1123.73	1141.11	1168.07	1179.04	1204.30	1227.35	1239.13	1264.11	1293.96	1312.66	1339.16	1.0%
Transportation Renewable Expenditures	0.02	0.03	0.05	0.04	0.05	0.05	0.06	0.07	0.08	0.08	0.08	0.09	0.10	0.10	0.11	0.13	0.15	0.19	0.22	0.24	0.29	0.32	0.35	0.39	0.44	0.47	0.51	11.5%
Total Expenditures	907.02	1040.29	1127.82	1134.07	1105.12	1075.25	1055.33	1029.74	1021.30	1020.01	1017.26	1028.00	1048.45	1069.01	1085.04	1108.12	1123.89	1141.30	1168.29	1179.28	1204.59	1227.67	1239.48	1264.49	1294.40	1313.13	1339.68	1.0%

1/ Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
2/ Excludes use for lease and plant fuel.
3/ Includes Federal and State taxes while excluding county and local taxes.
4/ E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
5/ Sales weighted-average price for all grades. Includes Federal, State, and local taxes.
6/ Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
7/ Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
8/ Compressed natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
9/ Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
10/ Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
N/A = Not applicable.
Note: Data for 2004 and 2005 are model results and may differ slightly from official EIA data reports.
Sources: 2004 and 2005 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the Energy Information Administration (EIA), Petroleum Marketing Annual 2005, DOE/EIA-0487(2005) (Washington, DC, August 2006). 2004 residential and commercial natural gas delivered prices: EIA, Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005). 2005 residential and commercial natural gas delivered prices: EIA, Natural Gas Monthly, DOE/EIA-0130(2006/04) (Washington, DC, April 2006). 2004 and 2005 industrial natural gas delivered prices are estimated based on: EIA, Manufacturing Energy Consumption Survey 1994 and industrial and wellhead prices from the Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005) and the Natural Gas Monthly, DOE/EIA-0130(2006/04) (Washington, DC, April 2006). 2004 transportation sector natural gas delivered prices are based on: EIA, Natural Gas Annual 2004, DOE/EIA-0131(2004) (Washington, DC, December 2005) and estimated state taxes, federal taxes, and dispensing costs or charges. 2005 transportation sector natural gas delivered prices are model results. 2004 and 2005 electric power sector natural gas prices: EIA, *Electric Power Monthly*, May 2005 through April 2006, Table 4.11.A. 2004 and 2005 coal prices based on: EIA, Quarterly Coal Report, October-December 2005, DOE/EIA-0121 (2005/4Q) (Washington, DC, March 2006) and EIA, AEO2007 National Energy Modeling System run aeo2007.d112106a. 2004 and 2005 electricity prices: EIA, Annual Energy Review 2005, DOE/EIA-0384(2005) (Washington, DC, July 2006). 2004 and 2005 ethanol prices derived from weekly spot prices in the Oxy Fuel News. Projections: EIA, AEO2007 National Energy Modeling System run aeo2007.d112106a.

HEARING EXHIBIT - 00000214

Attachment POD-2.1. EPA Analysis of the Lieberman-Warner Climate Security Act of 2008: S.2191 in 110th Congress. March 14, 2008.



U.S. Environmental Protection Agency
Office of Atmospheric Programs

EPA Analysis of the Lieberman-Warner Climate Security Act of 2008

S. 2191 in 110th Congress

March 14, 2008

FMPA-POD:-00054

HEARING EXHIBIT - 00000216

Request for EPA Analysis

United States Senate
WASHINGTON, DC 20510

November 9, 2007

The Honorable Stephen L. Johnson
Administrator
Environmental Protection Agency
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Dear Administrator Johnson:

We are writing to request that EPA estimate the economic, greenhouse-gas emissions, and atmospheric greenhouse-gas concentration impacts of S.2191, America's Climate Security Act of 2007. A similar request is being sent to the Energy *Information Administration.*

We ask that EPA begin this process by meeting with our staff as soon as possible to discuss the parameters, methods, and duration of the analysis. Please call David McIntosh in Senator Lieberman's office at (202) 224-5016 or Chelsea Maxwell in Senator Warner's office at (202) 224-6283.

Thank you for your assistance with this analysis.

Sincerely,

Joseph I. Lieberman
UNITED STATES SENATOR

John Warner
UNITED STATES SENATOR

- On November 9, 2007 Senators Lieberman and Warner requested that EPA estimate the economic impacts of the S. 2191, the 'Climate Security Act of 2007' (now the 'Lieberman-Warner Climate Security Act of 2008').
- This document constitutes EPA's analysis in response to this request. The analysis is available online at:

www.epa.gov/climatechange/economics/economicanalyses.html

- The analysis was conducted by EPA's Office of Atmospheric Programs.
  Contact: Francisco de la Chesnaye.
  Tel: 202-343-9010.
  Email: delachesnaye.francisco@epa.gov.

FMPA-POD1-00055

HEARING EXHIBIT - 00000217

Key Results & Insights

S. 2191 places declining GHG emission caps upstream on petroleum, natural gas, as well as manufacturers of F-gases and N_2O and downstream on coal facilities. The bill establishes a market-driven system of tradable emission allowances and permits the use of domestic offsets and international credits. There also are bonus allowances for carbon capture and storage and set-asides for agriculture & forestry sequestration and landfill and coal mine methane mitigation.

There are many uncertainties that affect the economic impacts of S. 2191, key among them are the availability of mitigation technologies and the level of international action on climate change. EPA analyzed ten different scenarios to evaluate a range of assumptions and key parameters. This analysis does not necessarily reflect EPA's views on what is most likely to occur.

Emissions Impacts

- Under S. 2191 total U.S. GHG emissions are approximately 40% lower (~ 3,749 $MtCO_2e$) than reference case emissions in 2030 (~11% below 1990 levels) and 56% lower (~ 6,030 $MtCO_2e$) in 2050 (~25% below 1990 levels).
- S.2191 covers 82% of total U.S. GHG emissions in both 2030 and 2050.
- While the impacts of S. 2191 on global CO_2 concentrations are not explicitly analyzed here, based on EPA's previous analysis of the Lieberman-McCain bill (S. 280) and the fact that S. 2191 requires greater emissions reductions than that bill, the incremental impact of S. 2191 on global CO_2 concentrations would likely be greater than 25 ppm in 2095. Assuming Kyoto countries (excluding Russia) reduce emissions to 50% below 1990 levels by 2050, and all other countries adopt GHG emissions targets in 2025 and return emissions to 2000 levels by 2035, the global CO_2 concentration in 2095, while not stabilized, would likely be lower than 491 ppm if the US adopts S. 2191.
  - EPA plans to release the revised version of this analysis in early June, 2008 that will incorporate the Energy Independence and Security Act into the baseline. This revised analysis will also include an explicit analysis of global CO_2 concentrations.

Sector Impacts

- The greatest emission abatement under S. 2191 occurs in CO_2 emissions from the electricity sector.
- The transportation sector provides a relatively small proportion of CO_2 emissions abatement. This result reflects relatively modest indirect price signal an upstream cap and trade program sends to the transportation sector.
  - The price signal provided by S. 2191 (~$0.53 increase in the price of gasoline in 2030, ~$1.40 increase in 2050), is not high enough to cause large changes in the demand for transportation or changes in how transportation services are provided.
  - This analysis did not estimate the reductions that could be achieved under a direct fuel and vehicle regulatory framework.

FMPA-POD1-00056
HEARING EXHIBIT - 00000218

Key Results & Insights (con't)

Economic Impacts

- In the S.2191 Scenario, modeled allowance prices range between \$61 - 83/tCO_2e in 2030, and \$159 - 220/tCO_2e in 2050. Under an alternative reference scenario with lower emissions in the baseline, modeled allowance prices range between \$46 - 73/tCO_2e in 2030, and \$121 - 193/tCO_2e in 2050.
- From the various scenarios analyzed, the use or limitation of offsets and international credits has a larger impact on allowance prices than the modeled availability or constraint of key enabling technologies.
- By 2030, GDP and consumption are projected to increase 97% from 2007 levels in the Reference Scenario. By 2050, the projected increase in GDP and consumption from 2007 levels is 215%.
- Under S.2191, GDP is modeled to be between 0.9% (\$238 billion) and 3.8% (\$983 billion) lower in 2030 and between 2.4% (\$1,012 billion) and 6.9% (\$2,856 billion) lower in 2050 than in the Reference Scenario. Consumption is modeled to be between 0.9% (\$180 billion) and 1.4% (\$233 billion) lower in 2030 and between 2.1% (\$670 billion) and 3.3% (\$843 billion) lower in 2050 than in the Reference Scenario.
- The average annual growth rate of consumption is ~0.08 percentage points lower than the reference case. In 2030 per household average annual consumption is ~\$1,375 lower and gasoline prices increase ~\$0.53 per gallon. In 2050 per household average annual consumption is ~\$4,377 lower and gasoline prices increase ~\$1.40 per gallon.
- Electricity prices are projected to increase 44% in 2030 and 26% in 2050, assuming the cost of allowances can partially be passed on to consumers (as is the case in a full auction). If allowances are given directly to power companies, the cost of those allowances would not be passed on to consumers in regulated electricity markets, so electricity price increases would be smaller in much of the country.
- In our modeling, market outcomes are invariant to the auctioning of allowances given the assumption of lump sum transfers of auction revenues back to households. If the auction revenues were instead used to lower distortionary taxes, the costs of the policy would be lower. Other uses of auction revenues have the potential to increase the costs of the policy.
- The economic benefits of reducing emissions were not determined for this analysis.

FMPA-POD1-00057

HEARING EXHIBIT - 00000219

Key Results & Insights (con't)

Enabling Technologies

- Different assumptions in the economy-wide model and the detailed energy sector model demonstrate the importance of key enabling technologies, specifically Carbon Capture and Storage (CCS) and nuclear power.
  - While not yet proven on a commercial scale, CCS has been the focus of considerable R&D funding. The combination of allowance price and subsidy for CCS causes the technology to deploy before 2020. Detailed electricity sector modeling shows CCS penetration by 2015.
- Detailed electricity sector modeling suggests many existing coal plants are no longer economic to run and operate. Economy-wide models indicate that fossil fuel usage peaks in 2010 with a slow decline to 2050.
- The rate of CCS penetration is subject to a great deal of uncertainty. Given our assumptions about availability, cost, and performance of CCS technology, economy-wide modeling shows a small amount of CCS built in 2020 with the rate increasing until most all traditional fossil is displaced by 2040. Detailed electricity sector modeling suggests that the initial penetration of CCS may be much faster.
- In economy-wide modeling, other non-fossil generation (e.g. biomass, wind and solar) plays a significant role under S. 2191.
- In the core scenarios, nuclear power grows by ~150% by 2050 from 2005 levels. In scenarios where technologies were constrained, i.e., nuclear power growth limited to ~ 75%, delay of CCS deployment until 2030 or limited use of biomass for electricity generation, costs were significantly higher: GHG allowances prices increased more than 80% in 2030 and 2050 and GDP losses increased by more than 150% in 2030 and 80% in 2050.

EMPA-POD1-00058

HEARING EXHIBIT - 00000220

Key Results & Insights (con't)

Regional Impacts

- Regional impacts depend on a variety of factors, including economic base, energy use, electricity generation, and allowance allocation.
- Across all regions, the most significant emissions reductions are from coal use, with the largest reductions coming in the South and Midwest regions. By 2030, electricity generation is switching from coal to natural gas and CCS.
- In the majority of regions, GDP and consumption impacts are less than 3% in 2030 and 2050. The largest GDP and consumption impacts are in the Plains region. (This is driven by among other things, regional differences in the energy and manufacturing industry composition; regional energy use patterns including household heating and cooling needs, and average distance traveled; and existing fossil fuel capacity in the electricity sector).

Emissions Leakage and International Climate Policy Sensitivity

- Under the core S. 2191 international assumptions, no international emissions leakage occurs. In fact, emissions in Group 2 countries fall by over 12,000 million metric tons CO_2 equivalent ($MtCO_2e$) as they adopt emission targets beginning in 2025.
- As Group 2 countries adopt targets, the U.S. imports fewer energy-intensive manufacturing goods from Group 2, and exports more.
- Under Alternative International Action assumptions, Group 2 countries do not take any action. Emissions leakage occurs under these assumptions, with Group 2 emissions rising by 350 $MtCO_2e$ in 2030, and 385 $MtCO_2e$ in 2050 from the reference case. This is a less than 1% increase in Group 2 emissions from the reference levels, and is equivalent to U.S. emissions leakage rates of approximately 11% in 2030 and 8% in 2050.The amount of leakage is somewhat limited by the purchase of international offsets from Group 1 Countries to meet the U.S. cap.
- It is assumed that the International Reserve Allowance Requirement is triggered in the Alternative International Action scenario, which limits the emissions leakage marginally. Without this import requirement, emissions leakage is 361 $MtCO_2e$ in 2030, and 412 $MtCO_2e$ in 2050, which is equivalent to the same leakage rates as with the international allowance requirement.
- Under Alternative International Action, the U.S. exports less energy-intensive manufacturing goods to Group 2, as Group 2 countries use more of their domestic energy-intensive manufacturing, resulting in increased emissions in Group 2. Imports of energy-intensive manufacturing goods from Group 2 to the U.S. rise in 2030 since Group 2 is not taking any emission action. In the absence of the International Reserve Allowance Requirement, imports from Group 2 would increase to a greater extent.

FMPA-POD1-00059

HEARING EXHIBIT - 00000221

Key Results & Insights (con't)

Offsets Sensitivities

- If the use of domestic offsets and international credits is unlimited, then allowance prices fall by 71% compared to the bill as written.
  - In this scenario 52% of abatement comes from international credits in 2030, and 45% of abatement comes from international credits in 2050. In terms of compliance obligation (which is limited to 15% for international credits in the bill as written) 65% comes from international credits in 2030, and 169% comes from international credits in 2050.
- If the use of domestic offsets is unlimited, and international credits are still limited to 15% of compliance obligation, then allowance prices fall by 26% compared to the bill as written.
  - In this scenario 26% of abatement comes from domestic offsets in 2030 and 15% of abatement comes from domestic offsets in 2050. In terms of compliance obligation (which is limited to 15% for domestic offsets in the bill as written) 33% comes from domestic offsets in 2030, and 41% comes from domestic offsets in 2050.
- If international credits are not allowed (or are more expensive than U.S. GHG allowances), and domestic offsets are still limited to 15%, then allowance prices increase by 34% compared to the bill as written.
- If domestic offsets and international credits are not allowed, and the caps must be met solely through emissions reductions in covered sectors, then allowance price increases by 93% compared to the bill as written.

Alternative Reference Sensitivities and the Energy Independence and Security Act of 2007

- This analysis of S. 2191 was initiated before the signing of the Energy Independence and Security Act (EISA) of 2007. The Act is not included in EPA Reference Scenario which is based on EIA's AEO 2006 Reference case.
- Since AEO 2006 there have been important updates to EIA's most current reference case in the AEO 2008 that are relevant to the analysis of S. 2191, particularly in projected energy consumption and CO_2 emissions.
- EISA is also expected to have implications for the U.S. Reference Case emissions of greenhouse gases.
- EPA analyzes an Alternative Reference Scenario and the effects of S. 2191 on that reference case. The Alternative Reference Scenario assumes earlier adoption of energy efficient and low emitting technology. In this sense, they are qualitatively similar to a reference case reflecting the Energy Security and Independence Act of 2007. EPA has not yet modeled the Energy Act. We expect the difference between the economic impacts in the Reference analysis and the Alternative Reference Scenario analysis to be directionally similar to forthcoming runs incorporating the AEO 2008 assumptions which will include the incentives and standards of the Energy Act.
- Under Alternative Reference Scenario assumptions, in 2030 the reference case emissions are ~7% (~650 $MtCO_2e$) lower than under the core technology assumptions.
- Under S. 2191 Alternative Scenario, total U.S. GHG emissions are approximately 35% (~3,100 $MtCO_2e$) lower than the Alternative Reference Scenario emissions in 2030, and 52% (~5,200 $MtCO_2e$) lower in 2050.

FMPA-POD1-00060

HEARING EXHIBIT - 00000222

Key Uncertainties

- There are many uncertainties that affect the economic impacts of S. 2191.
- This analysis contains a set of scenarios that cover some of the most important uncertainties:
  - The extent and stringency of international actions to reduce GHG emissions by developed and developing countries.
  - The availability of foreign credits and international offset projects.
  - The availability of domestic offset projects.
  - The degree to which new nuclear power is technically, politically, and socially feasible.
  - Whether or not carbon capture and storage technology will be available at a large scale.

FMPA-POD1-00061
HEARING EXHIBIT - 00000223

Contents

- Legislative Assessment and Analytical Approach
- GHG Emissions Results
- Detailed Near-Term Electricity Sector Modeling Results
- Energy Sector Modeling Results
- Economy-Wide and Sectoral Modeling Results
- Regional Modeling Results
- Global Results: Emissions Leakage and Alternative International Action Sensitivities
- Offsets and International Credits
- Additional Qualitative Considerations
- Appendix 1: Modeling Approach and Limitations
- Appendix 2: Scenario Comparison Tables
- Appendix 3: Comparison to EPA's Analyses of S. 280 and S. 1766
- Appendix 4: Additional Information
- Appendix 5: Request Letters
- Appendix 6: Model Descriptions

FMPA-POD1-00062

HEARING EXHIBIT - 00000224

Legislative Assessment and Analytical Approach

FMPA-POD1-00063

HEARING EXHIBIT - 00000225

"Lieberman-Warner Climate Security Act of 2008" (S. 2191) Bill Summary

- Economy-wide coverage:
  - Upstream on petroleum, natural gas, as well as manufacturers of F-gases and N_2O
  - Downstream on coal facilities (that use over 5,000 tons of coal per year)
- GHG emission targets for covered sectors (targets decline in each calendar year):

  2012: 5,775 $MtCO_2e$
  2020: 4,924 $MtCO_2e$
  2030: 3,860 $MtCO_2e$
  2050: 1,732 $MtCO_2e$ (70% below 2005 emissions levels from covered facilities)

- Establishes a market-driven system of tradable emission allowances
- Establishes a separate cap and trade system for the consumption of HFCs
  - EPA's mitigation estimates for HFCs are based on production of the chemicals; the bill calls for reductions in HFC consumption. EPA is currently revising its mitigation estimates to more appropriately analyze this provision of the bill and will provide the analysis in the revised version of the full analysis in early June.
- Domestic offsets may be used to meet 15% of compliance obligation
- International credits may be used to meet 15% of compliance obligation
- Establishes a Carbon Market Efficiency Board
- Set-asides for agriculture and forestry sequestration as well as landfill and coal mine methane
- Bonus allowances for CCS*
- International reserve allowance requirement*

* The bonus allowances for CCS, and the international reserve allowance requirement provisions are similar to provisions in the Bingaman Specter bill (S. 1766). EPA's analysis of S. 1766 is available at:www.epa.gov/climatechange/economics/economicanalyses.html

Note: Additional Provisions of the bill that are not modeled are discussed in Appendix 1: Modeling Approach and Limitations

FMPA-POD1-00064
HEARING EXHIBIT - 00000226

Analytical Scenarios

The assumptions about other domestic and international policies that affect the results of this analysis do not necessarily reflect EPA's views on what is most likely to occur.

1) EPA Reference Scenario

- This reference scenario is identical to the reference scenario used in the EPA analyses of S. 280 and S. 1766
  - Does not include any additional climate policies or measures to reduce international GHG emissions
  - For domestic projections, benchmarked to AEO 2006 (which does not include the Energy Independence and Security Act).
  - For international projections, uses CCSP Synthesis and Assessment Report 2.1 A MiniCAM Reference

2) S. 2191 Scenario

- This policy scenario uses the same assumptions about technology and international action used in the *main policy scenarios* in the EPA analyses of S. 280 and S. 1766
  - Bill as written
  - Substantial growth in nuclear power (nuclear power generation increases by ≈150% from 782 bill. kWh in 2005 to 1,982 bill. kWh in 2050) reflecting possible future policies to promote this technology in S. 2191 and elsewhere
  - Widespread international actions by developed and developing countries over the modeled time period. International policy assumptions are based on those used in the recent MIT report, "Assessment of U.S. Cap-and-Trade Proposals"
    - Group 1 countries (Kyoto group less Russia) follow an allowance path that is falling gradually from the simulated Kyoto emissions levels in 2012 to 50% below 1990 in 2050
    - Group 2 countries (rest of world) adopt a policy beginning in 2025 that returns and holds them at year 2015 emissions levels through 2034, and then returns and maintains them at 2000 emissions levels from 2035 to 2050

FMPA-POD1-00065

HEARING EXHIBIT - 00000227

Analytical Scenarios (con't)

In the following scenarios all assumptions are identical to scenario 2 unless specified. These scenarios are drawn from the EPA analysis of S. 280.

3) S. 2191 Scenario with Low International Actions

- This policy scenario uses the same assumptions used in the "low international action" policy scenarios from EPA's analyses of S. 280 and S. 1766
  - Group 2 (developing) countries do not take on GHG emissions targets over the period of the analysis
  - Group 1 countries continue on a "Kyoto Forever" path

4) S. 2191 Scenario Allowing Unlimited Offsets

- This policy scenario uses the same assumptions used in the "Unlimited Offsets" policy scenarios from EPA's analyses of S. 280 and S. 1766
  - Removes the constraint in S. 2191 that limits the usage of domestic offsets to 15% of allowance submissions
  - Removes the constraint in S. 2191 that limits the usage of international credits to 15% of allowance submissions

5) S. 2191 Scenario with No Offsets

- This policy scenario uses the same assumptions used in the "No Offsets" policy scenarios from EPA's analysis of S. 280
  - Assumes offsets and international credits are not allowed so that all reductions must come from covered entities within covered sectors

FMPA-POD1-00066

HEARING EXHIBIT - 00000228

Analytical Scenarios (con't)

In the following scenarios *all assumptions* are identical to scenario 2 unless specified. These scenarios are based on the scenarios requested by Senators Inhofe, Voinovich, and Barrasso.

6) S. 2191 Constrained Nuclear & Biomass

- Assumes nuclear power does not exceed reference case growth
- Assumes biomass power does not exceed reference case growth

7) S. 2191 Constrained Nuclear, Biomass, and CCS

- Assumes nuclear power does not exceed reference case growth
- Assumes biomass power does not exceed reference case growth
- Assumes carbon capture and sequestration technology does not become commercially available until 2030

8) S. 2191 Constrained Nuclear, Biomass, and CCS + *Beyond Kyoto* + Natural Gas Cartel

- Assumes nuclear power does not exceed reference case growth
- Assumes biomass power does not exceed reference case growth
- Assumes carbon capture and sequestration technology does not become commercially available until 2030
- Assumes GHG caps in Group 1 countries are implemented and reduced to 20% below 1990 levels in 2020 and on a trajectory to 80% below 1990 levels in 2050
- Assumes Group 2 countries adopt a policy beginning in 2025 that returns and holds them at year 2015 emissions levels through 2034, and then returns and maintains them at 2000 emissions levels from 2035 to 2050
- Assumes a functioning natural gas cartel that can extract natural gas prices equivalent to the energy content parity with Low Sulfur Light imported crude

FMPA-POD1-00067

HEARING EXHIBIT - 00000229

Analytical Scenarios (con't)

The following scenarios are based on the Alternative Reference scenarios from EPA's analysis of the Low Carbon Economy Act of 2007 (S. 2191).

9) Alternative Reference Scenario

- This reference scenario is identical to the 'High Technology Reference Scenario' used in the EPA analysis of S. 1766
  - Does not include any additional climate policies or measures to reduce international GHG emissions
  - For domestic projections, benchmarked to AEO 2006 High Technology Case
  - For international projections, use CCSP Synthesis and Assessment Report 2.1 A MiniCAM Referece

10) S. 2191 Alternative Reference Scenario

- This policy scenario uses the same assumptions about technology and international action used in the High Technology policy scenarios in the EPA analysis of S. 1766
  - Based on Alternative Reference Scenario
  - Bill as written
  - Substantial growth in nuclear power (nuclear power generation increases by ≈150% from 782 bill. kWh in 2005 to 1,982 bill. kWh in 2050) reflecting possible future policies to promote this technology in S. 2191 and elsewhere
  - Widespread international actions by developed and developing countries over the modeled time period. International policy assumptions are based on those used in the recent MIT report, "Assessment of U.S. Cap-and-Trade Proposals"
    - Group 1 countries (Kyoto group less Russia) follow an allowance path that is falling gradually from the simulated Kyoto emissions levels in 2012 to 50% below 1990 in 2050
    - Group 2 countries (rest of world) adopt a policy beginning in 2025 that returns and holds them at year 2015 emissions levels through 2034, and then returns and maintains them at 2000 emissions levels from 2035 to 2050

FMPA-POD1-00068

HEARING EXHIBIT - 00000230

EPA Models and Corresponding GHG Mitigation

S. 280 Sectors		Economy-wide Computable General Equilibrium (CGE) Models		Models Used to Provide Inputs to CGEs				Partial Equilibrium Model (Uses CGE Outputs)
		ADAGE	IGEM	NCGM	FASOM	GTM	MiniCAM	IPM
Domestic	Electricity Generation	All GHGs	All GHGs					CO_2
	Transportation	All GHGs	All GHGs					
	Industry	All GHGs	All GHGs	CH_4, N_2O, F-gases				
	Commercial	All GHGs	All GHGs					
	Agriculture (& Forestry)	All GHGs	All GHGs		CO_2, CH_4, N_2O			
	Residential	All GHGs	All GHGs	CH_4, N_2O,				
International Credits*				CH_4, N_2O, F-gases		CO_2	CO_2, CH_4, N_2O, F-gases	

* International allowance and domestic offset markets were analyzed using EPA's spreadsheet tool which combines results from the NCGM, FASOM, GTM and MiniCAM models.

ADAGE	Applied Dynamic Analysis of the Global Economy (Ross, 2007)
IGEM	Intertemporal General Equilibrium Model (Jorgenson, 2007)
IPM	Integrated Planning Model (EPA, 2007)
NCGM	EPA's non-CO_2 GHG spreadsheet tools for estimating projections and mitigation of CH_4, N_2O, and F-gases (EPA, 2005)
FASOMGHG	Forest and Agriculture Sector Optimization Model, GHG version (EPA, 2005)
GTM	Global Timber Model (Sohngen, 2006)
MiniCAM	Mini-Climate Assessment Model (Edmonds, 2005)

EMPA-POD1-00069

HEARING EXHIBIT - 00000231

Modeling Limitations*

- The Energy Independence and Security Act (EISA) of 2007
  - This analysis of S. 2191 was initiated before the signing of the Energy Independence and Security Act of 2007. The Energy Act is expected to have significant implications for the U.S. Reference Case emissions of greenhouse gases, and is expected to reduce the costs of compliance with S. 2191.
  - EPA is releasing this analysis of S. 2191 based on the EPA Reference Scenario assumptions used for the previously released analyses of S. 280 and S.1766 to facilitate comparison of the three bills.
  - EPA plans to re-analyze S. 2191 using a reference scenario based on the revised *Annual Energy Outlook 2008* which will include the EIA analysis of the 2007 Energy Bill.
  - EPA plans to release the revised analysis including EISA in the reference case in early June, 2008.

* Additional modeling limitations can be found in *Appendix 1: Modeling Approach and Limitations*

FMPA-POD1-00070

HEARING EXHIBIT - 00000232

Modeling Limitations (con't)

- Alternative Reference Scenario and the preliminary AEO 2008 Reference Case
  - *AEO 2008* forecasts lower CO_2 emissions than the *AEO 2006* Reference case used in EPA's models due to:
    - Slower rate of growth in GDP due to a lower estimate of growth in labor productivity,
    - Higher prices for crude oil and natural gas, and
    - Slower projected growth in energy demand.
  - The *AEO 2006 High Technology Case*, however is closer to the CO_2 emissions in the *AEO 2008*, although for different reasons. The EPA Alternative Reference Scenario is based on the EIA *AEO 2006* High Technology Case.
    - Corporate Average Fuel Economy is assumed to be 9% higher than in the reference case (35.5 MPG for automobiles and 27.1 MPG for light trucks). The Energy Act would require a 25% improvement.
    - Ethanol (Corn or Cellulosic) is not assumed to be consumed on the scale required by the new Renewable Fuels Standard.
    - The AEO High Technology Case assumes improvement in end use energy efficiency in residential, commercial and industrial applications, but EPA does not have the data to compare these to the standards required by the Energy Act.

EPA-POD1-00071

HEARING EXHIBIT - 00000233

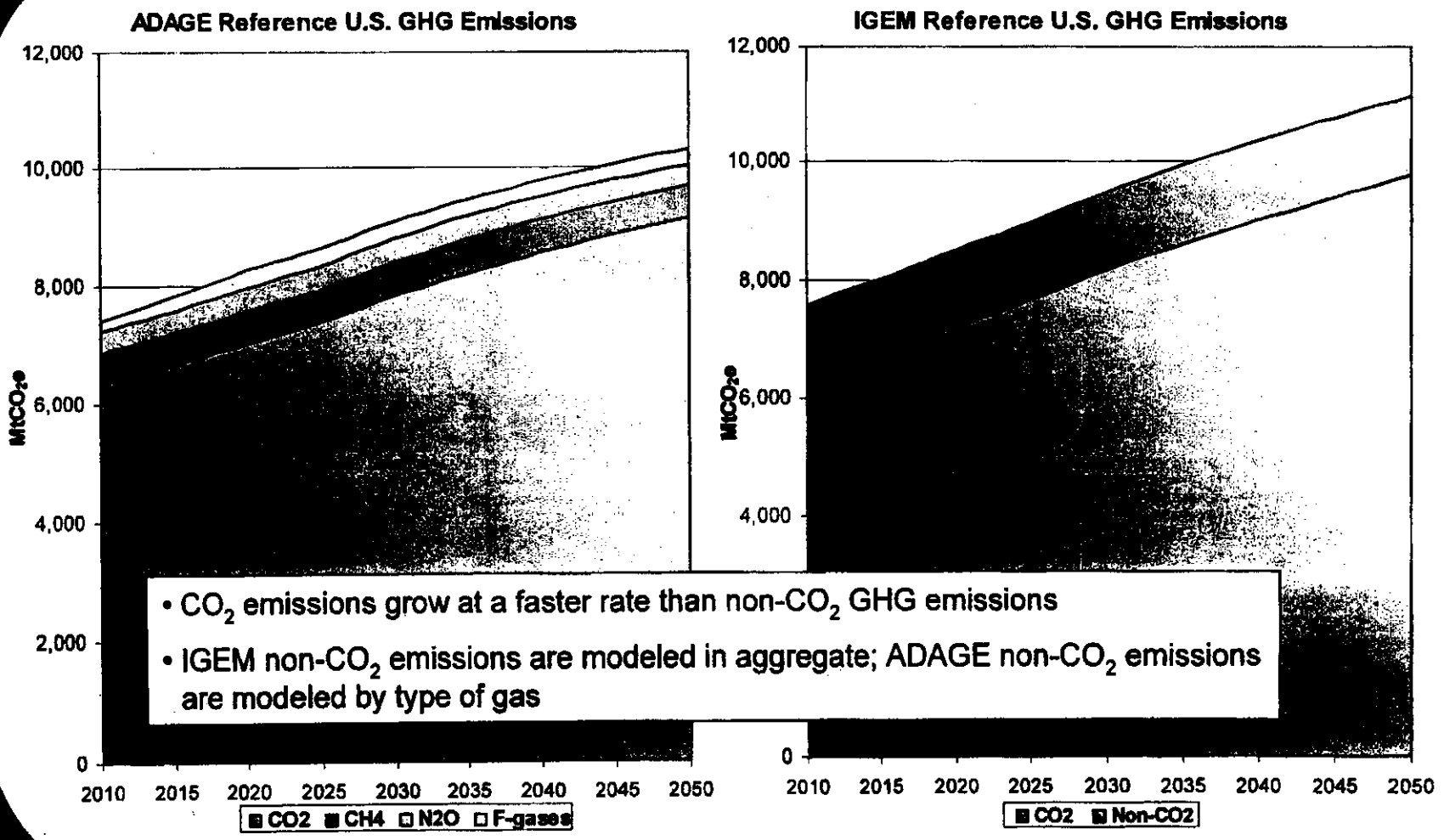
GHG Emissions Results

FMPA-POD1-00072

HEARING EXHIBIT - 00000234

Results: Scenario 1 – Reference

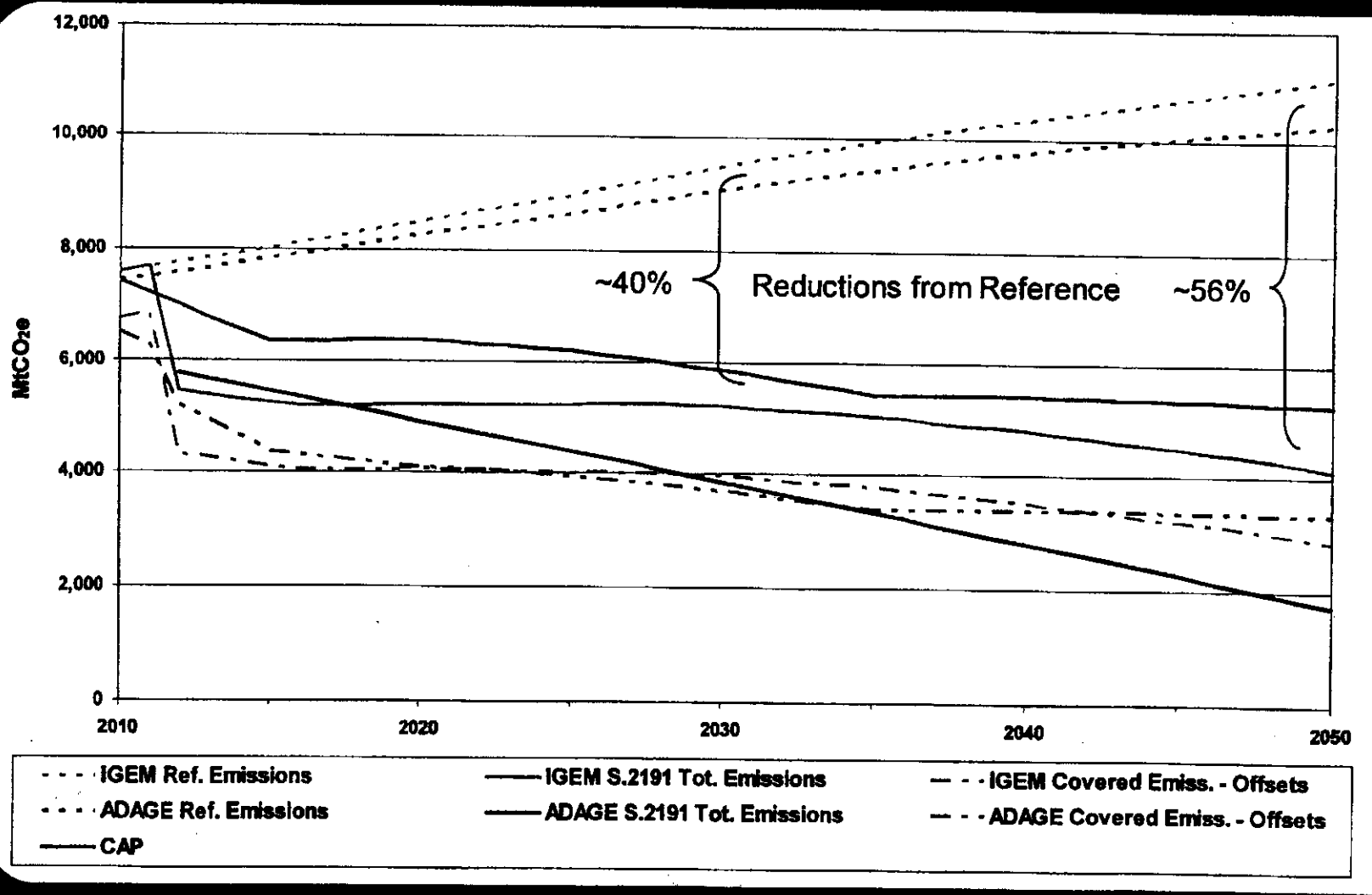
U.S. GHG Emissions



FMPA-POD1-00073
HEARING EXHIBIT - 00000235

Results: Scenario 2 - S. 2191

U.S. GHG Emissions



FMPA-POD1-00074
HEARING EXHIBIT - 00000236

Results: Scenario 2 - S. 2191

U.S. GHG Emissions

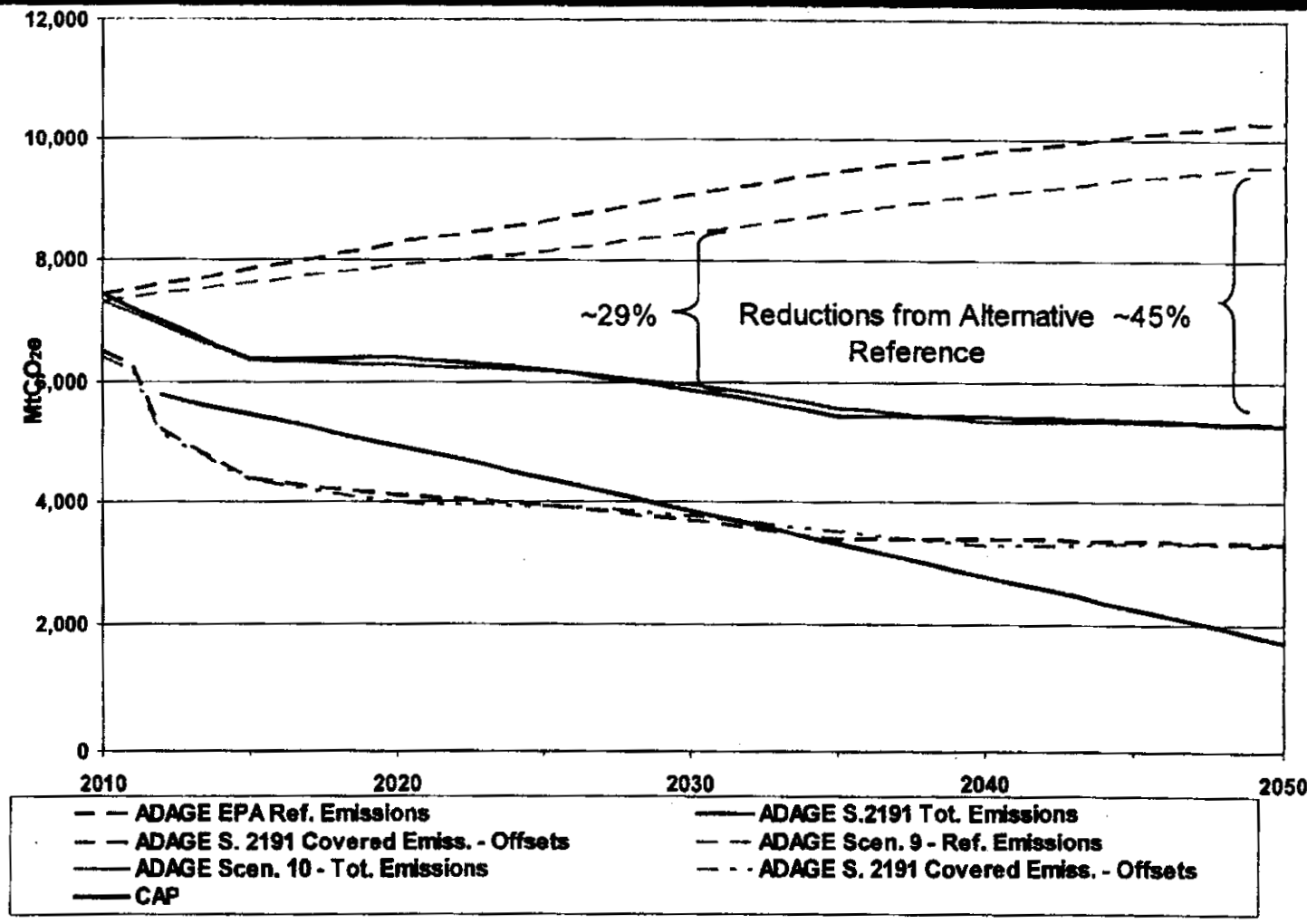
- The previous chart shows the emissions results for S. 2191.
- The two dotted lines at the top are the Reference Scenario emissions of IGEM and ADAGE.
- At the bottom of the chart, the black line is the cap on covered sector emissions.
- The dashed blue and green lines show the emissions of covered sectors, taking into account purchases of domestic offsets and international credits.
- The solid blue and green lines show total U.S. emissions under S. 2191. These levels include emissions from non-covered sectors.
  - In 2030, total U.S. emissions under S. 2191 are reduced in IGEM by 4,276 $MtCO_2e$ from the Reference Scenario (45% reduction) and 3,101 $MtCO_2e$ in ADAGE (34% reduction).
  - In 2030, total U.S. emissions under S. 2191 are 16% below 1990 levels in IGEM, and 6% below 1990 levels in ADAGE.
  - In 2050, total U.S. emissions under S. 2191 are 34% below 1990 levels in IGEM, and 15% below 1990 levels in ADAGE.
- Note that the emissions reductions resulting from S. 2191 are larger in IGEM than in ADAGE. This is the result of two factors:
  - While the reference case for both models is tuned to the AEO 2006 forecast, that forecast only runs through 2030, and the tuning process is not exact. The reference case emissions in IGEM are higher than the reference case emissions in ADAGE, so that IGEM requires greater emissions reductions than ADAGE in order to meet the same target.
  - Additionally, the two models use different procedures to model covered versus uncovered emissions, and ADAGE has a larger amount of uncovered emissions. This can be seen in the gap between the 'Covered Emiss. – Offsets' lines and the 'Total Emiss.' lines (noting that similar amounts of offsets are used in both models).
- S. 2191 results in reductions of non-U.S. GHG emissions through U.S. purchases of international credits, so the bill actually reduces global GHG emissions by more than the solid blue and green lines indicate. The bill results in the purchase of 601 $MtCO_2e$ of international credits in 2030, which is approximately six percent of the U.S. Reference Scenario emissions.

FMPA-POD1-00075

HEARING EXHIBIT - 00000237

Results: Scenario 10 – S.2191 Alternative Reference

U.S. GHG Emissions (ADAGE)

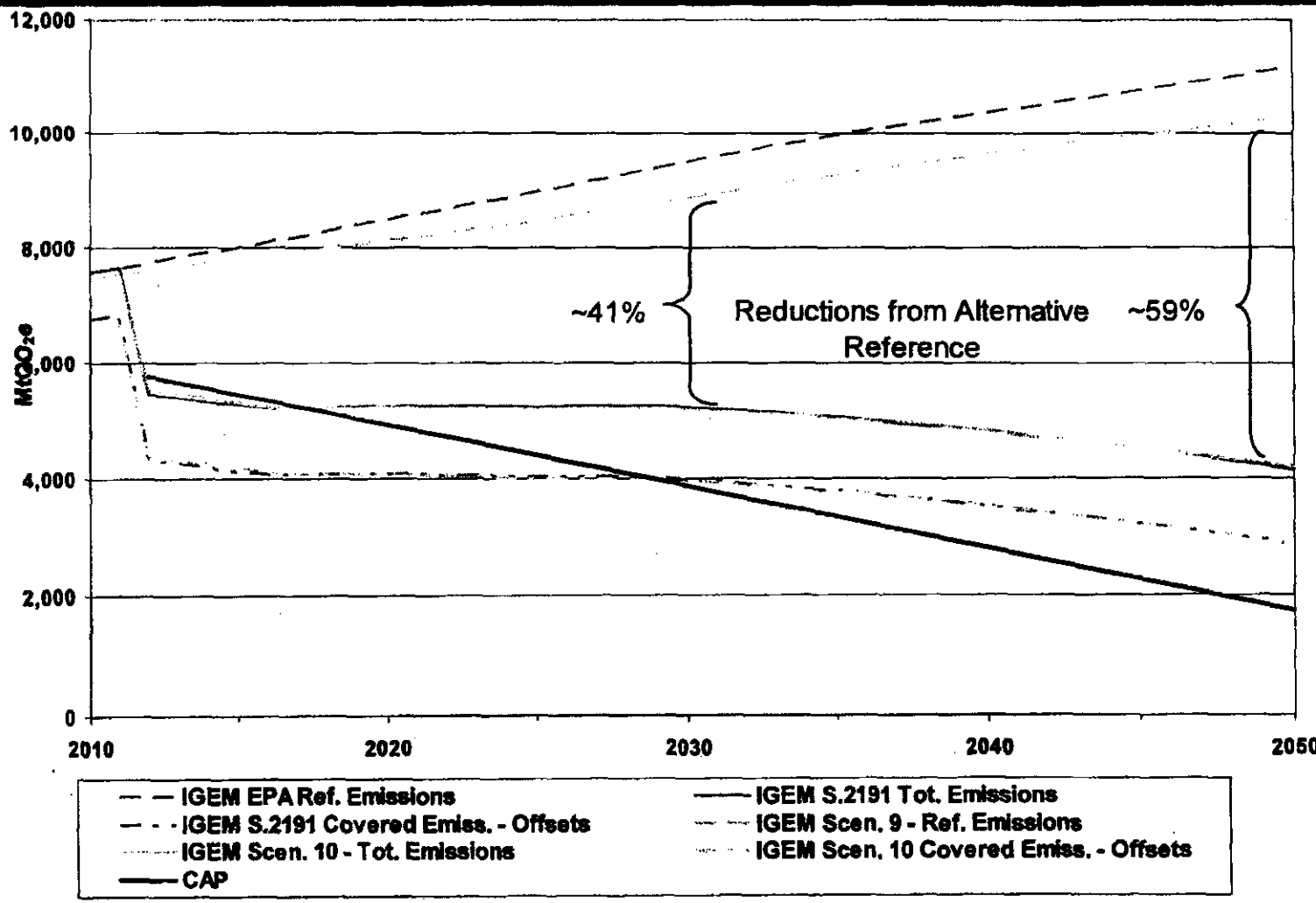


FMPA-POD1-00076

HEARING EXHIBIT - 00000238

Results: Scenario 10 – S.2191 Alternative Reference

U.S. GHG Emissions (IGEM)

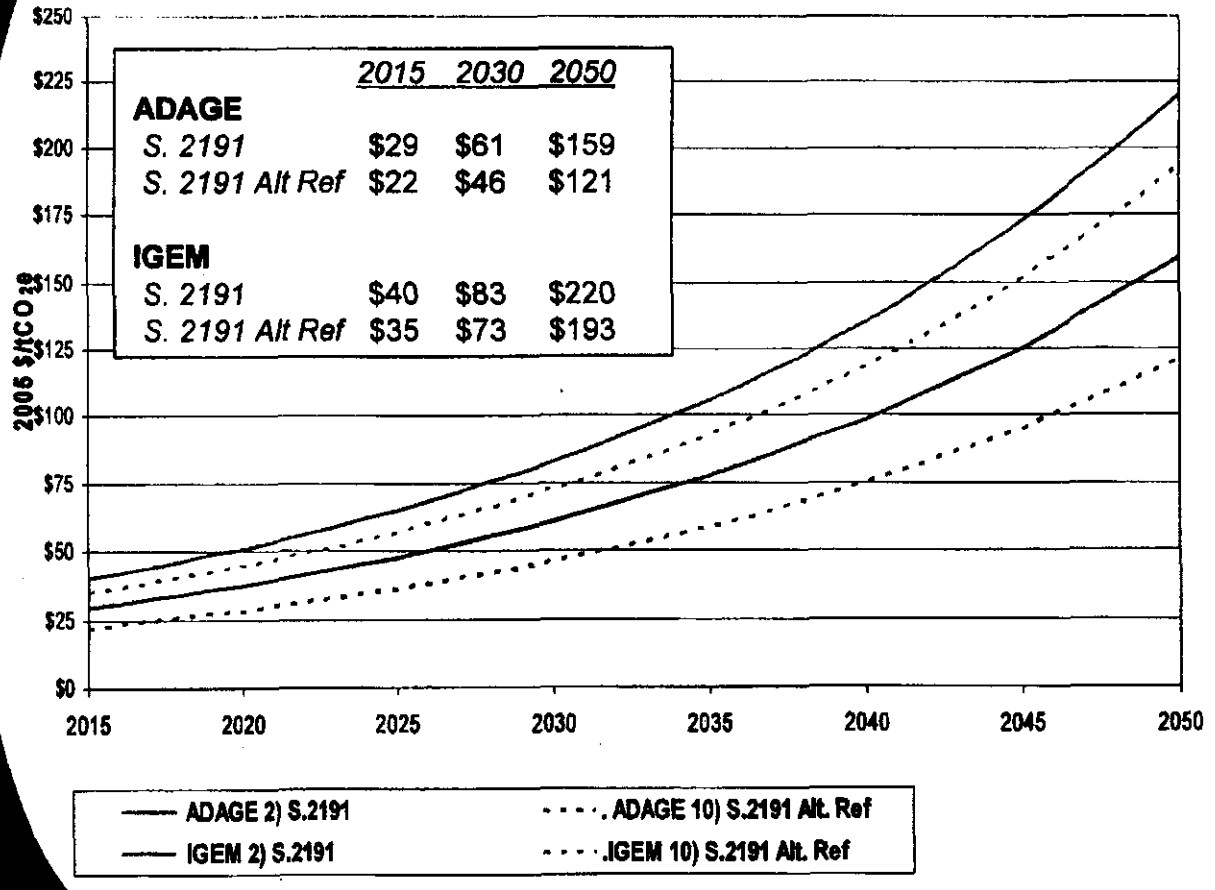


FMPA-POD1-00077

HEARING EXHIBIT - 00000239

Results: Scenario 2 – S. 2191, Scenario 10 – S. 2191 Alt. Ref.

GHG Allowance Prices



- The $61 - $83 range of 2030 allowance prices only reflects differences in the models and does not reflect other scenarios or additional uncertainties discussed elsewhere.
- Note that although the offset price differs from the allowance price, these prices do reflect the use of offsets and international credits.

Comparison with Other Analyses

	2015	2030	2050
MIT*	$48	$86	$189
CRA**	$48	$76	~$600

* Paltsev et al., "Assessment of U.S. Cap-and-Trade Proposals – Appendix D: Analysis of the Cap and Trade Features of the Lieberman-Warner Climate Security Act (S. 2191)" 2007. *LW + 15% Credits + CCS Subsidy Scenario.*

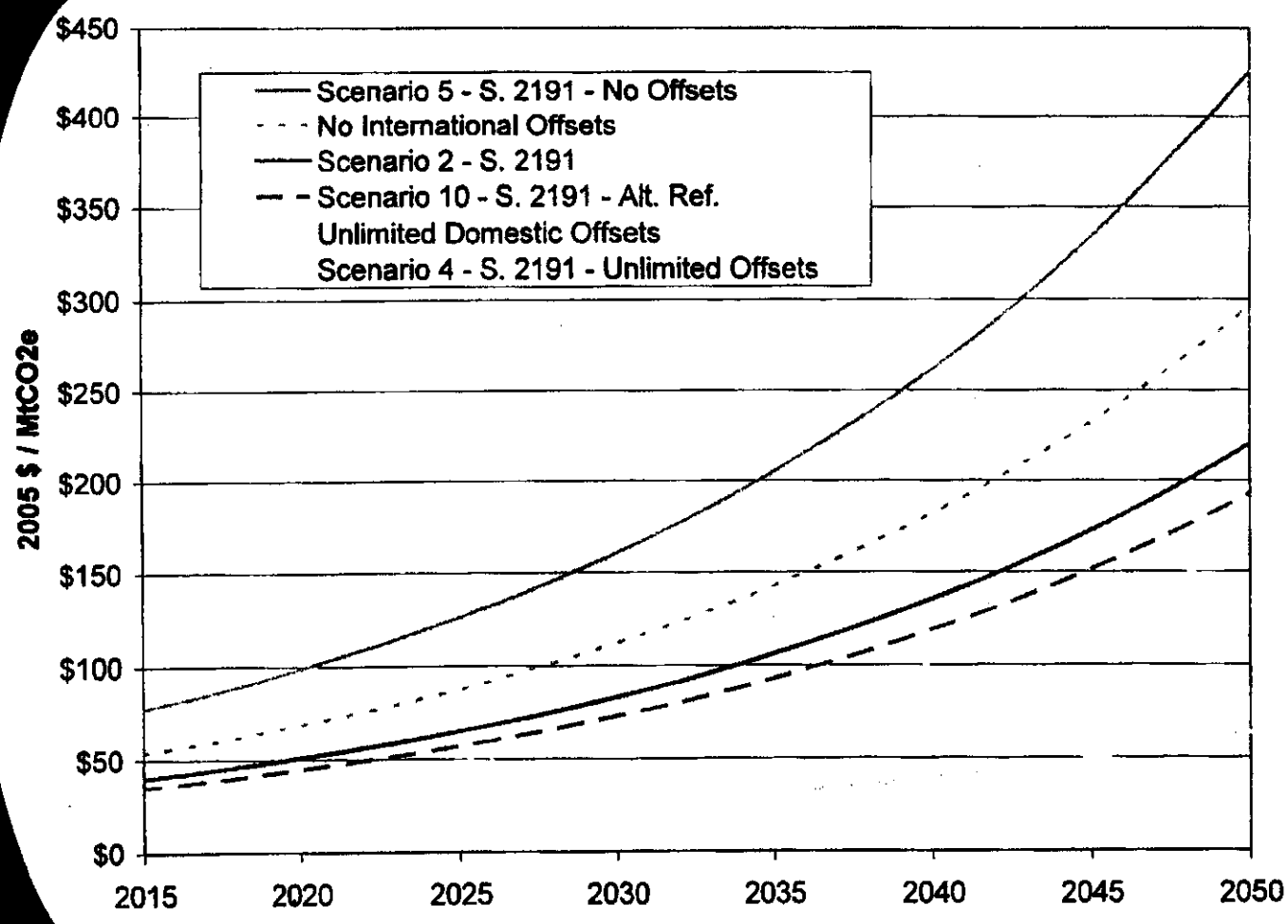
** CRA International, "Economic Modeling of the Lieberman-Warner Bill: S. 2191 as Reported by Senate EPW," January 2008.

FMPA-POD1-00078

HEARING EXHIBIT - 00000240

Scenario Comparison

GHG Allowance Prices (IGEM)



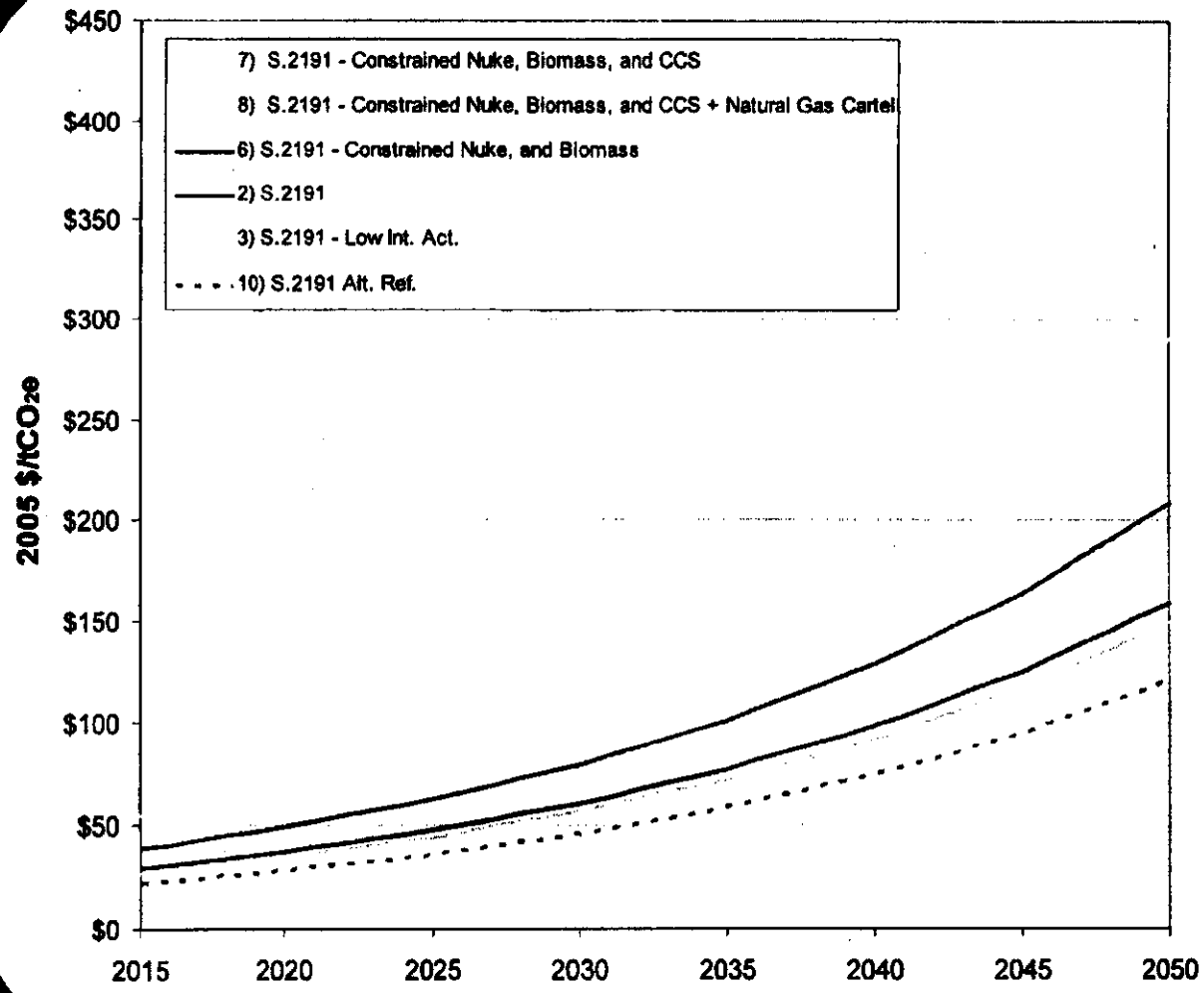
- Compared to the variation in allowance prices between the various alternative technology scenarios, there is a greater variation in allowance prices amongst the alternative offset and international credit scenarios.
- Allowing the unlimited use of domestic offsets and international credits can reduce allowance prices by 71% compared to scenario 2.
- Allowing the unlimited use of just domestic offsets can reduce allowance prices by 26% compared to scenario 2.
- If international credits are not allowed, allowance prices increase by 34% compared to scenario 2.
- If both international credits and domestic offsets are not allowed, allowance prices increase by 93% compared to scenario 2.
- Allowance prices are 12% lower under the alternative reference case compared to scenario 2.

EMPA-POD1-00079

HEARING EXHIBIT - 0000241

Scenario Comparison

GHG Allowance Prices (ADAGE)



- Compared to the variation in allowance prices between the various alternative offset and international credit scenarios, there is a smaller variation in allowance prices amongst the alternative technology scenarios.
- Allowance prices are 86% higher in the constrained nuclear, biomass, and CCS scenario compared to scenario 2. The natural gas cartel has minimal influence on the allowance price.
- Allowance prices are 32% higher in the constrained nuclear, and biomass scenario compared to scenario 2.
- Allowance prices are 24% lower under the alternative reference case compared to scenario 2.

FMPA-POD1-00080

HEARING EXHIBIT - 00000242

Scenario Comparison

GHG Allowance Prices

Table: Allowance Price Comparison (2005 $/tCO2e)

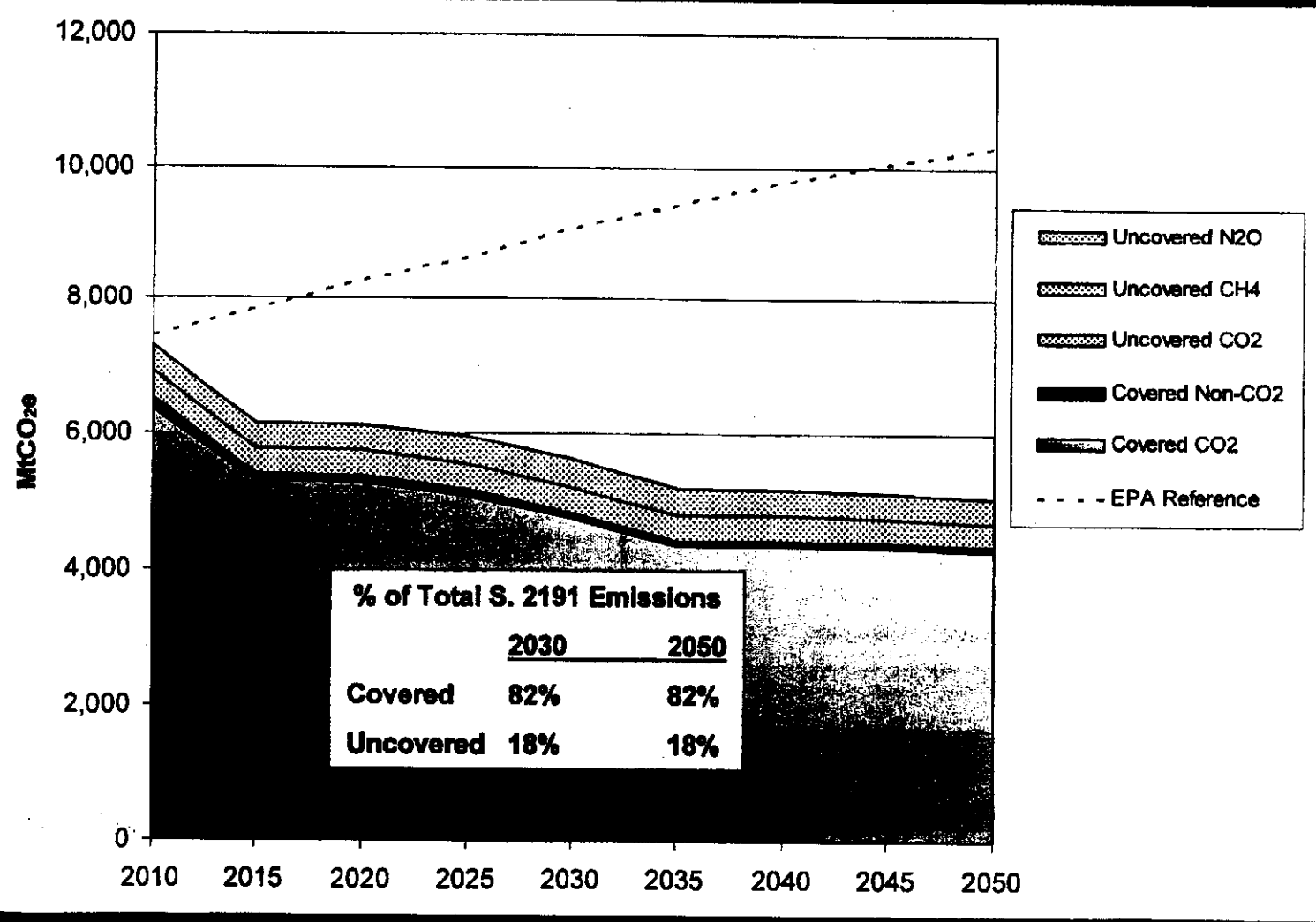
	2015	2020	2025	2030	2035	2040	2045	2050
1) EPA Reference								
ADAGE	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2) S. 2191								
ADAGE	$29	$37	$48	$61	$77	$98	$125	$159
IGEM	$40	$51	$65	$83	$106	$135	$173	$220
3) S.2191 w/ Low International Action								
ADAGE	$27	$35	$44	$56	$72	$92	$117	$149
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
4) S.2191 w/ Unlimited Offsets								
ADAGE	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
IGEM	$11	$15	$19	$24	$30	$39	$50	$63
5) S.2191 w/ No Offsets								
ADAGE	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
IGEM	$77	$98	$125	$160	$205	$261	$333	$425
6) S.2191 Constrained Nuclear & Biomass								
ADAGE	$39	$49	$63	$80	$101	$129	$164	$208
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
7) S.2191 Constrained Nuclear & Biomass, and CCS								
ADAGE	$55	$69	$88	$112	$142	$181	$229	$290
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
8) S.2191 Constrained Nuclear & Biomass, and CCS + Beyond Kyoto + Natural Gas Cartel								
ADAGE	$55	$70	$88	$112	$142	$180	$228	$288
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
9) Alternative Reference								
ADAGE	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
10) S.2191 Alt. Ref.								
ADAGE	$22	$28	$36	$46	$59	$75	$95	$121
IGEM	$35	$47	$57	$71	$89	$114	$145	$193

FMPA-POD1-00081

HEARING EXHIBIT - 00000243

Results: Scenario 2 - S. 2191

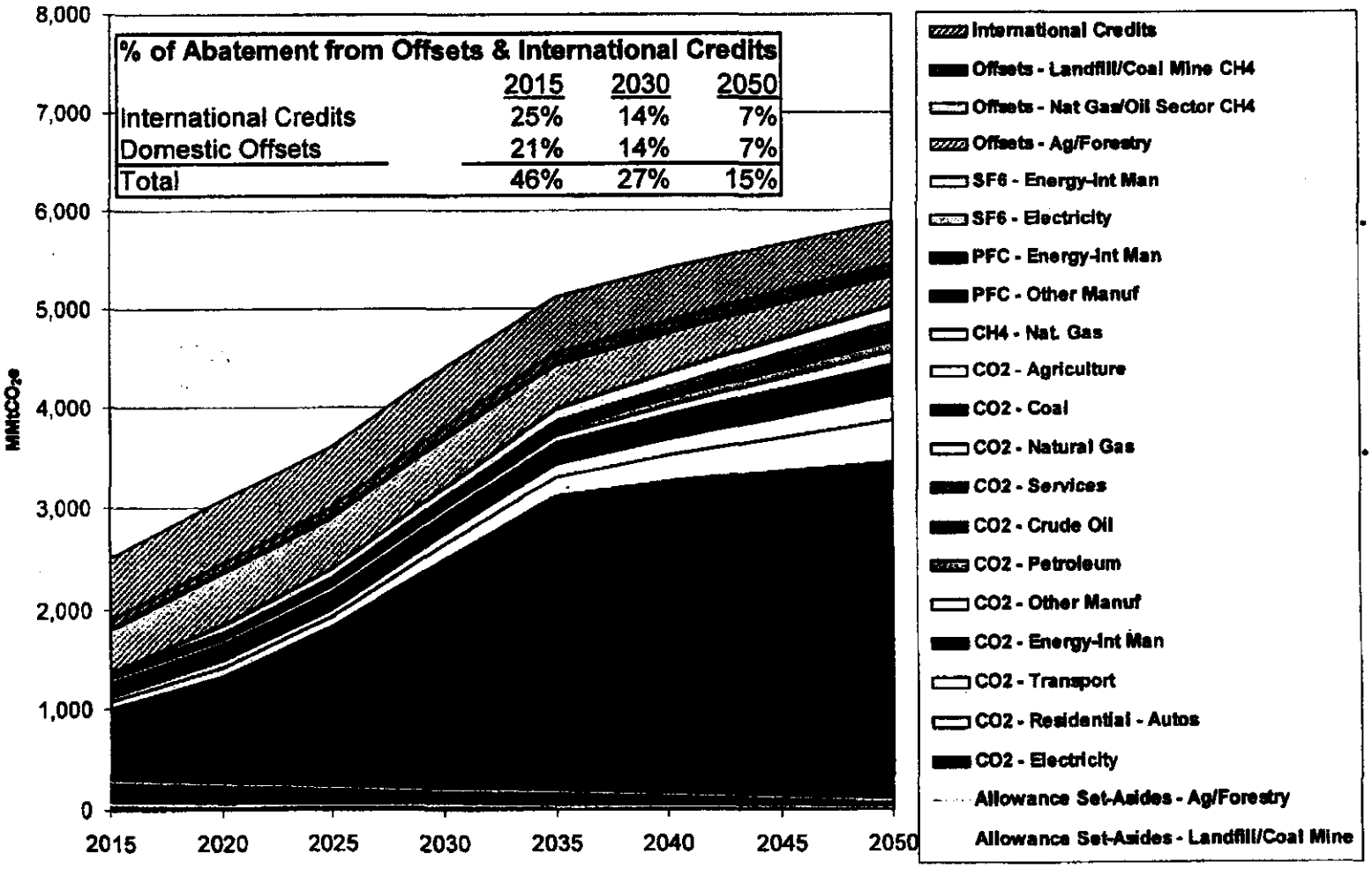
Total U.S. GHG Emissions (ADAGE)



FMPA-POD1-00082
HEARING EXHIBIT - 00000244

Results: Scenario 2 - S. 2191

Sources of GHG Abatement (ADAGE)



- S. 2191 allows offsets and international credits to each make up 15% of the total allowance submissions requirement.
- The quantity of offsets and international credits allowed decreases as allowance submissions decrease.
- Since the quantity of offsets allowed is decreasing over time and the quantity of abatement is increasing over time, offsets make up a large fraction of abatement in the early years of the policy, and there contribution to total abatement decreases over time.

HEARING EXHIBIT - 00000245

Results: Scenario 2 - S. 2191

Sources of GHG Abatement (ADAGE)

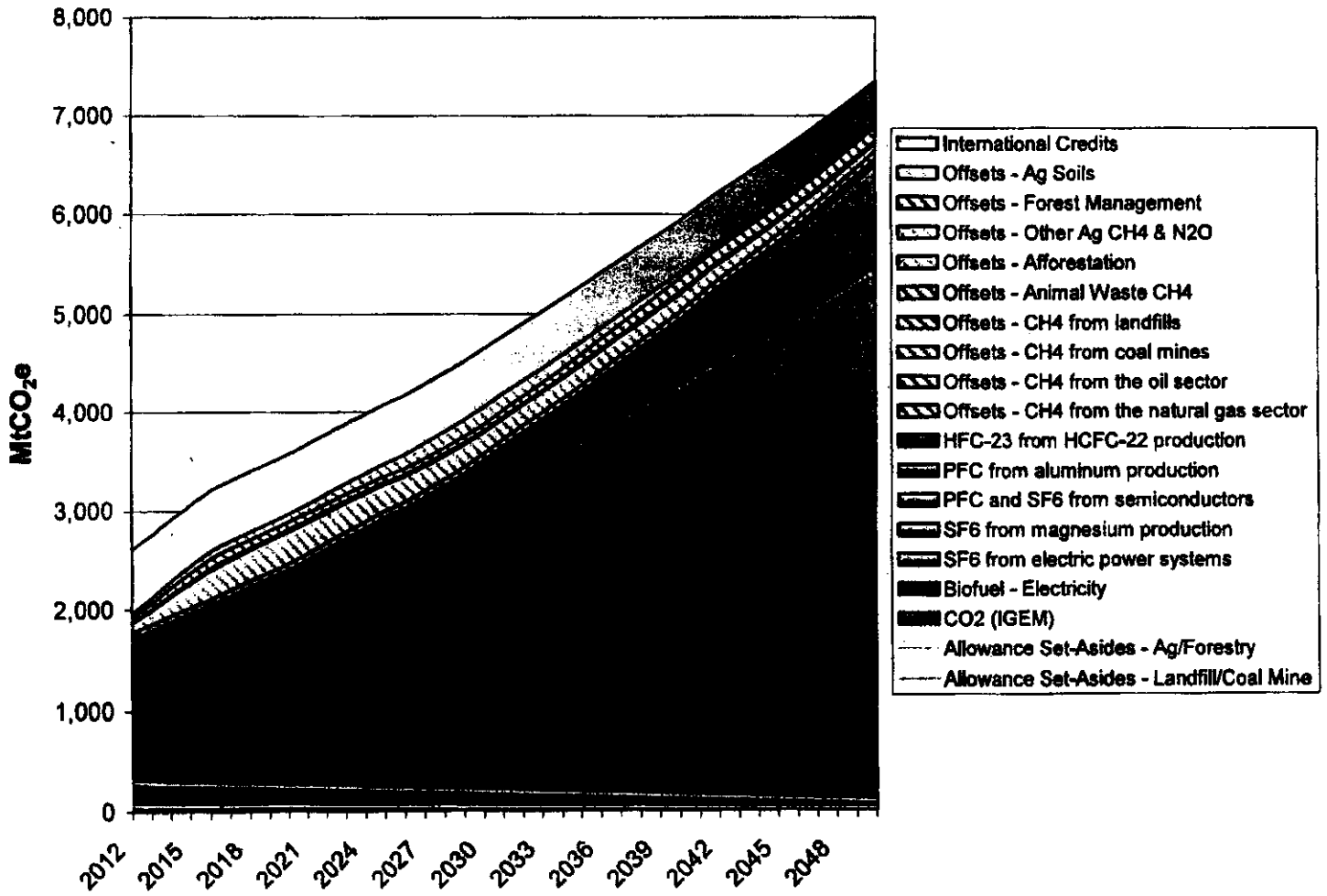
- The previous chart shows the sources by sector of GHG abatement under S. 2191.
- CO_2 emissions from the electricity sector (the blue area at the bottom) represent the largest source of domestic reductions.
- The area toward the top of the chart shaded with hashed lines show emissions reductions from non-covered sectors (offsets) and international credits.
  - International credits (the hashed area at the very top) are limited to make up no more than 15% of compliance in any year. Given this limit, in the early years they make up a larger portion of abatement (25% in 2015), and a smaller portion of abatement in later years (14% in 2030 and 7% in 2050).
    - Note that in the early years when cap level is relatively high compared to reference emissions, and a relatively small amount of abatement is required, offsets and international credits while limited to 15% of compliance, may make up a larger percentage of abatement.
  - Domestic offsets are similarly limited to make up no more than 15% of compliance in any year. Among domestic offsets, the agricultural and forestry sector (the yellow hashed area) supplies the most abatement.
- The light green and blue lines at the bottom represent GHG abatement from allowance set-asides. This abatement is additional to the abatement in covered sectors and offset projects that is used to meet the cap.
- Commercial transportation and personal vehicles ("residential autos") are represented by the solid light blue and green areas above the electricity sector.
  - Note that ADAGE does not explicitly model new developments in transportation technologies – these reductions occur in the model due to the price changes resulting from the imposition of the upstream cap on emissions from the petroleum sector.
- The growth of abatement from CO_2 from the electricity sector drops off sharply after 2035. This occurs because by 2035 advanced coal with carbon capture and storage technology has displaced almost all traditional fossil generation in the model, so further the opportunities for further emissions reductions in the electricity sector are limited.
- Since the electricity sector plays a key role in GHG abatement and the CGE models have a limited representation of technology, we used the IPM model to examine the electricity sector in more detail through 2025.

EPA-POD1-00083

HEARING EXHIBIT - 00000246

Results: Scenario 2 - S. 2191

Sources of GHG Abatement (IGEM)



- S. 2191 allows offsets and international credits to each make up 15% of the total allowance submissions requirement.
- The quantity of offsets and international credits allowed decreases as allowance submissions decrease.
- Since the quantity of offsets allowed is decreasing over time and the quantity of abatement is increasing over time, offsets make up a large fraction of abatement in the early years of the policy, and there contribution to total abatement decreases over time.

FMPA-POD1-00084

HEARING EXHIBIT - 00000247

Results: Scenario 2 - S. 2191

Sources of GHG Abatement (IGEM)

- The previous chart shows, for the IGEM model, the sources of CO_2 and non-CO_2 GHG abatement under S. 2191.
- IGEM does not break out CO_2 emissions by sector, so the bottom purple area represents all energy related CO_2 emissions abatement within IGEM.
  - The other sources of abatement represented here are derived from EPA's non-CO_2 GHG spreadsheet tools for estimating projections and mitigation of CH4, N_2O, and F-gases (NCGM), and the Forest and Agriculture Sector Optimization Model, GHG version (FASOMGHG).
- The areas toward the top of the chart shaded with hashed lines show emissions reductions from domestic offsets and the red shaded area at the very top shows international credits
  - International credits are limited to make up no more than 15% of compliance in any year. Given this limit, in the early years they make up a larger portion of abatement (20% in 2015), and a smaller portion of abatement in later years (13% in 2030 and 6% in 2050).
    - Note that in the early years when cap level is relatively high compared to reference emissions, and a relatively small amount of abatement is required, offsets and international credits while limited to 15% of compliance, may make up a larger percentage of abatement.
  - Domestic offsets are similarly limited to make up no more than 15% of compliance in any year. The majority of domestic offsets come from the agriculture and forestry sectors.
- The light green and blue lines at the bottom represents GHG abatement from allowance set-asides. This abatement is additional to the abatement in covered sectors and offset projects that is used to meet the cap.

FMPA-POD1-00085

HEARING EXHIBIT - 00000248

Detailed Near-Term Electricity Sector Modeling Results

FMPA-POD1-00086

HEARING EXHIBIT - 00000249

Detailed Electricity Sector Modeling with IPM

Motivation for Using the Integrated Planning Model (IPM):

- The CGE models used for this analysis do not have detailed technology representations; they are better suited for capturing long-run equilibrium responses than near-term responses.
- Since the electricity sector plays a key role in GHG mitigation, and the near-term response in the electricity sector is of particular interest, we have employed the Integrated Planning Model (IPM) model to shed further light on the near-term impact of S. 2191 on the electricity sector as a complement to the broader picture presented by the CGE models.

Power Sector Modeling (EPA Base Case v3.01 using IPM):

- This version of IPM builds off recently released EPA Base Case v3.0, with the following updates for purposes of modeling carbon policies:
  - Carbon capture and storage (for new plants)
  - Biomass co-firing option
  - Constraints on new nuclear, renewable, and advanced coal (with CCS) capacity

Modeling Approach:

For this analysis, EPA's Base Case v3.01 using IPM was used and incorporated two sets of data from the ADAGE model:

- CO_2 allowance price projections
- Percent change in electricity demand

FMPA-POD1-00087

HEARING EXHIBIT - 00000250

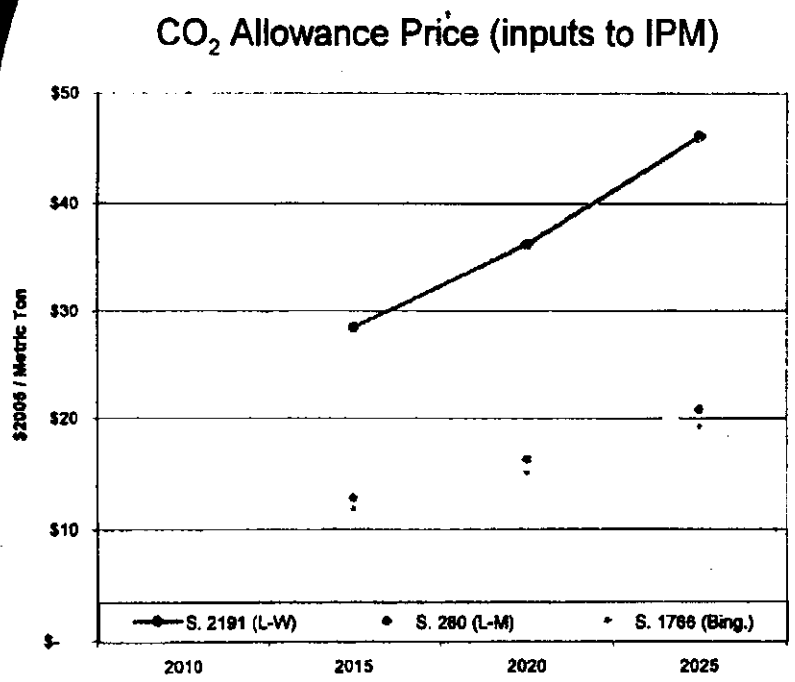
Key Insights from IPM Results for the Near-Term

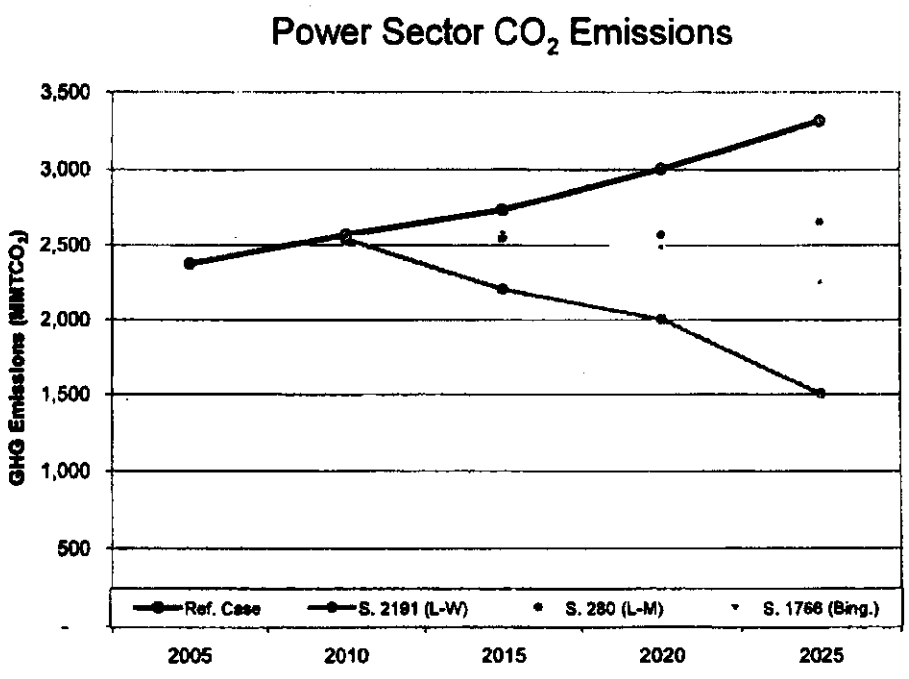
- The reduced electricity demand levels produce the largest share of reductions in the early years (prior to 2020).
- Due to the bonus allowance provision for CCS, GHG allowance prices will be high enough to justify significant penetration of new coal capacity with CCS technology starting in 2015. Further, the carbon price incurred by various emitting technologies (e.g., coal) makes new nuclear plants and renewables more economic to build.
  - Advanced coal with CCS is projected to penetrate at the maximum permissible rate in the model in 2015 and 2025, but not in 2020.
  - A significant number of coal and oil/gas steam units are projected to retire, compared with the reference case.
  - Without the bonus subsidy, IPM projects later penetration of CCS (2025). It also projects less fossil retirement and more renewable penetration.
- Because of considerable uncertainties regarding technology cost, performance, and penetration, as well as uncertainty regarding implementation of complementary measures (such as a Renewable Portfolio Standard (RPS)), it is very difficult to specify bonus allowance ratios to achieve desired deployment of CCS.

FMPA-POD1-00088

HEARING EXHIBIT - 00000251

CO_2 Allowance Prices and Power Sector CO_2 Emissions (IPM)

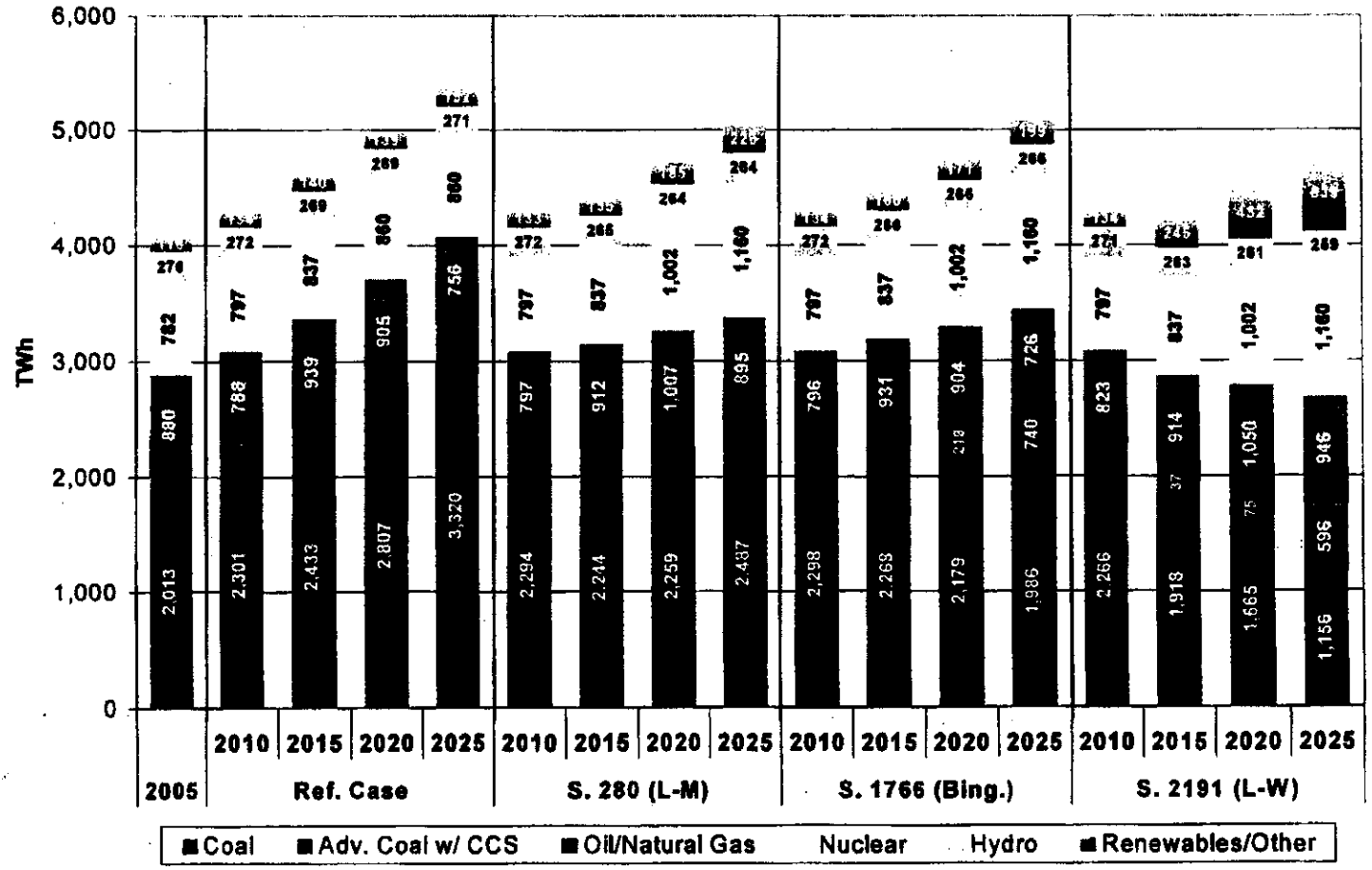




FMPA-POD1-00089

HEARING EXHIBIT - 00000252

Electricity Generation Mix (IPM)

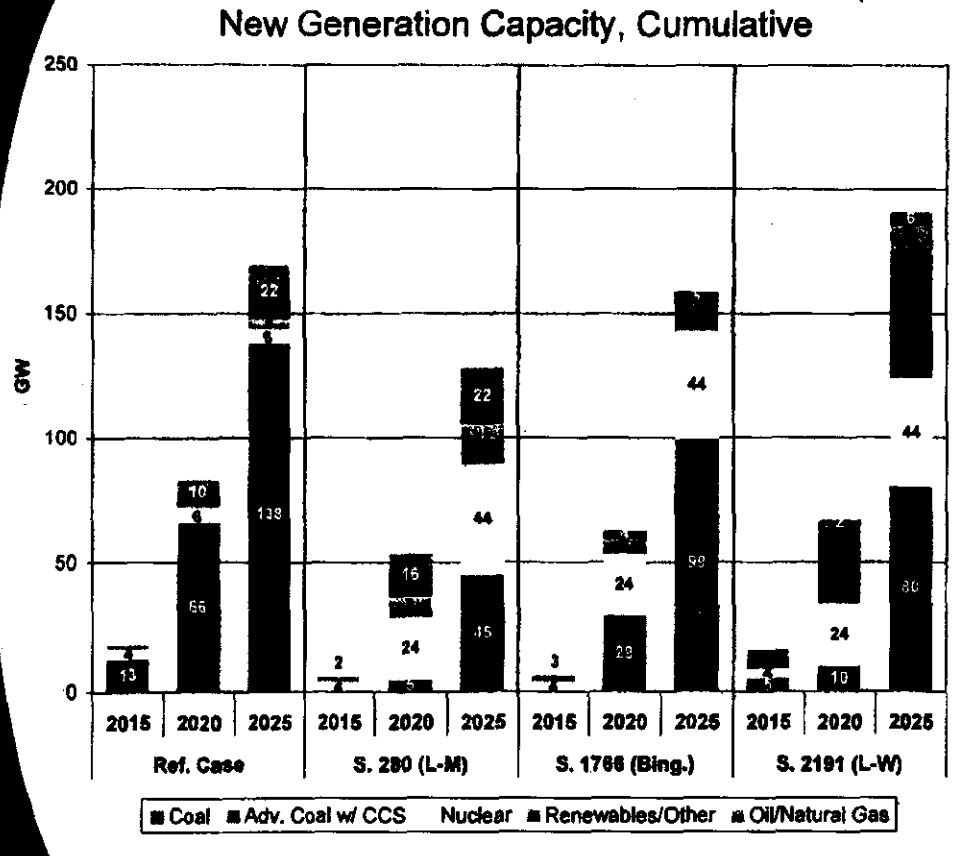


EPA Analysis of S. 2191

FMPA-POD1-00090

HEARING EXHIBIT - 00000253

New Generation Capacity (IPM)



Note: New capacity additions less than 1 GW of capacity are not indicated.

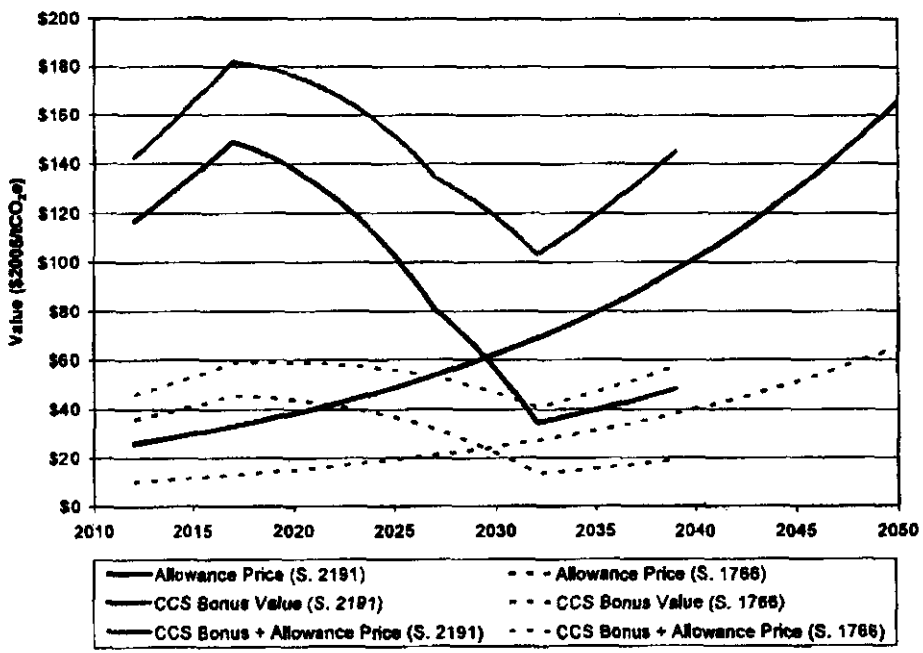
- S. 2191 contains an allowance bonus provision, which is capped, for CO_2 emissions that are captured and sequestered, resulting in significant penetration of new coal capacity with CCS technology (S. 1766 has a similar provision).
  - Bonus allowances go unused in 2015 only, when there is a 5 GW constraint on new adv. coal with CCS (the bonus is used entirely in all years post-2015).
- In 2025, adv. coal with CCS is economic even without the bonus.
- S. 2191 also results in significant penetration of new nuclear and renewable capacity.
- More capacity is built under S. 2191 because a significant amount of the existing fossil fleet is not economic to operate and must be replaced.

New Capacity Limitations in IPM (Incremental/Cumulative)				
GW	2010	2015	2020	2025
Nuclear	N/A	4	20 / 24	20 / 44
Adv. Coal w/ CCS	N/A	5	70 / 75	70 / 145
Renewables *(Cumulative Only)*	4	24	44	64

FMPA-POD1-00091

HEARING EXHIBIT - 00000254

Bonus Allowances for CCS



Year	Bonus Allowance Rate	
	S. 2191	S. 1766
2012-2017	4.5	3.5
2018	4.2	3.3
2019	3.9	3.1
2020	3.6	2.9
2021	3.3	2.7
2022	3.0	2.5
2023	2.7	2.3
2024	2.4	2.1
2025	2.1	1.9
2026	1.8	1.7
2027	1.5	1.5
2028	1.3	1.3
2029	1.1	1.1
2030	0.9	0.9
2031	0.7	0.7
2032-2039	0.5	0.5

- **Bonus allowances are distributed to entities that implement geological sequestration projects.**
- **The value of the CCS bonus allowances changes with the allowance price and the bonus allowance rate. The kinks in the CCS bonus value curve are due to the changes in the bonus allowance rate over time.**
- **The benefit to sources that capture and sequester CO_2 is the value of the CCS bonus plus the allowance price.**
- **The bonus allowances allocated in S. 2191 are capped (unlike S. 1766) at 4% of the total, but the bonus allowance rate is higher initially.**
- **The bonus leads to earlier and greater penetration of CCS in both Bills. CCS would be deployed in S. 2191 even without the bonus because of higher allowance prices.**

FMPA-POD1-00092

HEARING EXHIBIT - 00000255

Bonus Allowances for CCS Cont'd

Although the bonus allowance rate and allowance prices in S. 2191 are greater than S. 1766, the effective incentive is capped and eventually runs out. As a result, the bonus allowances available under S. 1766 are much greater, which leads to more new coal capacity with CCS than under S. 2191, even though allowance prices are lower in S. 1766.

- It should be pointed out that greater builds of new advanced coal with CCS leads to more retirements of existing capacity, mostly less efficient oil/gas steam and coal units.

Bonus Allowance Comparison in 2020		
	S. 2191	**S. 1766**
Bonus Rate	3.6 allowances for each ton sequestered, total allocations limited to 4% of total	2.9 allowances for each ton sequestered, unlimited # of projects
Projected Allowance Price ($2005/ton)	$38	$15
Effective Bonus ($/ton sequestered)	$176	$59
Effective Incentive after Limit is Exceeded ($/ton)	$38 (allowance price)	$59 (bonus, no limit)

Note: The effective bonus is the product of the allowance prices and the bonus rate, and may not match because of rounding.

FMPA-POD1-00093

HEARING EXHIBIT - 00000256

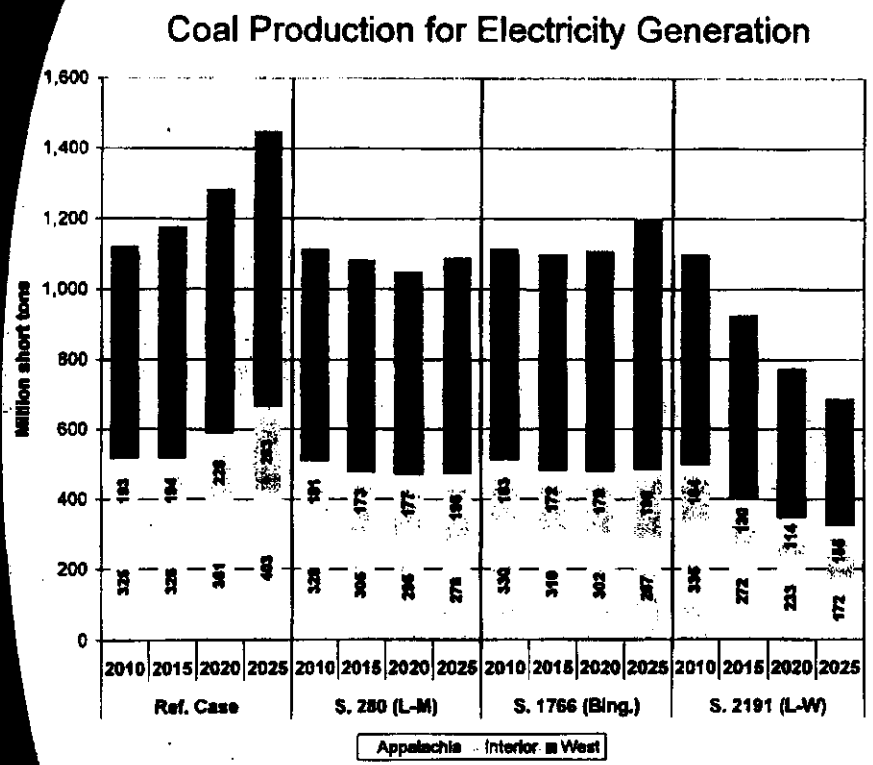
Analysis of Bonus Allowances for CCS

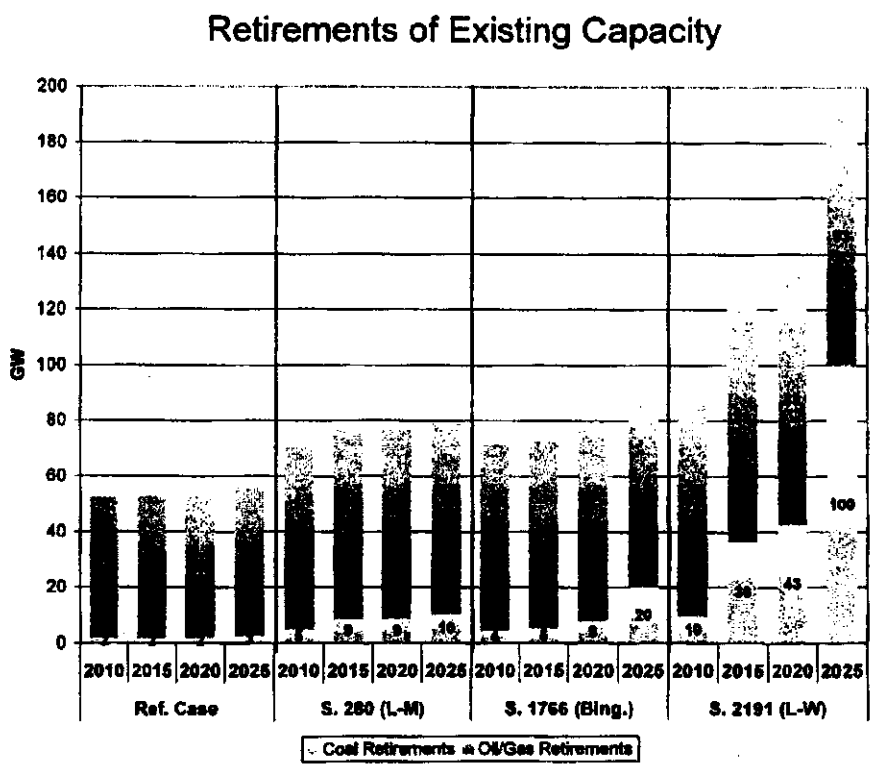
- Purpose: To promote greater and/or earlier investment in carbon capture & storage by offering marketable incentives (in the form of allowances) to the power sector.
- Results: Roughly 80 GW of advanced coal with CCS built by 2025 (in 2025 the bonus allowances are exhausted and advanced coal with CCS is economic).
  - In 2015, advanced coal with CCS is only economic with the bonus allowances. The bonus is enough to incentivize more than 5 MW of advanced coal with CCS. Since the model is constrained to build only 5 MW of CCS, that is the amount built
  - In 2020, advanced coal is only economic with the bonus allowances, however only enough allowances are available to build an additional 5 MW of advanced coal with CCS, significantly less than the 70 MW allowed by the model.
- Observations:
  - Investment in CCS is very sensitive in EPA's IPM analysis to the allowance price and bonus allowance ratio because cost assumptions are somewhat uniform.
  - In reality, there is likely to be more variability in risk profiles, capital costs, and transport/storage costs that would result in a wider range of CCS costs than IPM currently reflects.
  - Complementary policies such as a national Renewable Portfolio Standard could dampen allowance prices. Lower prices combined with increased renewables generation would lessen the need for CCS.
  - The incentive for CCS results in earlier retirements of existing coal capacity than might otherwise take place.

FMPA-POD1-00094

HEARING EXHIBIT - 00000257

Coal Production for Electricity Generation & Retirements of Existing Capacity (IPM)





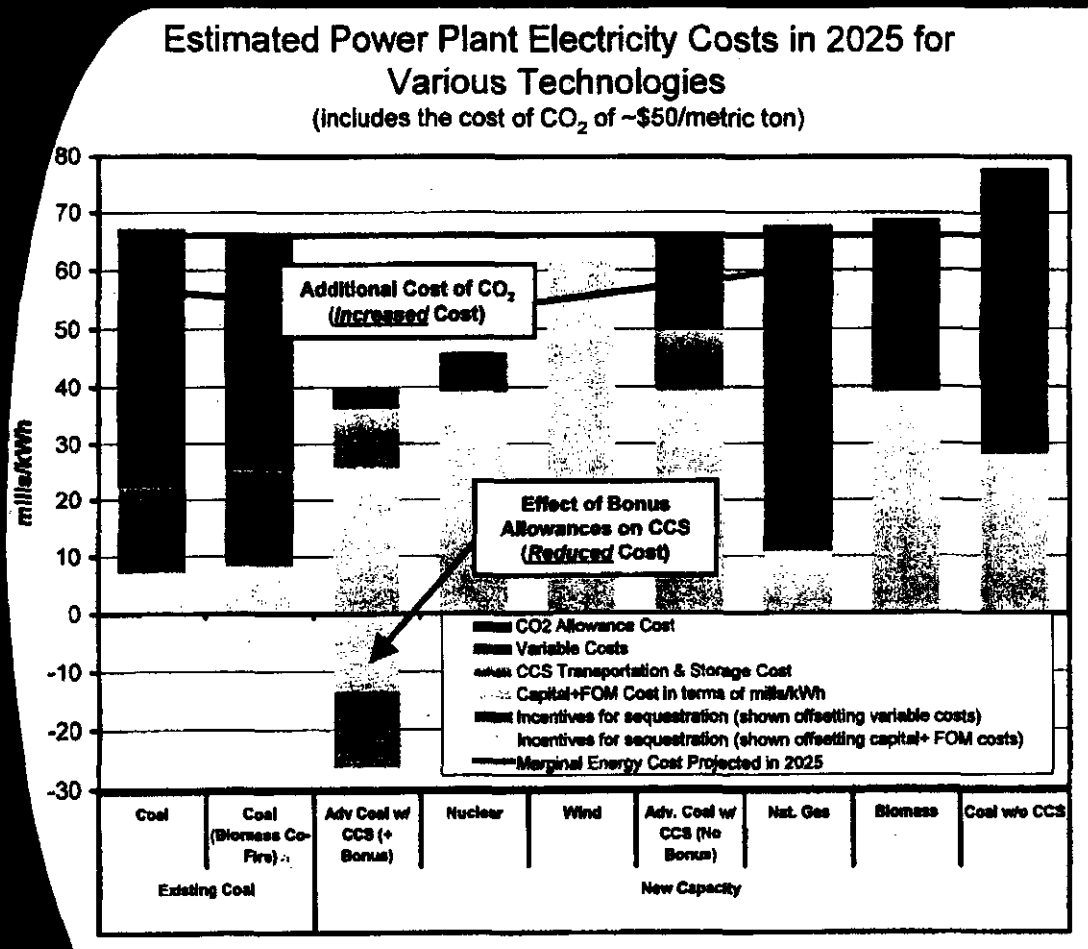
- There is are also considerable re-powering of coal to natural gas in the S. 2191 case.

Note: Regional coal production data includes coal production for power generation only.

FMPA-POD1-00095

HEARING EXHIBIT - 00000258

Near-Term Power Plant Economics with CO_2 Allowance Costs



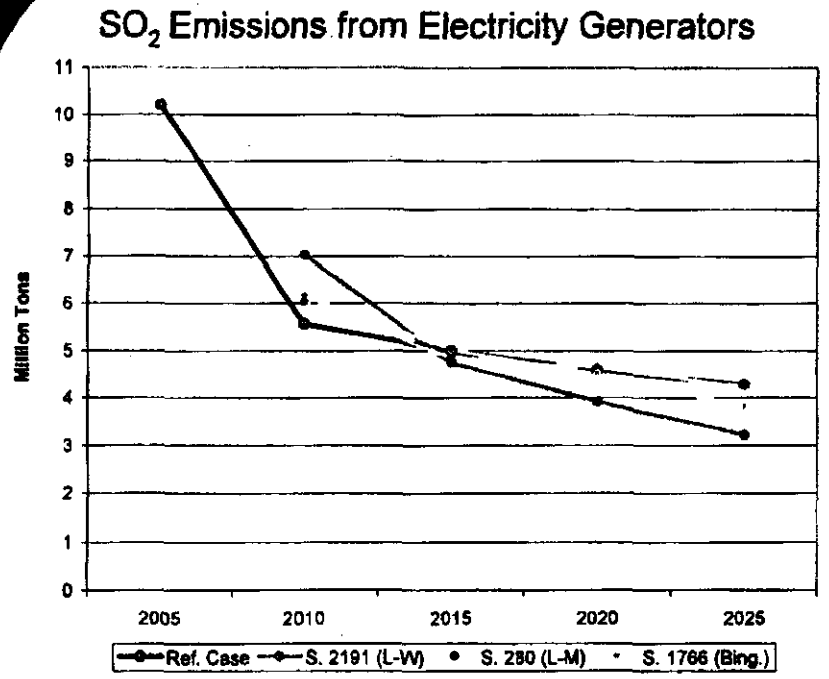
- To illustrate the economics of operating existing and new power technologies, the chart shows the cost of various technologies when the projected CO_2 allowance prices are included.
- Projected CO_2 allowance prices of roughly $50/ton in 2025 increase variable costs of existing plants powered by fossil fuels to the point where many are likely to shut down.
- However, S. 2191 provides significant incentives for CCS technology for coal plants in the form of bonus allowances, resulting in earlier penetration of advanced coal with CCS.

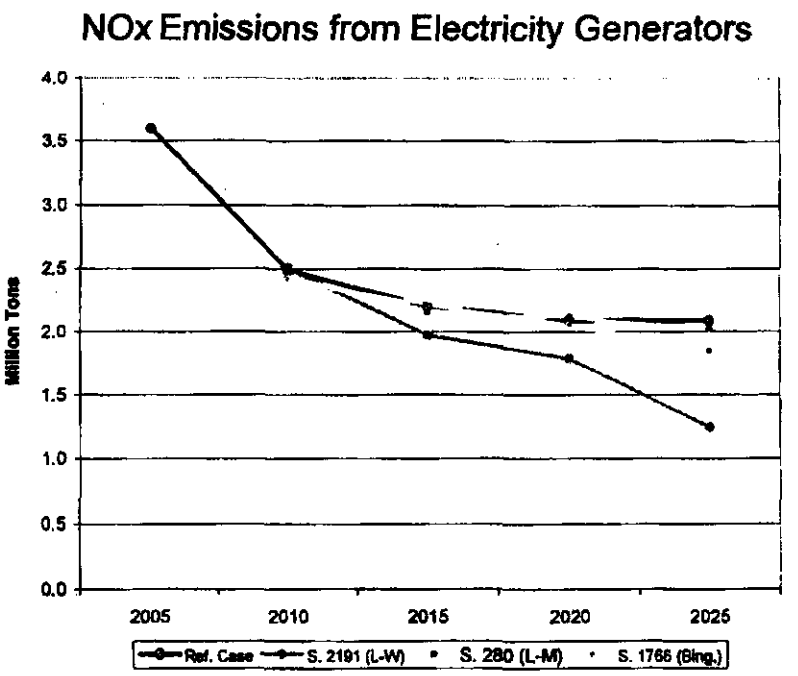
Notes: For the case with bonus allowances, the variable, capital, and fixed O&M costs are actually an aggregate of the solid part and the hashed part but the net cost is only the solid part. For this illustrative calculation, EPA used a conservative efficiency metric for existing coal plants (10,500 Btu/kWh), which most plants currently meet or exceed. The marginal energy cost is defined as the cost of production of the most expensive unit operating in that hour. It includes the cost of fuel, variable O&M cost and the cost of environmental allowances. The capital costs used here are from IPM v3.01, which relies upon EIA capital cost data from AEO 2005. More recently, capital costs have increased with increasing international demand for raw materials. It is not clear how the market will respond to these price increases and whether these increased costs will be sustained over the period of the analysis.

FMPA-POD1-00096

HEARING EXHIBIT - 00000259

Nationwide Power Sector Emissions (IPM)





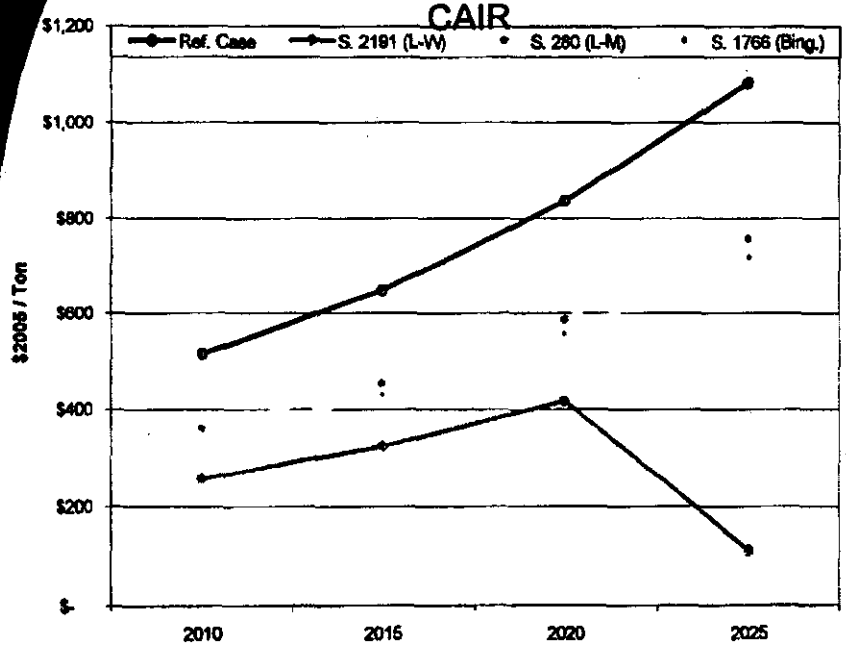
- CO_2 allowance prices projected in S. 2191 influence the timing of SO_2 and NOx emissions because of existing cap and trade programs and emission banking provisions of the CAIR program.
- To a certain extent, short-term changes in emissions (particularly SO_2) are overstated because of the significant number of advanced pollution controls that are currently under construction, which are unlikely to be cancelled.

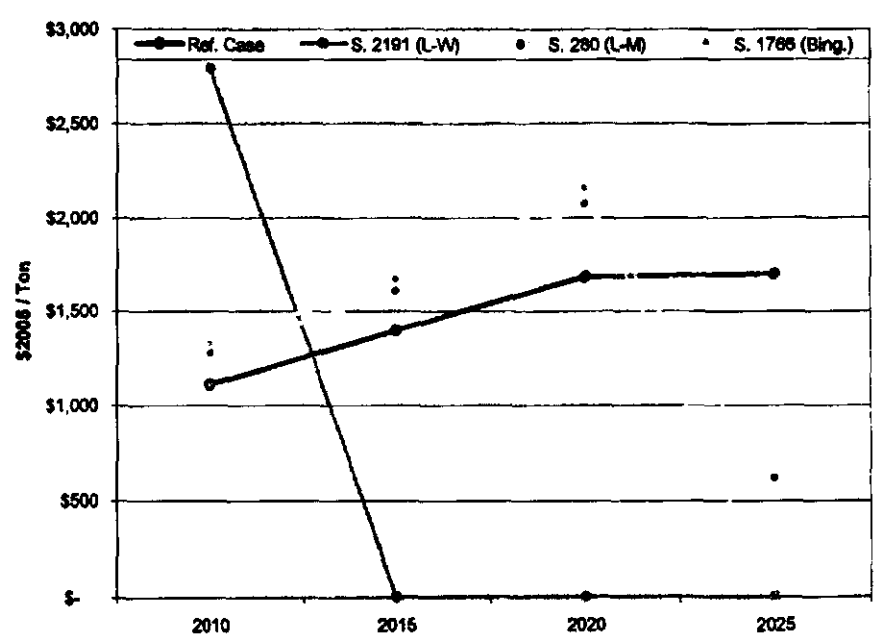
Note: Emissions generally reflect emissions from affected sources (Acid Rain Program and CAIR), which includes emissions from sources greater than 25 MW in capacity.

FMPA-POD1-00097

HEARING EXHIBIT - 00000260

SO_2 and NOx Allowance Price Comparisons (IPM)





- SO_2 allowance prices are for CAIR affected sources on a $/ton of emissions basis; Title IV allowance prices are not shown separately, but would be a fraction of this amount.
- S. 2191 has an influence on the allowance prices under existing and future cap and trade programs for SO_2 and NOx (the Acid Rain Program and CAIR).
- Generally, any allowance price for CO_2 creates downward pressure on SO_2 markets, and this pressure is amplified with higher CO_2 allowance prices. *For NOx, CO_2 allowance prices lead to shorter term price rises in NOx markets as sources rely on less capital-intensive control options for NOx (which are more expensive on the margin, hence the increased allowance price in earlier years), knowing that the higher CO_2 allowance prices in future years will result in lower NOx emissions as an ancillary effect (the NOx market essentially collapses under S. 2191).*
- Under S. 2191, there is a large amount of incremental coal retirements in 2025 as the allowance price hits $50/ton. In response, a considerable amount of new nuclear and renewables capacity is built along with new coal with CCS (although not nearly as much coal capacity as is retired) and thus, demand for SO_2 allowances goes down, leading to a kink in 2025.

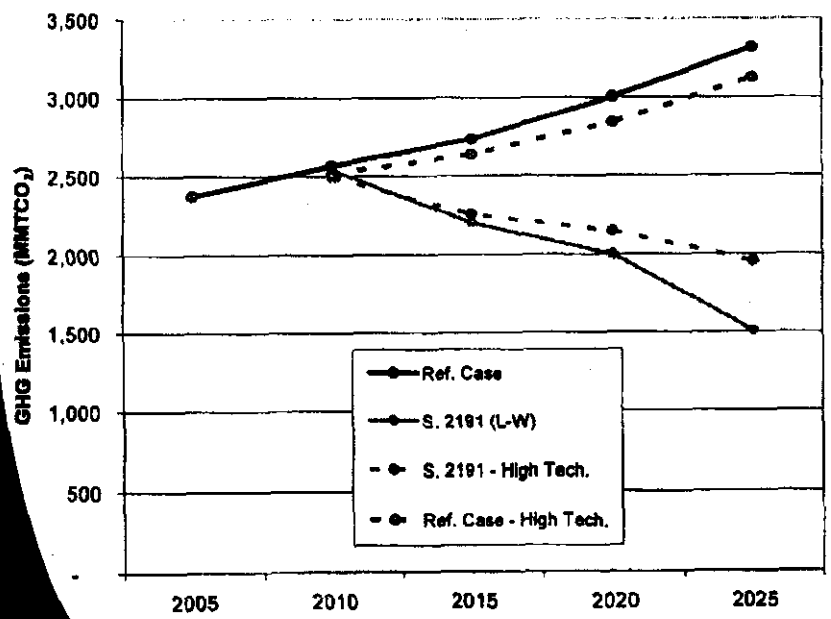
FMPA-POD1-00098

HEARING EXHIBIT - 00000261

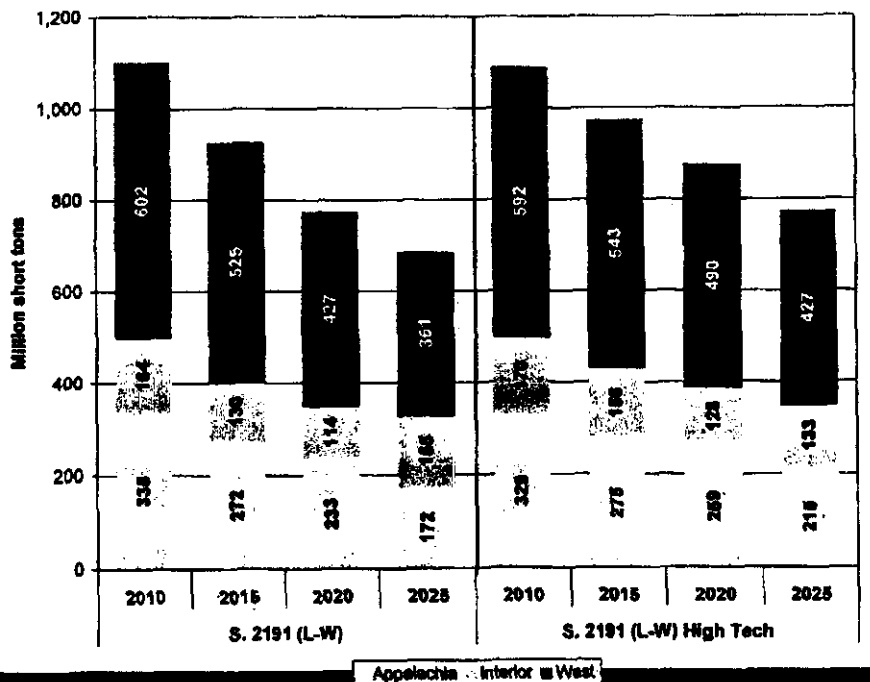
S. 2191 – High Technology Scenario (IPM)

- The high technology scenario is likely to be more similar to EIA's new AEO 2008 with the Energy Bill.
- Power sector CO_2 emissions in the high technology reference scenario are lower than the reference case because of lower electric demand and overall electricity generation. Under the S. 2191 high technology scenario, allowance prices are lower, resulting in greater reliance on coal generation and thus fewer CO_2 reductions compared to the primary S. 2191 case.

Power Sector CO_2 Emissions



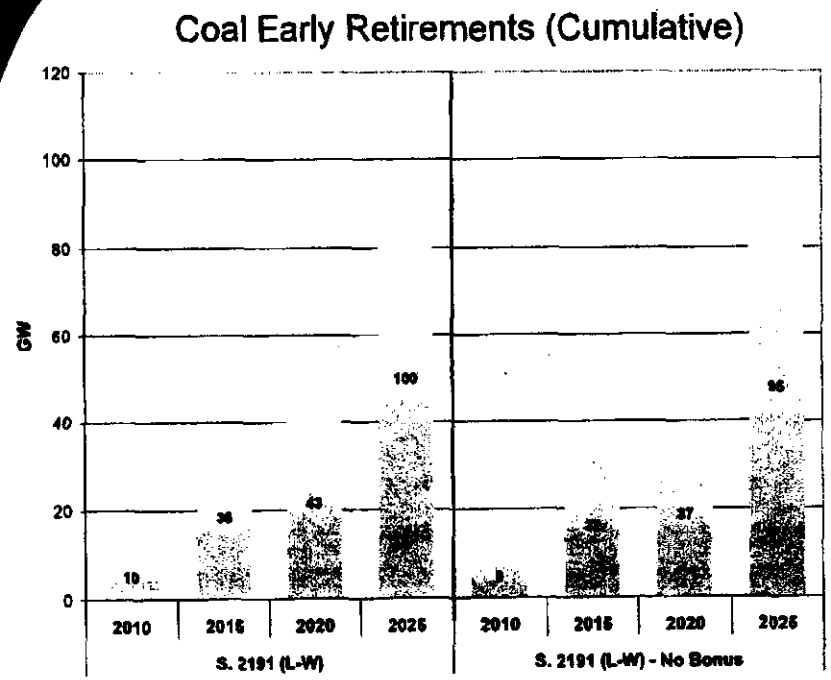
Coal Production for Electricity Generation

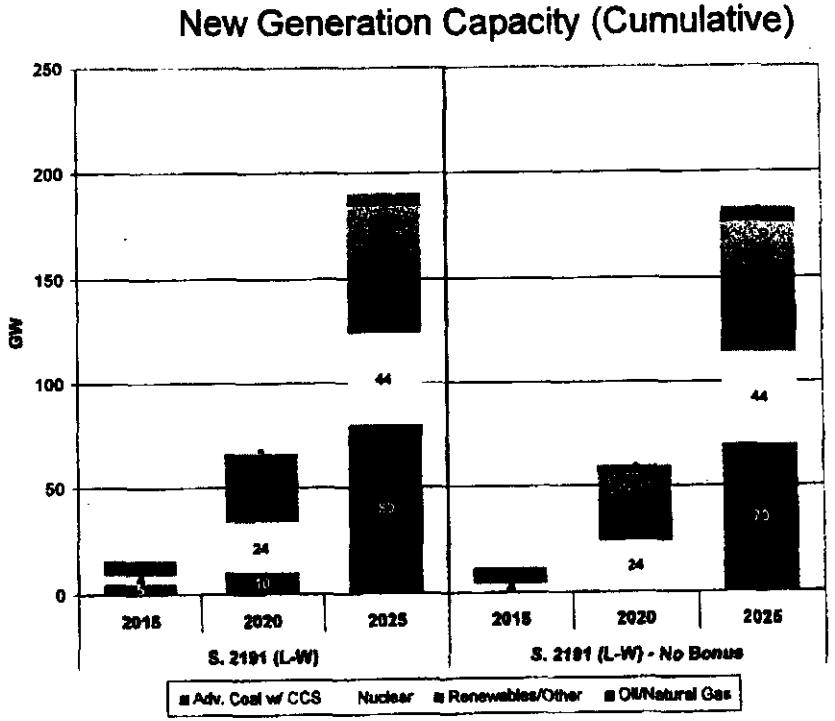


FMPA-POD1-00099

HEARING EXHIBIT - 00000262

S. 2191 With and Without CCS Bonus Allowances (IPM)





- Slightly fewer coal early retirements occur without the bonus in place, which acts as a subsidy and leads to the building of more CCS than otherwise would have been built.
- Advanced coal with CCS is built under S. 2191 even without the bonus (although later and a slightly lower amount).

FMPA-POD1-00100

HEARING EXHIBIT - 00000263

IPM Modeling Limitations

- IPM model timeframe only goes through 2025.
  - Model does not see longer term changes in electricity demand and CO_2 allowance prices (due to lowering of the cap post-2025).
  - This can affect projections for new capacity additions and retrofit decisions in later years.
- EPA's Base Case v3.01 does not incorporate several technological innovations that can become available over time (e.g., ultra-supercritical coal, advanced renewables).
- The recent labor/material shortfalls on future construction prices and the timing of power system adjustments have not been modeled.
- Geographic deployment, cost and performance of CCS is highly uncertain.
- Allowance allocation and auctioning are not fully accounted for in the modeling.
- While IPM endogenously builds new capacity, the model places an exogenous constraint on the total amount of new capacity builds.
  - The assumed limitations on new nuclear capacity reflect the recent EPRI analysis "The Power to Reduce CO_2 Emissions: The Full Portfolio" (August 2007) (http://epri-reports.org/DiscussionPaper2007.pdf)
  - There are non-economic considerations for significant expansion of nuclear power capacity which are not reflected in IPM.

FMPA-POD1-00101

HEARING EXHIBIT - 00000264

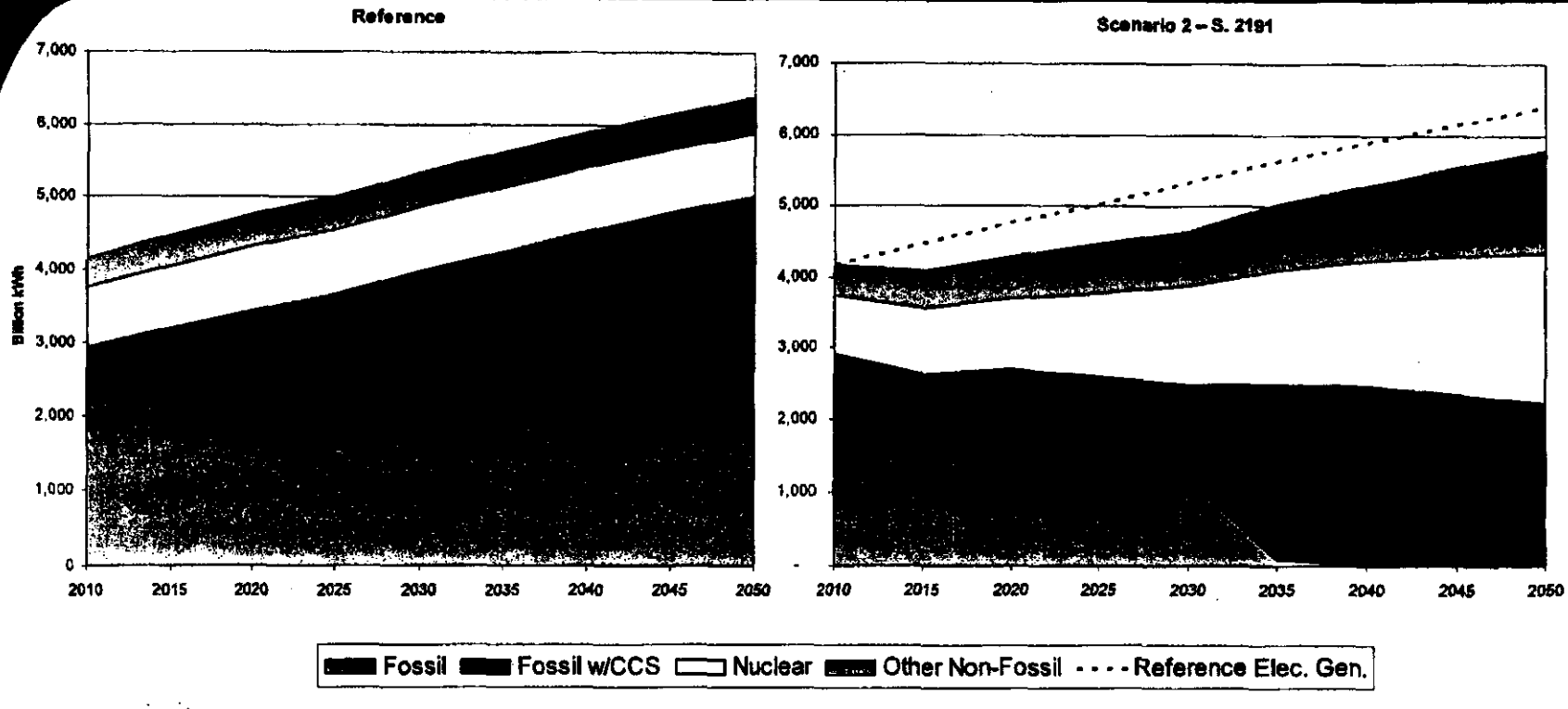
Energy Sector Modeling Results from Economy-wide Modeling

FMPA-POD1-00102

HEARING EXHIBIT - 00000265

Results: Scenario 1 – Reference; Scenario 2 – S. 2191

U.S. Electricity Generation, mid-term results (ADAGE)



- Under S. 2191, both nuclear and renewable electricity generation expands above the reference levels.
- In addition, CCS deployment on fossil-fuel generation begins after 2015. By 2030, 175 GW of new CCS capacity is projected to be built, which is the equivalent of 318 CCS units of 550 MW each. By 2050, 299 GW of new CCS capacity is projected to be built, which is the equivalent of 543 CCS units 550 MW each.
- By 2035, almost all fossil electricity generation is capturing and storing CO_2 emissions. (Note that because ADAGE does not represent peak versus base load generation requirements, the use of CCS technology on almost all fossil fuel generation by 2035 may be overly optimistic).

Note: Other non-fossil includes hydro, geothermal, wind, solar, biomass and municipal solid waste.

FMPA-POD1-00103

HEARING EXHIBIT - 00000266

Electricity Generation with CCS (ADAGE)

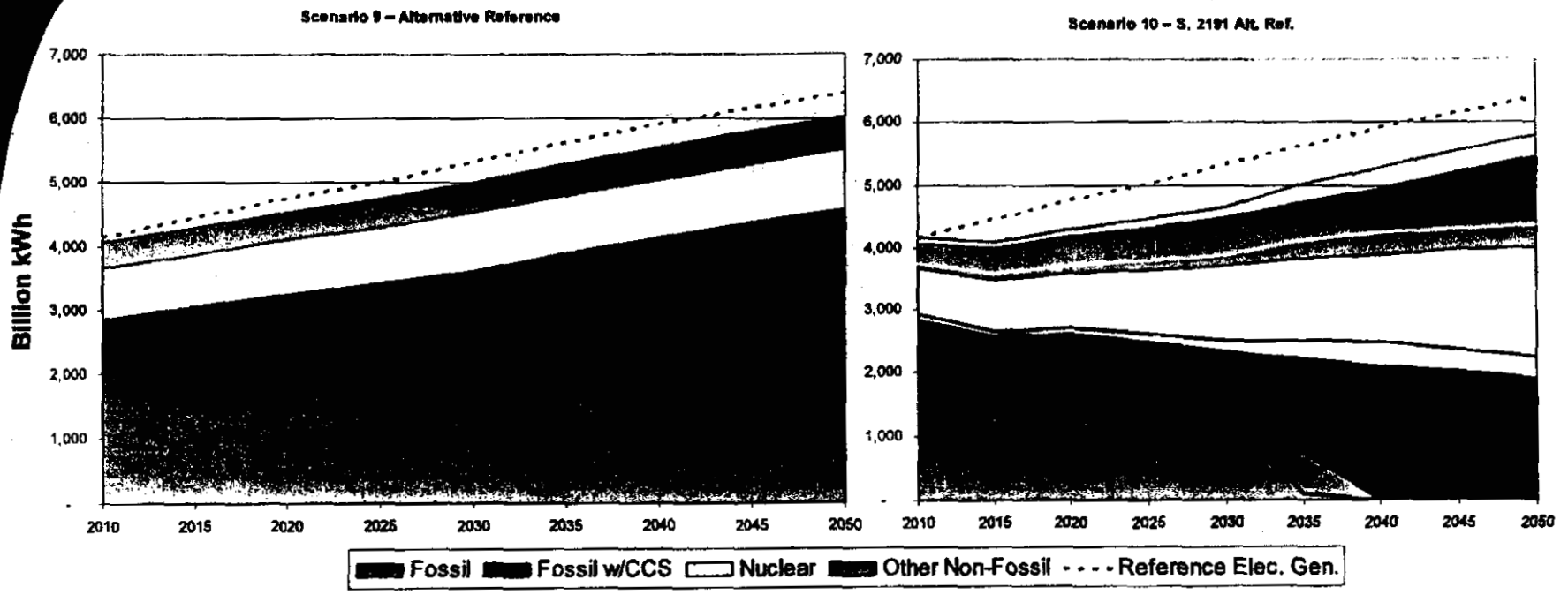
- As noted previously, large-scale availability of CCS technology is a key uncertainty in the analysis.
- ADAGE uses EIA data on CCS technology costs and effectiveness (*Assumptions to the Annual Energy Outlook*). Costs are also influenced by fuel prices and any bonus allowances received.
- Maximum penetration rates for CCS in each time period are based on a "learning-by-doing" structure, in which construction in previous years influences future capacity:
  - economic considerations control when CCS initially becomes cost effective in the model.
  - feasible capacity is initially generally based on construction rates for related technologies from AEO forecasts.
  - construction in future years is then controlled by the influence of past decisions on the existing technology base.

FMPA-POD1-00104

HEARING EXHIBIT - 00000267

Results: Scenario 9 – Alternative Reference; Scenario 10 – S. 2191 Alternative Reference

U.S. Electricity Generation, mid-term results (ADAGE)



- Under the assumptions of the Alternative Reference Scenario, the economy is more energy efficient and there is lower electricity demand .
- The emissions goals of S. 2191 are achieved with less alteration of the energy infrastructure.
- Electricity demand decreases; nuclear and non-fossil generation increases; but traditional fossil generation continues to be economic for longer in the Alternative case.

Note: Other non-fossil includes hydro, geothermal, wind, solar, biomass and municipal solid waste.

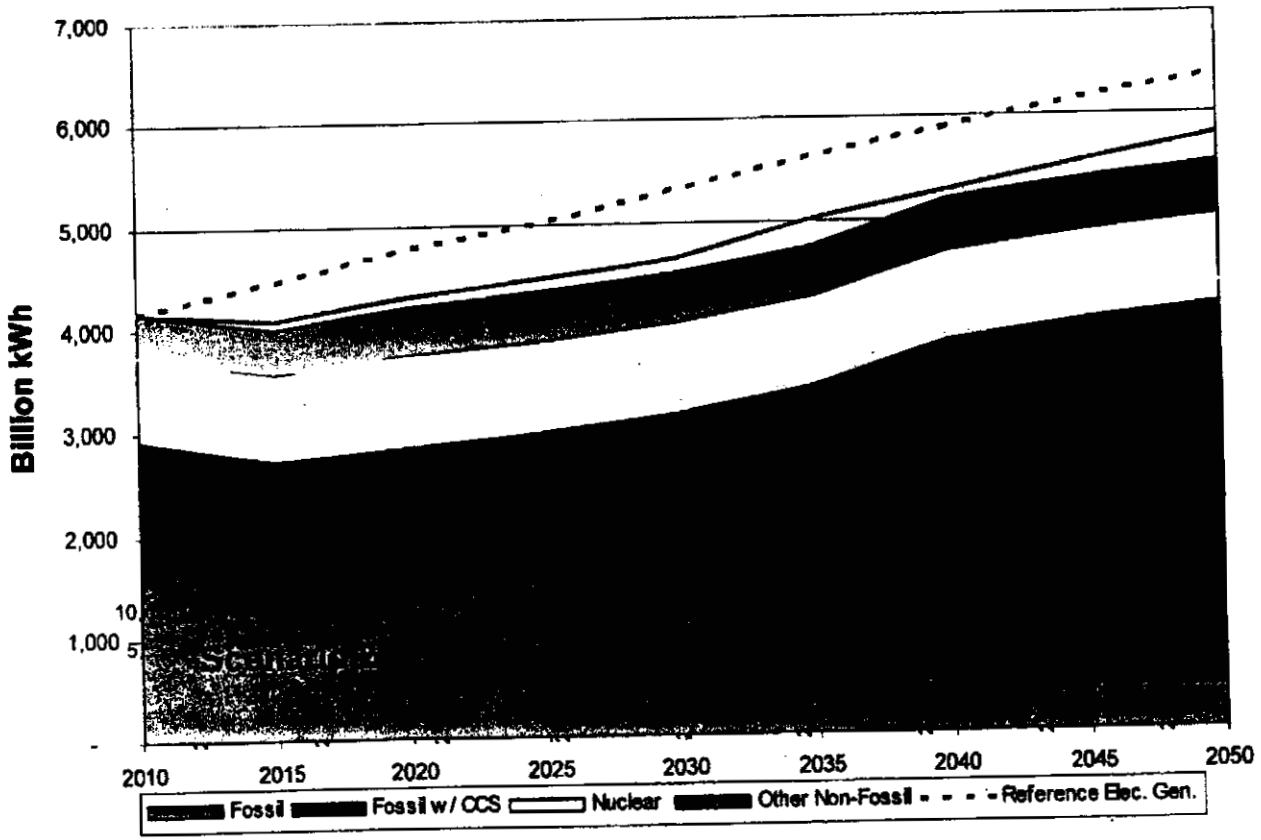
FMPA-POD1-00105

HEARING EXHIBIT - 00000268

Results: Scenario 6 – S. 2191, Constrained Nuclear & Biomass

U.S. Electricity Generation, mid-term results (ADAGE)

Scenario 6 – S. 2191 Constrained Nuclear & Biomass



- If nuclear and biomass generation do not grow in response to policy, carbon capture and storage technologies become the dominant source of generation.
- Electricity demand is reduced from the S. 2191 Scenario.
- Traditional fossil continues to be economic for longer than under the S. 2191 Scenario, as CCS reaches it's maximum penetration rate, and nuclear and biomass are not allowed to compete.

Note: Other non-fossil includes hydro, geothermal, wind, solar, biomass and municipal solid waste.

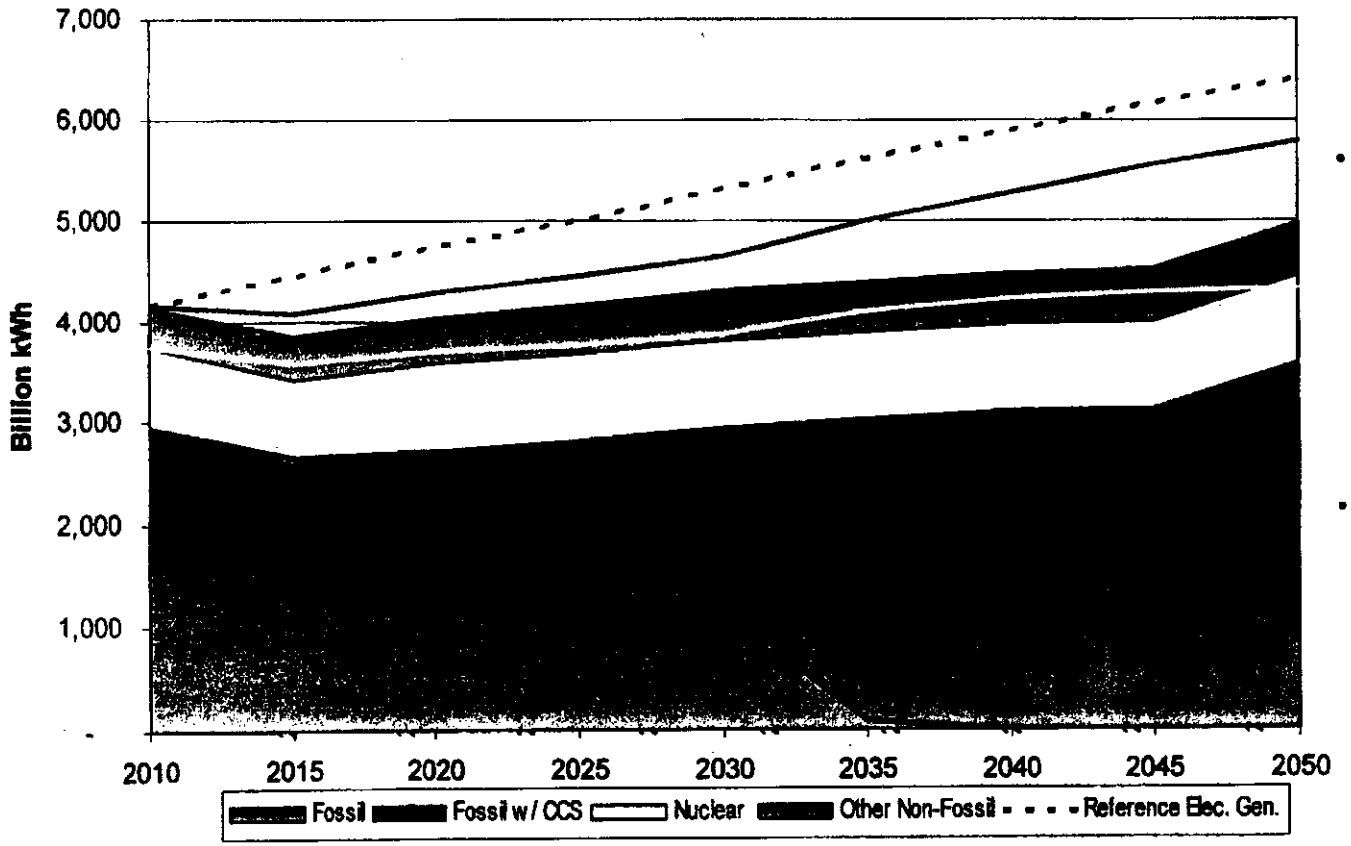
FMPA-POD1-00106

HEARING EXHIBIT - 00000269

Results: Scenario 7 – S. 2191, Constrained Nuclear & Biomass, and CCS

U.S. Electricity Generation, mid-term results (ADAGE)

Scenario 7 – S. 2191 Constrained Nuclear & Biomass, and CCS



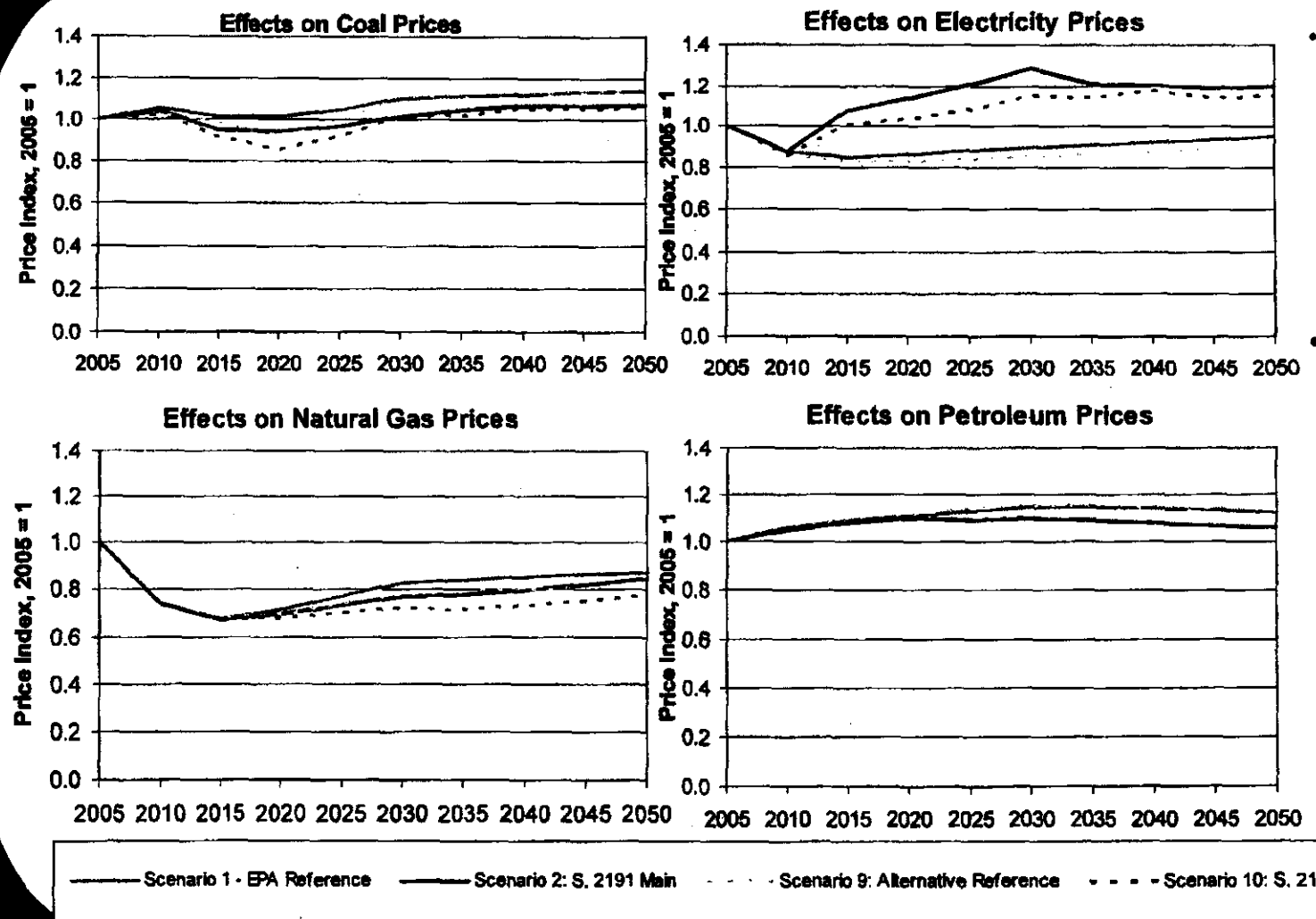
- If nuclear and biomass generation do not grow in response to policy, and carbon capture and storage technologies are not available before 2030, then demand for electricity is much lower than the S. 2191 Scenario.
- CCS technology reaches its maximum penetration rate, but traditional fossil generation is still supplying electricity by 2050.

Note: Other non-fossil includes hydro, geothermal, wind, solar, biomass and municipal solid waste.

FMPA-POD1-00107

HEARING EXHIBIT - 00000270

Results: Scenario 1 – Reference; Scenario 2 – S. 2191; Scenario 9 – Alternative Reference; Scenario 10 – S. 2191 Alt. Ref.
Fuel Prices (ADAGE)

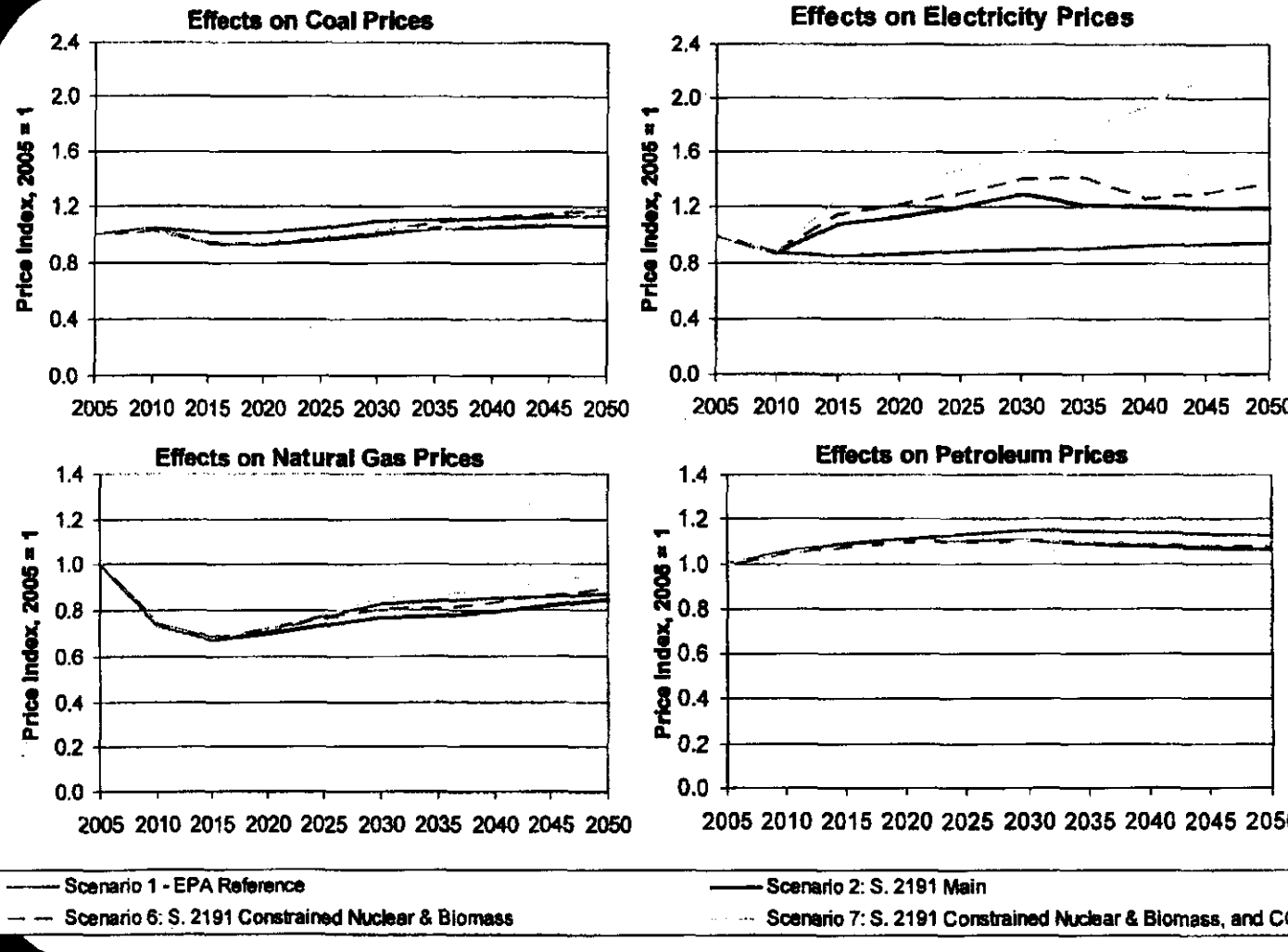


- Coal, natural gas, and oil prices are producer prices, and thus do not reflect the cost of allowances
- Electricity prices do reflect the cost of allowances

FMPA-POD1-00108

HEARING EXHIBIT - 00000271

Results: Scenario 1 – Reference; Scenario 2 – S. 2191; Scenario 6 – S. 2191 Constrained Nuclear & Biomass; Scenario 7 – S. 2191 Constrained Nuclear & Biomass, and CCS
Fuel Prices (ADAGE)



- Coal, natural gas, and oil prices are producer prices, and thus do not reflect the cost of allowances
- Electricity prices do reflect the cost of allowances

EMPA-POD1-00109
HEARING EXHIBIT - 00000272

Fuel Prices (ADAGE)

- The S. 2191 electricity price reflects the full allowance price the consumer would face.
- S. 2191 electricity prices are 44% higher than in the Reference Scenario in 2030 and 26% higher in 2050, reflecting a shift in fuel mix from coal to gas in the earlier years, the adoption of carbon capture and storage technology in later years, and the increased prices the consumers of coal and gas face due to the price of allowances.
  - Note that capital is more mobile in ADAGE than in IPM and agents in the model have perfect foresight, so the electricity sector responds immediately in the model to the high future allowance prices, this can result in a larger near term increase in the price of electricity in ADAGE than would be shown in IPM.
- Under the Alternative Reference Scenario energy prices are generally lower, due to reduced demand, compared to the reference scenario. Electricity prices in the S. 2191 case under alternative reference assumptions are 35% higher in 2030 and 28% higher in 2050 than the Alternative Reference Scenario prices.
- With assumptions that limit the growth of nuclear, biomass, or carbon capture and storage technologies, meeting the cap becomes more expensive, resulting in larger reductions in demand and increases in the costs of traditional fossil fuels as generators must purchase additional allowances. If all three technologies are constrained, electricity prices in 2030 are 79% higher and 2050 prices are 98% higher than the reference scenario prices.
- For coal, natural gas, and petroleum, the price effect of S. 2191 before adding in the allowance price is shown. This is the price producers of these fuels would face. Electricity prices do include the cost of holding allowances
- Lower demand for fossil fuel drives coal, petroleum and natural gas prices lower than in the Reference Scenario.
  - The impact of S. 2191 on petroleum prices is smaller than the impact on coal and natural gas prices, because fewer options exist in the transportation sector for substituting away from petroleum.
  - Natural gas prices fall further than coal prices, because advanced coal with CCS drives out natural gas fired generation in the electricity sector.
  - In 'Scenario 7 – S. 2191, Constrained Nuclear, Biomass, and CCS' natural gas prices increase, since fuel switching from coal to natural gas is the primary remaining option for the electricity sector to reduce emissions.

FMPA-POD1-00110

HEARING EXHIBIT - 00000273

Results: Scenario 2 - S. 2191

Fuel Price Adders for 2030 (ADAGE)

		2030		
	2005 Price	Producer Price	Cost of Carbon Content	End - User Price
Metric Ton of CO_2	n/a		$60.62	
Metric Ton of Carbon	n/a		$222.29	
Barrel of Oil	$50.28	$55.35	$25.95	$81.30
Gallon of Gasoline	$2.34	$2.58	$0.53	$3.11
Short Ton of Coal	$36.79	$37.24	$134.01	$171.25
Short Ton of Coal w/ CCS	$36.79	$37.24	$13.40	$50.64
tCf of Natural Gas	$7.51	$5.79	$3.30	$9.09

- The 2030 producer price is obtained by multiplying the 2030 index price in ADAGE by the 2005 price from EIA's 2006 Monthly Energy Review.
- The cost of carbon content is simply the product of the physical carbon content of the fuel and the allowance price.
- The end-user price is simply the sum of the producer price and the cost of carbon content.
- CCS technology for coal fired power generation captures and stores 90% of carbon emissions, which lowers the cost of carbon content by 90%, and lowers the consumer price accordingly.
- The cost of the carbon content increases the price of gasoline by 21%, increases the price of oil by 47%, increases the price of natural gas by 57%, increases the price of coal by 360%, and increases the price of coal used with CCS by 36%.
- Bonus allowances for CCS are not considered here.

FMPA-POD1-00111

HEARING EXHIBIT - 00000274

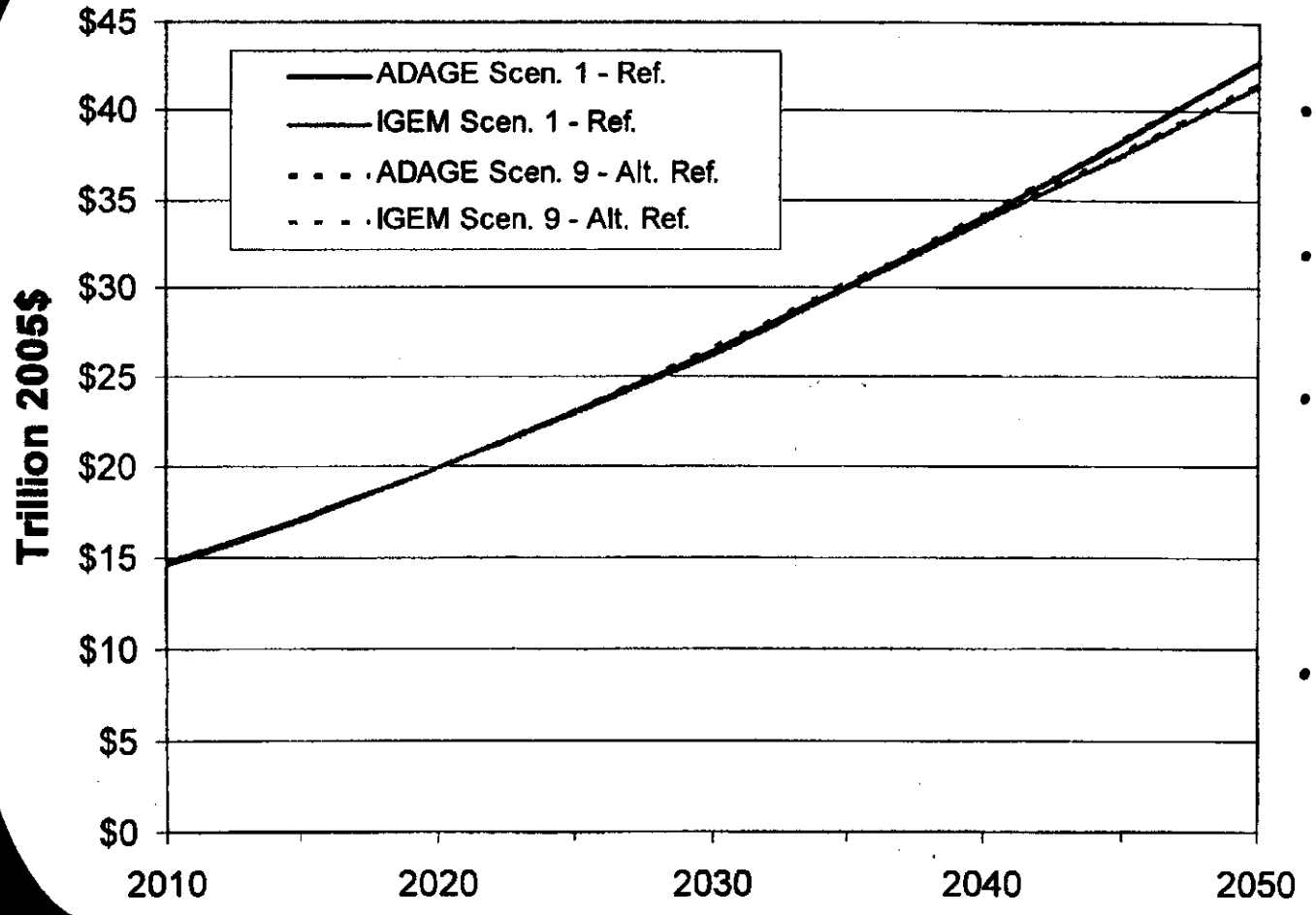
Economy-Wide and Sectoral Modeling Results

FMPA-POD1-00112

HEARING EXHIBIT - 00000275

Results: Scenario 1 - Reference and Scenario 9 – Alternative Reference

GDP



- GDP growth to 2030 is benchmarked to AEO2006
- Average annual GDP growth from 2010 to 2030 is ~2%.
- Differences in GDP growth in the later years are due to differences in underlying model assumptions
- GDP in the Alternative Reference Scenario is slightly higher than the Reference Scenario

FMPA-POD1-00113

HEARING EXHIBIT - 00000276

Results: Comparing Scenario 2 – S. 2191 with Scenario 10 – S. 2191 Alternative Reference

GDP (Billion 2005$)

Reference Scenario vs. S.2191 Scenario

	2010	2020	2030	2040	2050	Average Annual Growth 2010-2050
Scenario 1 - EPA Reference						
ADAGE	$14,620	$19,620	$26,458	$33,958	$42,696	2.72%
IGEM	$14,733	$19,851	$26,173	$33,716	$41,372	2.61%
Scenario 2 - S.2191						
ADAGE	$14,593	$19,483	$26,200	$33,470	$41,684	2.66%
IGEM	$14,595	$19,345	$25,190	$31,964	$38,516	2.46%
Absolute Change						
ADAGE	-$27	-$137	-$258	-$488	-$1,012	*-0.06 Percentage Points*
IGEM	-$138	-$506	-$983	-$1,752	-$2,856	*-0.16 Percentage Points*
% Change						
ADAGE	-0.18%	-0.69%	-0.90%	-1.44%	-2.37%	
IGEM	-0.94%	-2.55%	-3.76%	-5.20%	-6.90%	

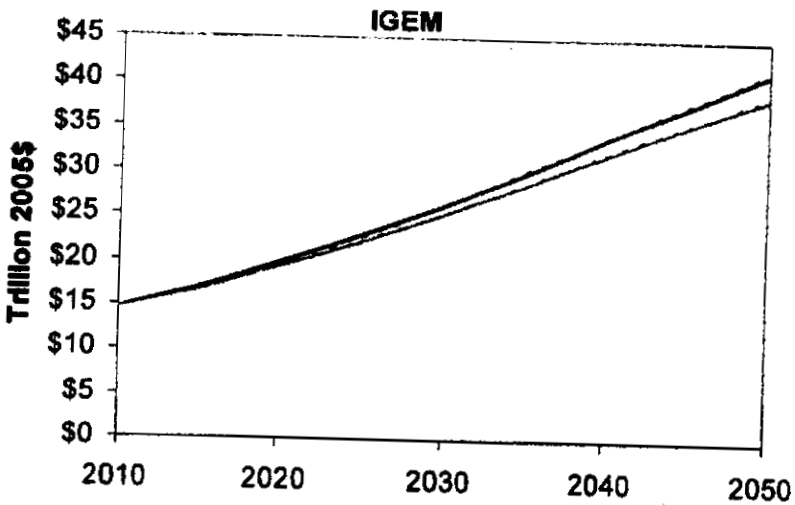
Alternative Reference Scenario vs. S.2191 Alt. Ref. Scenario

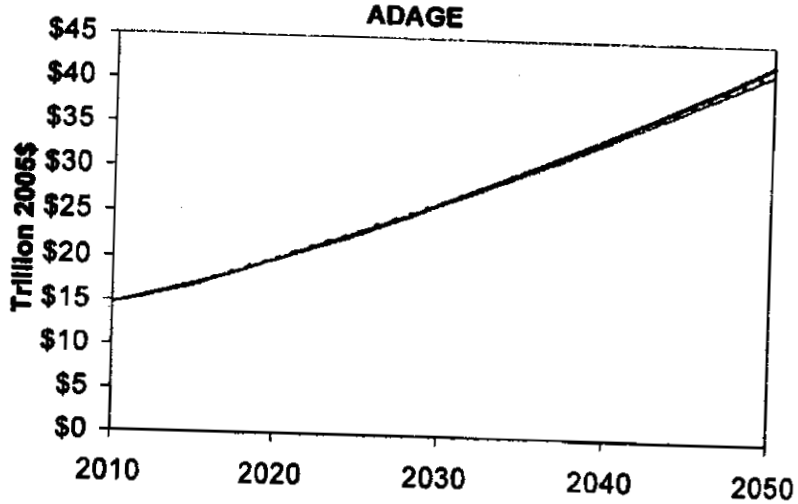
	2010	2020	2030	2040	2050	Average Annual Growth 2010-2050
Scenario 9 - Alternative Reference Scenario						
ADAGE	$14,638	$19,673	$26,509	$34,019	$42,747	2.72%
IGEM	$14,698	$19,802	$26,220	$33,803	$41,478	2.63%
Scenario 10 - S.2191 Alt. Ref.						
ADAGE	$14,619	$19,775	$26,351	$33,666	$41,993	2.67%
IGEM	$14,602	$19,385	$25,274	$32,103	$38,731	2.47%
Absolute Change						
ADAGE	-$20	-$99	-$158	-$353	-$754	*-0.04 Percentage Points*
IGEM	-$95	-$417	-$947	-$1,700	-$2,747	*-0.16 Percentage Points*
% Change						
ADAGE	-0.13%	-0.50%	-0.60%	-1.04%	-1.76%	
IGEM	-0.65%	-2.10%	-3.61%	-5.03%	-6.62%	

FMPA-POD1-00114

HEARING EXHIBIT - 00000277

Results: Scenario 2 – S. 2191; and Scenario 10 – S. 2191 Alternative Reference GDP





Scenario 1 - EPA Reference
Scenario 2 - S.2191
Scenario 9 - Alternative Reference
Scenario 10 - S.2191 Alt. Ref.

Scenario 2 - S. 2191

IGEM

	2010	2020	2030	2040	2050
Absolute Change	-$138	-$506	[illegible]	[illegible]	[illegible]
% Change	-0.94%	-2.55%	-3.76%	-5.20%	-6.90%

ADAGE

	2010	2020	2030	2040	2050
Absolute Change	[illegible]	[illegible]	[illegible]	[illegible]	-$1,012
% Change	-0.18%	-0.69%	-0.90%	-1.44%	-2.37%

Scenario 10 - S. 2191 High Technology

	2010	2020	2030	2040	2050
Absolute Change	-$95	-$417	-$947	-$1,706	-$2,747
% Change	-0.65%	-2.10%	-3.81%	-5.03%	-6.62%

	2010	2020	2030	2040	2050
Absolute Change	-$20	-$99	-$158	-$353	-$754
% Change	-0.13%	-0.50%	-0.60%	-1.04%	-1.76%

FMPA-POD1-00115
HEARING EXHIBIT - 00000278

Results: Scenario 2 – S. 2191 and Scenario 10 – S. 2191 Alternative Reference GDP

- The structure of the IGEM model tends to lead to larger GDP impacts for a given allowance price than the ADAGE model.
  - The elasticity of a household's choice between demand for leisure and demand for goods and services is one of the most important differences between the models that results in the difference in GDP effects (Jorgenson et al. 2000). In ADAGE, this consumption-leisure parameter is adopted from values of related parameters in the empirical literature, while in IGEM this parameter is estimated from historical data. While both models assume that the compensated labor supply elasticity is inelastic, the value used in IGEM is relatively more elastic than the value used in ADAGE. The result of this difference is that similar allowance prices in the two models, result in larger changes in household behavior in IGEM, and thus larger overall economic impacts.
- Additionally, the several other factors lead to a larger difference in GDP impacts than might otherwise be expected.
  - Representation of international GHG policies
    - Since IGEM is a domestic model, world prices are not affected by climate policies in Group 1 and Group 2 countries. As a result of S. 2191, the prices of U.S. exports rise relative to prices in the rest of the world, and export volumes fall. Since exports are price-elastic the volumes fall proportionally more than the price rises and thus the value of exports declines. Imports are reduced in part by the overall reduction in spending associated with the lower levels of consumption. Additionally, commodities directly affected by the emissions cap (e.g. oil) are reduced proportionally more than other imports due to the allowance prices embodied in their cost. Import substitution counterbalances the two forces above. U.S. prices of commodities not directly affected by the policy are relatively higher, which leads to substitution away from domestically produced goods and towards imported goods. To the extent that policies in Group 1 and Group 2 countries increase world prices of affected commodities, the relative price difference between goods produced in the U.S. and goods produced abroad will be lessened. This will reduce impact on exports, and reduce the import substitution effect, both of which are driven by the relative price differential, and subsequently reduce the impact on GDP.
  - Reference case emissions
    - The higher reference case total and covered GHG emissions in IGEM compared to ADAGE lead to higher allowance prices, which in turn lead to higher GDP impacts.
- The GDP impacts found by other models that have analyzed S. 2191 (e.g. MIT* and CRA**) tend to be closer to GDP impacts in ADAGE than GDP impacts in IGEM.
- Changes in consumption may be a better measure of the costs of S. 2191 than changes in GDP since utility (and thus welfare) is a direct function of consumption and not GDP.

* Paltsev et al., "Assessment of U.S. Cap-and-Trade Proposals – Appendix D: Analysis of the Cap and Trade Features of the Lieberman-Warner Climate Security Act (S. 2191)" 2007.

** CRA International, "Economic Modeling of the Lieberman-Warner Bill: S. 2191 as Reported by Senate EPW," January 2008.

FMPA-POD1-00116

HEARING EXHIBIT - 00000279

Scenario Comparison

GDP Impacts

(Percentage Change from Reference)

Table: GDP Comparisons (% Change from Reference)

	2015	2020	2025	2030	2035	2040	2045	2050
1) EPA Reference								
ADAGE	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2) S. 2191								
ADAGE	-0.7%	-0.7%	-0.7%	-0.9%	-1.1%	-1.4%	-1.9%	-2.4%
IGEM	-2.0%	-2.6%	-3.1%	-3.8%	-4.4%	-5.2%	-6.0%	-6.9%
3) S. 2191 with Low International Actions								
ADAGE	-0.8%	-0.9%	-0.9%	-1.2%	-1.3%	-1.6%	-2.0%	-2.5%
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
4) S. 2191 Unlimited Offsets								
ADAGE	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
IGEM	-0.7%	-0.9%	-1.1%	-1.3%	-1.6%	-1.9%	-2.3%	-2.7%
5) S. 2191 No Offsets								
ADAGE	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
IGEM	-3.3%	-4.1%	-5.0%	-5.9%	-6.9%	-7.9%	-9.0%	-10.1%
6) S. 2191 Constrained Nuclear & Biomass								
ADAGE	-0.8%	-0.9%	-0.9%	-1.2%	-1.6%	-2.0%	-2.6%	-3.3%
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
7) S. 2191 Constrained Nuclear & Biomass, and CCS								
ADAGE	-1.1%	-1.5%	-1.8%	-2.3%	-2.6%	-3.1%	-3.8%	-4.4%
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
8) S. 2191 Constrained Nuclear & Biomass + Beyond Kyoto + Natural Gas Cartel								
ADAGE	-1.1%	-1.4%	-1.6%	-2.1%	-2.4%	-2.9%	-3.6%	-4.3%
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
9) Alternative Reference								
ADAGE	0.1%	0.3%	0.3%	0.3%	0.2%	0.2%	0.1%	0.1%
IGEM	0.3%	0.2%	0.1%	-0.2%	-0.2%	-0.3%	-0.3%	-0.3%
10) S. 2191 Alternative Reference								
ADAGE	-0.3%	-0.2%	-0.2%	-0.3%	-0.5%	-0.9%	-1.2%	-1.6%
IGEM	-1.5%	-2.1%	-2.8%	-3.6%	-4.3%	-5.0%	-5.8%	-6.8%

FMPA-POD1-00117

HEARING EXHIBIT - 00000280

Results: Scenario 2 – S. 2191; and Scenario 10 – S. 2191 Alternative Reference

Consumption (Billion 2005$)

Table: Impact of S. 2191 on U.S. Consumption (Billion 2005 Dollars)

	2010	2020	2030	2040	2050	Average Annual Growth 2010-2050
Scenario 1 - EPA Reference						
ADAGE	$10,783	$14,638	$19,721	$25,550	$31,887	2.75%
IGEM	$9,222	$12,348	$16,231	$20,921	$25,838	2.61%
Scenario 2 - S.2191						
ADAGE	$10,858	$14,676	$19,641	$25,387	$31,217	2.68%
IGEM	$9,259	$12,265	$15,998	$20,443	$24,995	2.51%
Absolute Change						
ADAGE	$75	$38	-$80	-$163	-$670	*-0.07 Percentage Points*
IGEM	$36	-$82	-$233	-$478	-$843	*-0.10 Percentage Points*
% Change						
ADAGE	0.69%	-0.26%	-0.41%	-0.64%	-2.10%	
IGEM	0.39%	-0.66%	-1.44%	-2.28%	-3.26%	
Annual Change per Household (2005$)						
ADAGE	$574	$288	-$1,176	-$2,188	-$3,984	
IGEM	$300	-$608	-$1,574	-$2,943	-$4,771	

	2010	2020	2030	2040	2050	Average Annual Growth 2010-2050
Scenario 9 - Alternative Reference Scenario						
ADAGE	$10,797	$14,673	$19,760	$25,382	$31,914	2.75%
IGEM	$9,223	$12,338	$16,242	$20,968	$25,903	2.62%
Scenario 10 - S.2191 Alt. Ref.						
ADAGE	$10,859	$14,640	$19,643	$25,287	$31,372	2.69%
IGEM	$9,257	$12,277	$16,027	$20,497	$25,083	2.52%
Absolute Change						
ADAGE	$63	-$34	-$118	-$265	-$542	*-0.06 Percentage Points*
IGEM	$34	-$61	-$215	-$471	-$820	*-0.09 Percentage Points*
% Change						
ADAGE	0.58%	-0.23%	-0.60%	-1.04%	-1.70%	
IGEM	0.37%	-0.49%	-1.32%	-2.25%	-3.17%	

FMPA-POD1-00118
HEARING EXHIBIT - 00000281

Results: Scenario 2 – S. 2191; and Scenario 10 – S. 2191 Alternative Reference

Consumption

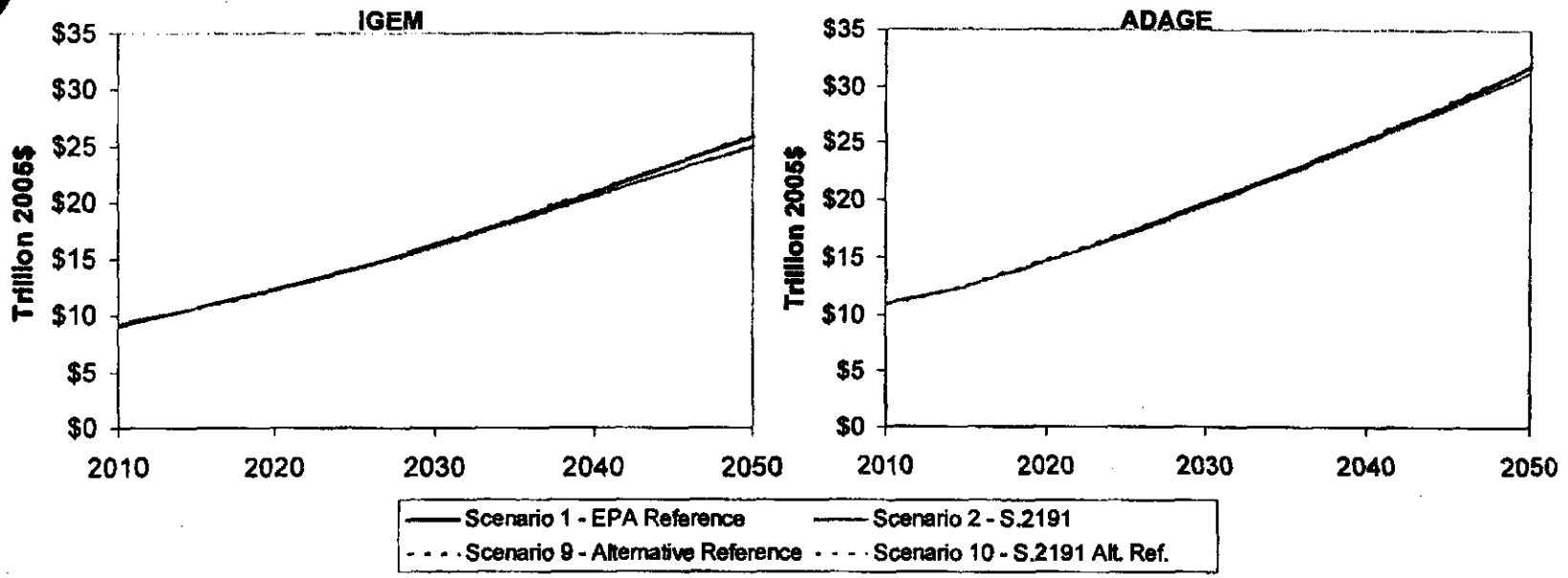


Table: **Impact of S. 2191 on U.S. Consumption (2005 Dollars)**

IGEM

	2010	2020	2030	2040	2050
Scenario 2 - S. 2191					
Annual Change / HH	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
% Change	0.39%	-0.66%	-1.44%	-2.26%	-3.26%
Scenario 10 - S.2191 Alt. Ref.					
Annual Change / HH	$281	-$454	-$1,[illegible]	-$2,[illegible]	-$4,[illegible]
% Change	0.37%	-0.49%	-1.32%	-2.25%	-3.17%

ADAGE

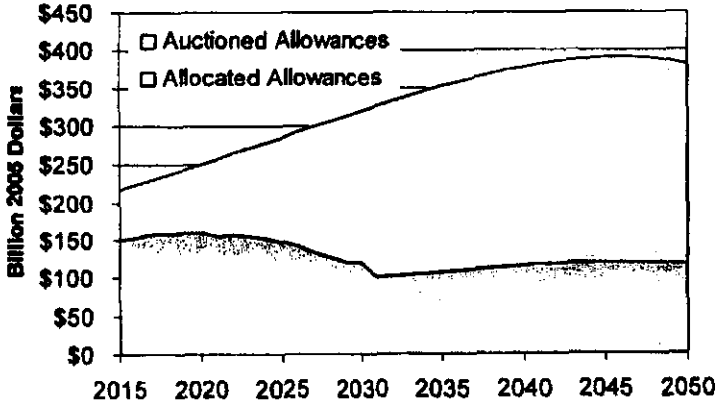
	2010	2020	2030	2040	2050
Scenario 2 - S. 2191					
Annual Change / HH	[illegible]	[illegible]	-$1,176	-$2,188	-$3,984
% Change	-0.69%	-0.43%	-0.91%	-1.39%	-2.10%
Scenario 10 - S.2191 Alt. Ref.					
Annual Change / HH	-$466	-$239	-$768	-$1,765	-$3,222
% Change	0.58%	-0.23%	-0.60%	-1.12%	-1.70%

FMPA-POD1-00119
HEARING EXHIBIT - 00000282

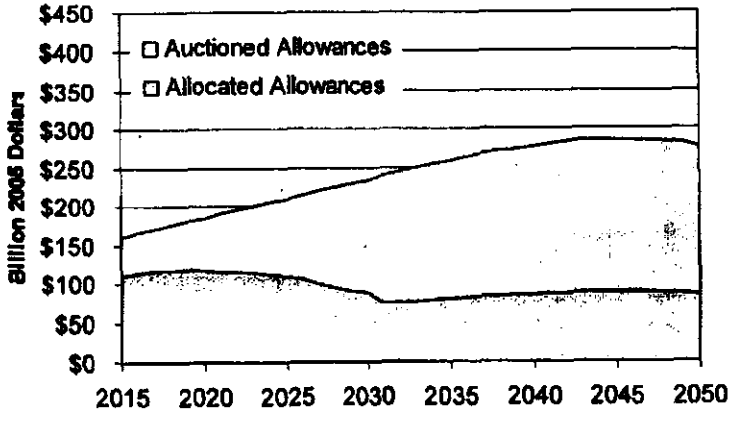
Results: Scenario 2 – S. 2191

Value of Allocated & Auctioned Allowances

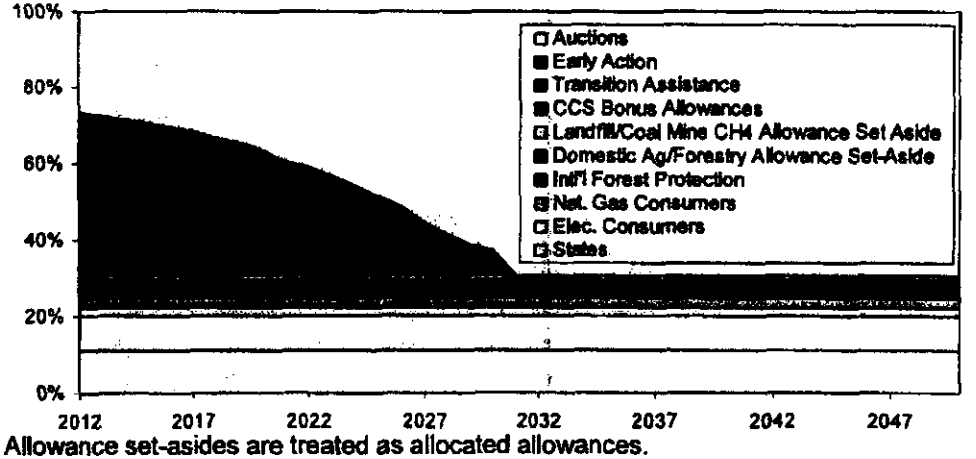
S. 2191 (IGEM)



S. 2191 (ADAGE)



- The share of allowances that are auctioned, allocated, or designated for set-aside programs is specified in S. 2191 *Title III – Allocating and Distributing Allowances.*



- Allowance set-asides are treated as allocated allowances.
- In IGEM we assume that the policy is deficit and revenue neutral, which implies that the market outcomes are invariant to the auction / allocation spilt
  - Private sector revenues from allocated allowances accrue to employee-shareholder households, and the government adjusts taxes lump sum to maintain deficit and spending levels.
  - Allowance auction revenues flow to the U.S. government, and are redistributed to households lump sum to the extent that deficit and spending levels are maintained. If auction revenues were directed to special funds instead of returned directly to households as modeled, the reduction in household annual consumption and GDP would likely be greater. If the auction revenues were instead used to lower distortionary taxes, the costs of the policy would be lower.
- In IPM the auction / allocation split affects market outcomes because regulated electric utilities, which are explicitly modeled, are allowed to pass on the cost of auctioned allowances to consumers, but are not allowed to pass on the cost of allocated allowances.

FMPA-POD1-00120
HEARING EXHIBIT - 00000283

Results: Scenario 2 – S. 2191

Value of Allocated & Auctioned Allowances

Table: Value of Auctioned and Allocated Allowances (Billion 2005 $)
S. 2191 Title III - Allocating and Distributing Allowances

	2015	2020	2025	2030	2035	2040	2045	2050
Subtitle A - Auctions								
ADAGE	$47	$87	$101	$147	$179	$191	$197	$192
IGEM	$64	$92	$139	$201	$245	$263	$272	$285
Subtitle B - Early Action								
ADAGE	$3	$0	$0	$0	$0	$0	$0	$0
IGEM	$4	$0	$0	$0	$0	$0	$0	$0
Subtitle C - States								
ADAGE	$18	$20	$23	$26	$28	$30	$31	$30
IGEM	$24	$28	$31	$35	$39	$42	$43	$42
Subtitle D - Electricity Consumers								
ADAGE	$14						$26	$25
IGEM	$20	$23	$26	$29	$32	$34	$35	$34
Subtitle E - Natural Gas Consumers								
ADAGE	$3						$6	$6
IGEM	$4	$5			$7	$8	$8	$8
Subtitle F - Bonus Allowances for CCS								
ADAGE	$6	$7				$0	$0	$0
IGEM	$9	$10	$11	$13	$0	$0	$0	$0
Subtitle G - Domestic Ag/Forestry								
ADAGE	$8	$9	$10	$12	$13	$14	$14	$14
IGEM	$11	$13	$14	$16	$18	$19	$20	$19
Subtitle H - International Forest Protection								
ADAGE	$4	$5	$5	$6	$6	$7	$7	$7
IGEM	$5	$6	$7	$8	$9	$9	$10	$10
Subtitle I - Transition Assistance								
ADAGE	$54	$53	$36	$6	$0	$0	$0	$0
IGEM	$74	$73	$49	$9	$0	$0	$0	$0
Subtitle J - Landfill / Coal Mine CH4 Allowance Set - Asides								
ADAGE	$2	$2	$2	$2	$3	$3	$3	$3
IGEM	$2	$3					$4	$4

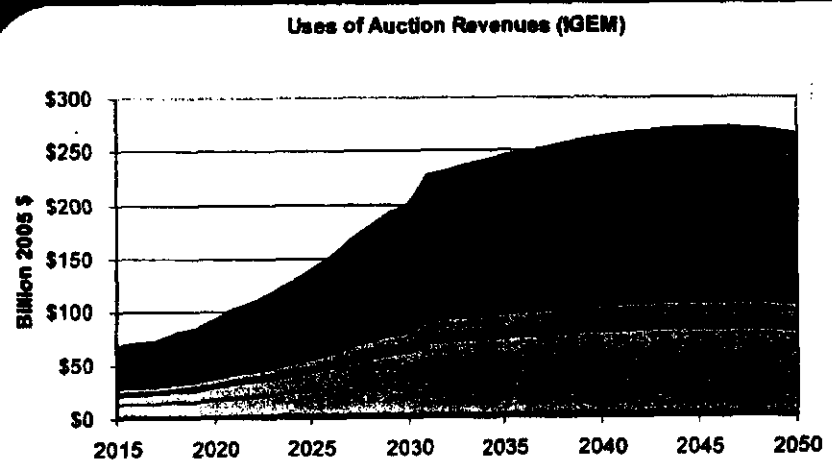
- The percentage of allowances to be allocated for each of these purposes is specified in S. 2191 Title III – Allocating and Distributing Allowances.
- While the values of all the uses of allocated and auctioned allowances are reported here; only the emissions reductions associated with the allowance set asides in *Subtitle G – Domestic Ag/Forestry* and *Subtitle J – Landfill / Coal Mine CH4 Allowance Set – Asides*; and the effect of the subsidy for carbon capture and sequestration technology specified in *Subtitle F – Bonus Allowances for CCS* are explicitly modeled.

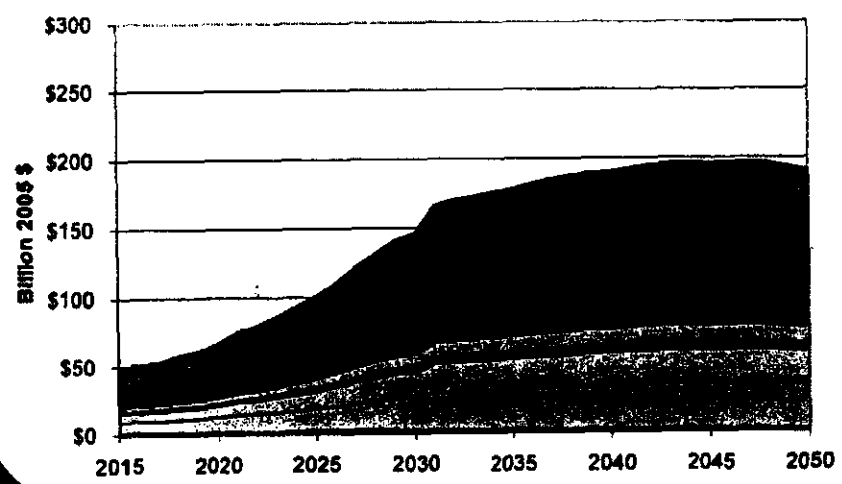
FMPA-POD1-00121

HEARING EXHIBIT - 00000284

Results: Scenario 2 – S. 2191

Value and Uses of Auctioned Allowances





- Energy Independence Acceleration Fund
- Emergency Firefighting Program
- International Climate Change Adaptation and National Security Program
- Adaptation for Natural Resources in the U.S. and Territories
- Climate Change Worker Training Program
- Sustainable Energy Program
- Advanced Technology Vehicles Manufacturing Program
- Fuel from Cellulosic Biomass Program
- Advanced Coal and Sequestration Technologies Program
- Zero or Low-Carbon Energy Technologies Deployment
- Administration of S. 2191 (assumed to be 1% or auction revenues)

- The percentage of auction revenues to be used for each of these purposes is specified in S. 2191 Title IV – Auctions and Uses of Auction Proceeds.
- While the values of all the uses of auctioned allowances are reported here, the programs specified are not explicitly modeled in this analysis.

FMPA-POD1-00122

HEARING EXHIBIT - 00000285

Results: Scenario 2 – S. 2191

Value and Uses of Auctioned Allowances

Table: Value and Uses of Auctioned Allowances (Billion 2005 $)

S. 2191 Title IV - Auctions and Uses of Auction Proceeds

	2015	2020	2025	2030	2035	2040	2045	2050
Administration of S. 2191 (assumed to be 1% or auction revenues)								
ADAGE	$1.6	$1.8	$2.0	$2.3	$2.6	$2.8	$2.8	$2.8
IGEM	$2.2	$2.5	$2.9	$3.2	$3.5	$3.8	$3.9	$3.8
Zero or Low-Carbon Energy Technologies Deployment								
ADAGE	$7.8	$10.8	$15.2	$23.7	$29.0	$31.0	$31.6	$31.0
IGEM	$10.9	$14.6	$22.4	$32.7	$40.0	$42.9	$44.3	$43.3
Advanced Coal and Sequestration Technologies Program								
ADAGE	$6.1	$8.3	$12.7	$18.5	$22.6	$24.2	$24.9	$24.3
IGEM	$8.5	$11.4	$17.5	$25.6	$31.2	$33.5	$34.6	$33.8
Fuel from Cellulosic Biomass Program								
ADAGE	$1.5	$2.0	$3.0	$4.4	$5.4	$5.8	$6.0	$5.8
IGEM	$2.0	$2.7	$4.2	$6.1	$7.5	$8.0	$8.3	$8.1
Advanced Technology Vehicles Manufacturing Program								
ADAGE	$2.9	$4.0	$6.1	$8.9	$10.9	$11.6	$12.0	$11.6
IGEM	$4.1	$5.5	$8.4	$12.3	$15.0	$16.1	$16.6	$16.2
Sustainable Energy Program								
ADAGE	$6.1	$8.3	$12.7	$18.5	$22.6	$24.2	$24.9	$24.3
IGEM	$8.5	$11.4	$17.5	$25.6	$31.2	$33.5	$34.6	$33.8
Energy Consumers								
ADAGE	$8.5	$11.4	$17.5	$25.6	$31.3	$33.5	$34.5	$33.6
IGEM	$11.7	$15.8	$24.2	$35.4	$43.2	$46.4	$48.0	$46.8
Climate Change Worker Training Program								
ADAGE	$2.4	$3.2	$4.9	$7.1	$8.7	$9.3	$9.6	$9.3
IGEM	$3.3	$4.4	$6.7	$9.8	$12.0	$12.9	$13.3	$13.0
Adaptation for Natural Resources in the U.S. and Territories								
ADAGE	$8.5	$11.4	$17.5	$25.6	$31.3	$33.5	$34.5	$33.6
IGEM	$11.7	$15.8	$24.2	$35.4	$43.2	$46.4	$48.0	$46.8
International Climate Change Adaptation and National Security Program								
ADAGE	$2.4	$3.2	$4.9	$7.1	$8.7	$9.3	$9.6	$9.3
IGEM	$3.3	$4.4	$6.7	$9.8	$12.0	$12.9	$13.3	$13.0
Emergency Firefighting Program								
ADAGE	$1.2	$1.2	$1.2	$1.2	$1.2	$1.2	$1.2	$1.2
IGEM	$1.2	$1.2	$1.2	$1.2	$1.2	$1.2	$1.2	$1.2
Energy Independence Acceleration Fund								
ADAGE	$6.8	$9.5	$14.0	$20.4	$25.9	$28.0	$28.8	$28.0
IGEM	$9.4	$12.7	$19.3	$28.2	$34.6	$37.1	$38.3	$37.4

- The percentage of auction revenues to be used for each of these purposes is specified in S. 2191 Title IV – Auctions and Uses of Auction Proceeds.
- While the values of all the uses of auctioned allowances are reported here, the programs specified are not explicitly modeled in this analysis.

FMPA-POD1-00123

HEARING EXHIBIT - 00000286

Results: Scenario 2 - S. 2191

2030 Selected Sectoral Results (IGEM)

Sector	2007	2030				
		Reference		S.2191 Scenario 2		
	Output ($Billions)	Output ($Billions)	Percent Change from 2007	Output ($Billions)	Percent Change from 2007	Percent Change from Reference
Personal and business services	4468	8419	88%	8367.2	87%	-1%
Finance, insurance and real estate	2743	6307	130%	6229.7	127%	-1%
Transportation and warehousing	707	1334	89%	1260.3	78%	-5%
Food and kindred products	587	1199	104%	1304.3	122%	9%
Motor vehicles	532	1137	114%	1060.0	99%	-7%
Electric utilities (services)	399	569	43%	460.2	15%	-19%
Petroleum refining	307	403	31%	296.5	-4%	-27%
Gas utilities (services)	52	63	20%	43.4	-17%	-31%
Coal mining	30	42	39%	17.6	-41%	-58%

- Detailed near-term electricity sector modeling in IPM indicates that the decrease in coal usage may be smaller than the decrease shown in the economy-wide models.
- The results for all 35 sectors and for 2050 are available in Appendix 4.

FMPA-POD1-00124
HEARING EXHIBIT - 00000287

Results: Scenario 10 – S. 2191 Alt. Ref.

2030 Selected Sectoral Results (IGEM)

Sector	2007	2030				
		Alternative Reference		S.2191 Alt. Ref.		
	Output ($Billions)	Output ($Billions)	Percent Change from 2007	Output ($Billions)	Percent Change from 2007	Percent Change from Reference
Personal and business services	4468	8503	88%	8373.7	87%	-2%
Finance, insurance and real estate	2743	6377	130%	6234.7	127%	-2%
Transportation and warehousing	707	1340	89%	1267.0	79%	-5%
Food and kindred products	588	1240	104%	1292.3	120%	4%
Motor vehicles	529	1148	114%	1066.3	101%	-7%
Electric utilities (services)	396	540	43%	469.7	19%	-13%
Petroleum refining	305	369	31%	306.2	0%	-17%
Gas utilities (services)	52	61	20%	45.2	-13%	-26%
Coal mining	30	37	39%	18.8	-37%	-48%

- Detailed near-term electricity sector modeling in IPM indicates that the decrease in coal usage may be smaller than the decrease shown in the economy-wide models.
- The results for all 35 sectors and for 2050 are available in Appendix 4.

FMPA-POD1-00125
HEARING EXHIBIT - 00000288

Results: Scenario 2 – S. 2191
2030 Selected Sectoral Results (IGEM)

- The previous slides shows the impacts of S. 2191 case on the value of output of nine of the 35 IGEM sectors. These sectors correspond roughly to the two digit NAICS classification. (Results for the remaining sectors are presented in the appendix).
- The largest sectors in IGEM (personal and business services and finance, insurance and real estate) account for some fourteen trillion dollars of economic activity in 2030 and are only modestly affected by the policy.
- Transportation (freight and warehousing) and motor vehicle manufacturing do experience reductions in the value of their output, as consumers and other sectors substitute away from energy consumption. The model does not explicitly represent technology, and does not show the possible impact of new transportation technologies.
- In response to S. 2191, the food and kindred products sector is an example in IGEM of a sector which experiences a growth in demand, as consumers substitute away from other goods which may be more energy intensive.
- The energy production and transformation sectors experience reduction in output as other industries and consumers substitute capital, labor, and non-energy inputs.[1]
- Under the assumptions of the Alternative case, impacts on energy industries are less significant than under the reference case assumptions.

[1] Note that the coal industry shows large declines in output by 2030. Most domestic coal is consumed by the electricity sector, and IGEM does not explicitly represent generation technologies such as carbon capture and sequestration. The ADAGE model does represent generation technologies, and also shows that coal output decreases by 2030, but after 2030, all fossil generation is eventually replaced by coal fired integrated combined cycle and gasification plants with carbon capture and sequestration technologies, and coal output increases. See slide in Appendix on Primary Energy Use from ADAGE.

FMPA-POD1-00126

HEARING EXHIBIT - 00000289

Results: Scenario 2 – S. 2191

Total Abatement Cost

Scenario 2 - S.2191

	2015	2020	2025	2030	2035	2040	2045	2050
Domestic Covered Abatement and Allowance Set-Asides (MMTCO2e)								
ADAGE	2,473	3,099	3,610	4,329	5,026	5,375	5,712	6,026
IGEM	2,234	2,648	3,139	3,680	4,340	5,042	5,787	6,600
Domestic Offset Abatement (MMTCO2e)								
ADAGE	392	619	596	558	511	512	508	501
IGEM	529	611	602	596	566	526	481	427
International Credits (MMTCO2e)								
ADAGE	624	619	596	558	511	512	508	501
IGEM	619	611	602	596	566	526	481	427
Allowance Price ($/tCO2e)								
ADAGE	$29	$37	$48	$61	$77	$98	$125	$159
IGEM	$40	$51	$65	$83	$106	$135	$173	$220
Offset Price ($/tCO2e)								
ADAGE	$29	$30	$27	$23	$24	$28	$29	$31
IGEM	$40	$29	$27	$24	$27	$29	$28	$26
International Credit Price ($/tCO2e)								
ADAGE	$9	$12	$15	$20	$25	$32	$41	$52
IGEM	$9	$12	$15	$20	$25	$32	$41	$52
Domestic Covered Abatement Cost (Billion 2005 Dollars)								
ADAGE	$36	$58	$86	$131	$194	$264	$357	$479
IGEM	$45	$67	$102	$153	$230	$341	$499	$727
Domestic Offset Abatement Cost (Billion 2005 Dollars)								
ADAGE	$8	$9	$8	$6	$6	$7	$7	$8
IGEM	$11	$9	$8	$7	$8	$8	$7	$6
International Credit Payments (Billion 2005 Dollars)								
ADAGE	$6	$7	$9	$11	$13	$16	$21	$26
IGEM	$6	$7	$9	$12	$14	$17	$20	$22
Total Abatement Cost (Billion 2005 Dollars)								
ADAGE	$48	$74	$103	$149	$213	$288	$386	$513
IGEM	$61	$84	$119	$172	$251	$365	$526	$754

- The allowance price is equal to the marginal cost of abatement.
- The offset price is the marginal cost of abatement for uncovered sectors and entities in the U.S.
- The international credit price is the marginal cost of abatement outside of the U.S.
- Domestic covered abatement cost is approximated for each model as the product of domestic covered GHG emissions abatement and the allowance price divided by two.
  - Division by 2 is assumed to represent the fact that most reduction measures are not implemented at the marginal allowance price but at lower prices. In most cases, the relationship between emission reduction and the marginal price is a concave curve – which implies a value larger than 2. The value of 2, used here for simplicity leads to an overestimation of abatement costs.
- Domestic offset abatement cost is approximated for each model as the product of domestic offset abatement and the offset price divided by two.
- International credit payments are calculated for each model as the product of the amount of international credits purchased and the international credit price.
  - Unlike the abatement costs associated with domestic covered abatement and domestic offsets, there is no need for dividing by two when calculating the costs of international credits as all international credits are purchased at the full price of international allowances and those payments are sent abroad.
- Total abatement cost is simply the sum of domestic covered abatement cost, domestic offset abatement cost, and payments for international credits.

FMPA-POD1-00127

HEARING EXHIBIT - 00000290

Regional Modeling Results

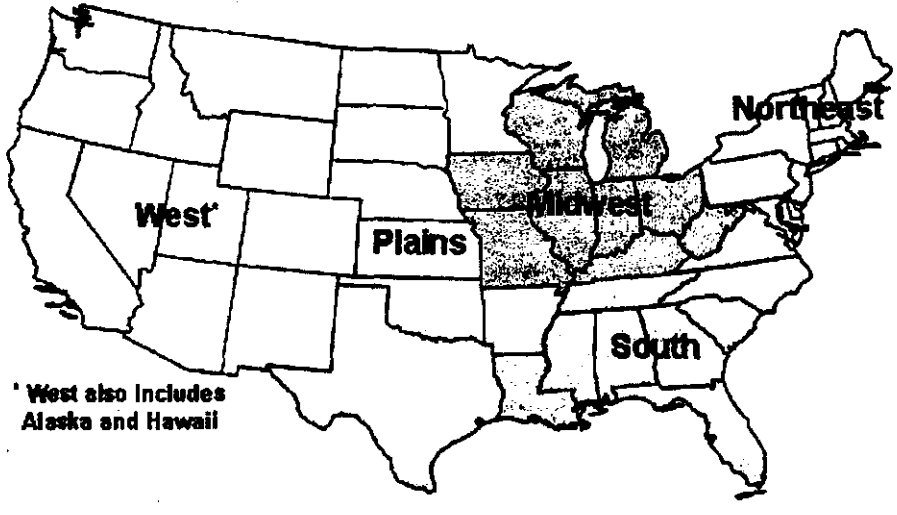
FMPA-POD1-00128

HEARING EXHIBIT - 00000291

Introduction to Regional Results

(ADAGE)

- ADAGE models 5 regions in the U.S.
  - West, Plains, Midwest, South and Northeast
- Difference in regional results can be attributed to a variety of factors:
  - Economic Base
    - Energy industry composition
    - Manufacturing industry composition
  - Energy Use
    - Efficiency and types of manufacturing
    - Household heating and cooling needs
    - Transportation systems and average distances traveled
  - Electricity Generation
    - Existing fossil fuel capacity
  - Allowance Allocation
    - Allocation impacts regional consumption, income, and GDP

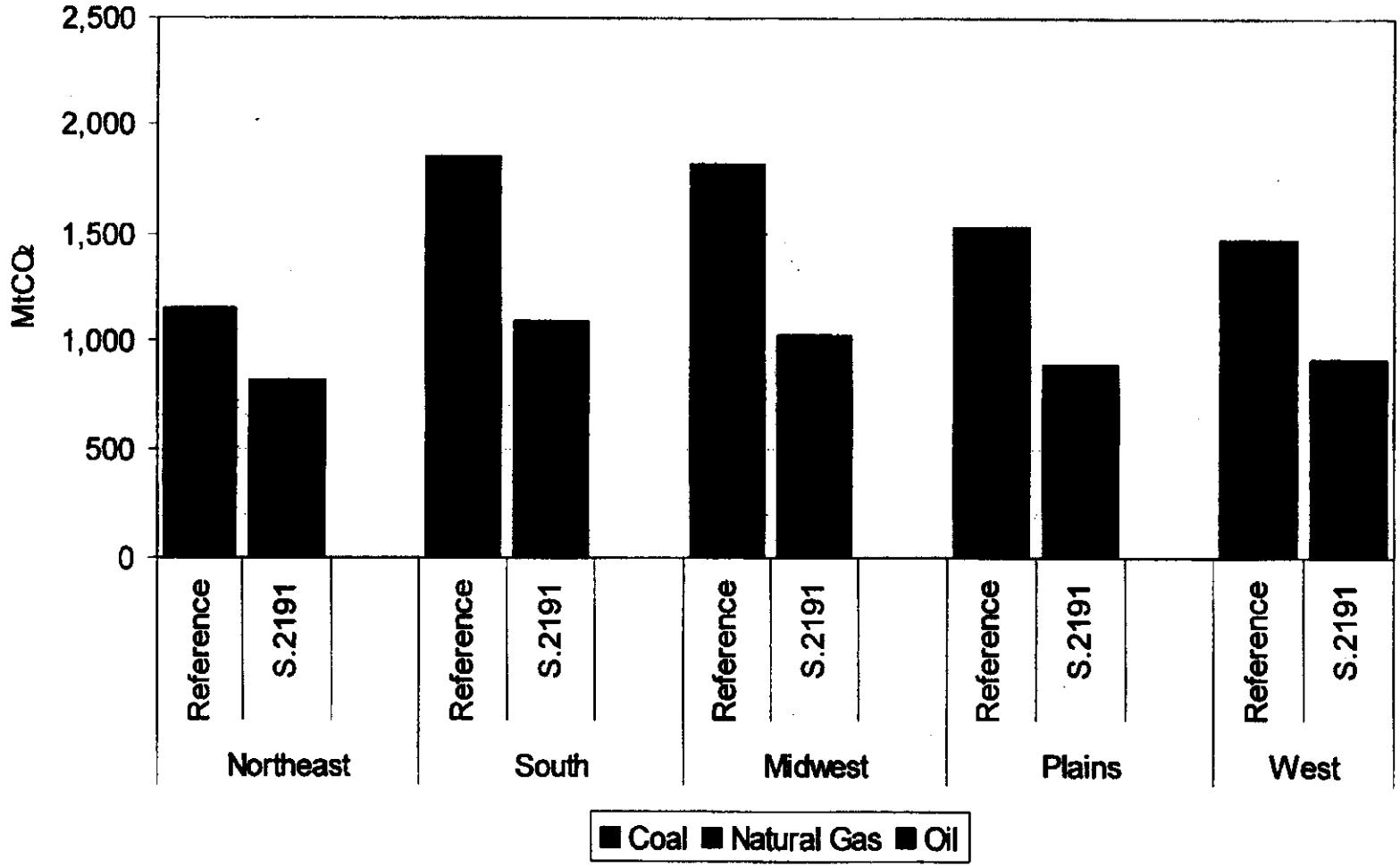


FMPA-POD1-00129

HEARING EXHIBIT - 00000292

Results: Scenario 2 - S. 2191

Regional CO_2 from Energy Use - **2030** (ADAGE)

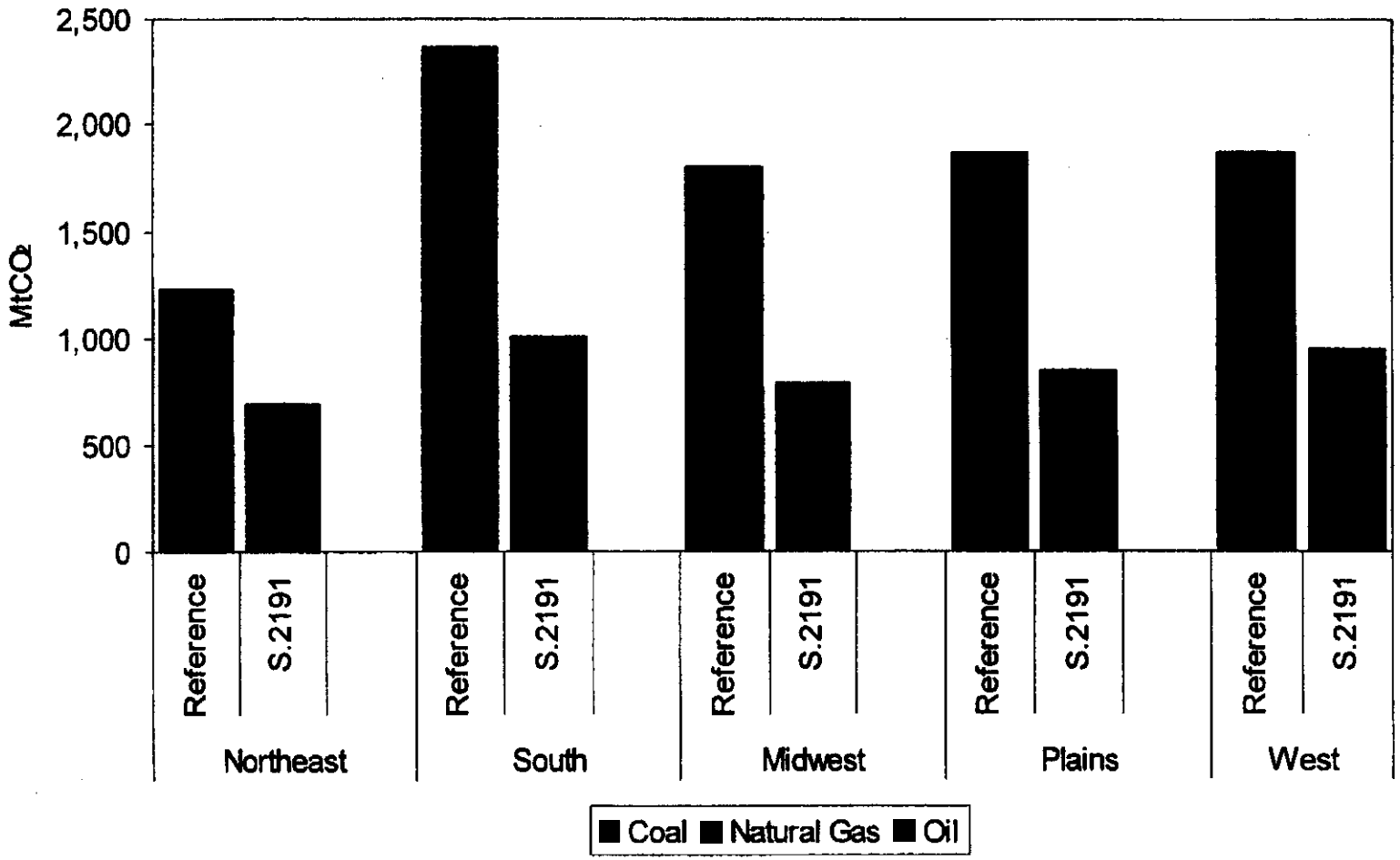


FMPA-POF-1-00130

HEARING EXHIBIT - 00000293

Results: Scenario 2 - S. 2191

Regional CO_2 from Energy Use - **2050** (ADAGE)



FMPA-POD1-00131

HEARING EXHIBIT - 00000294

Results: Scenario 2 - S. 2191

Regional GDP and Consumption (ADAGE)

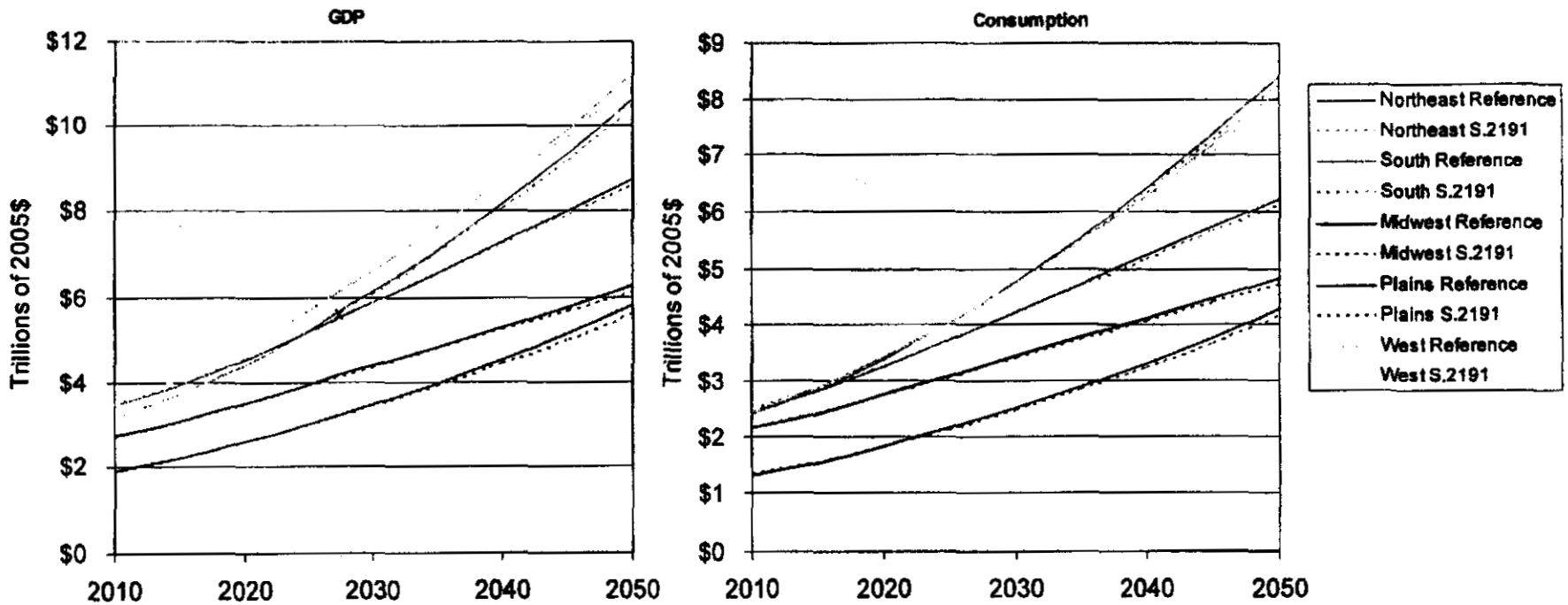


Table: % Change in Regional GDP
Scenario 2 - S.2191

	2010	2020	2030	2040	2050
Northeast	-0.1%	-0.5%	-0.6%	-1.1%	-1.9%
South	-0.2%	-0.6%	-0.7%	-1.3%	-2.2%
Midwest	-0.2%	-0.8%	-1.1%	-1.5%	-2.6%
Plains	-0.2%	-1.3%	-1.8%	-2.6%	-3.8%
West	-0.2%	-0.6%	-0.7%	-1.3%	-2.2%

Table: % Change in Regional Consumption
Scenario 2 - S.2191

	2010	2020	2030	2040	2050
Northeast	-0.8%	0.2%	0.6%	1.3%	1.9%
South	-0.8%	0.3%	0.7%	1.1%	1.7%
Midwest	-0.8%	0.5%	1.1%	1.6%	2.6%
Plains	-0.2%	1.4%	1.9%	2.4%	3.3%
West	-0.7%	0.2%	0.7%	1.1%	1.7%

FMPA-POD1-00132

HEARING EXHIBIT - 00000295

Results: Scenario 2 - S. 2191

Regional Results Discussion (ADAGE)

- Reference CO_2 emissions are highest in the South and Midwest regions, largely stemming from coal use by electric utilities.
- The most significant reductions in CO_2 across all regions are from coal:
  - By 2030, electric utilities are reducing coal and switching to natural gas.
  - By 2050, coal use by utilities has rebounded as Advanced Coal + CCS technologies penetrate the market.
  - Emissions from coal continue to decline through 2050 through use of these advanced CCS options.
- The decline in CO_2 emissions from petroleum is more modest across all regions.
- Although natural gas consumption remains relatively steady through 2030 to meet higher demand from utilities, these emissions also decline by 2050.
- The largest reductions, in both GDP and consumption, are seen in the Plains region.
- Percent changes in GDP and consumption are less than 3% throughout the time frame in all other regions.
- All other regions (Northeast, South, Midwest, West) see an initial increase in consumption, followed by a decrease by 2015.

FMPA-POD1-00133

HEARING EXHIBIT - 00000296

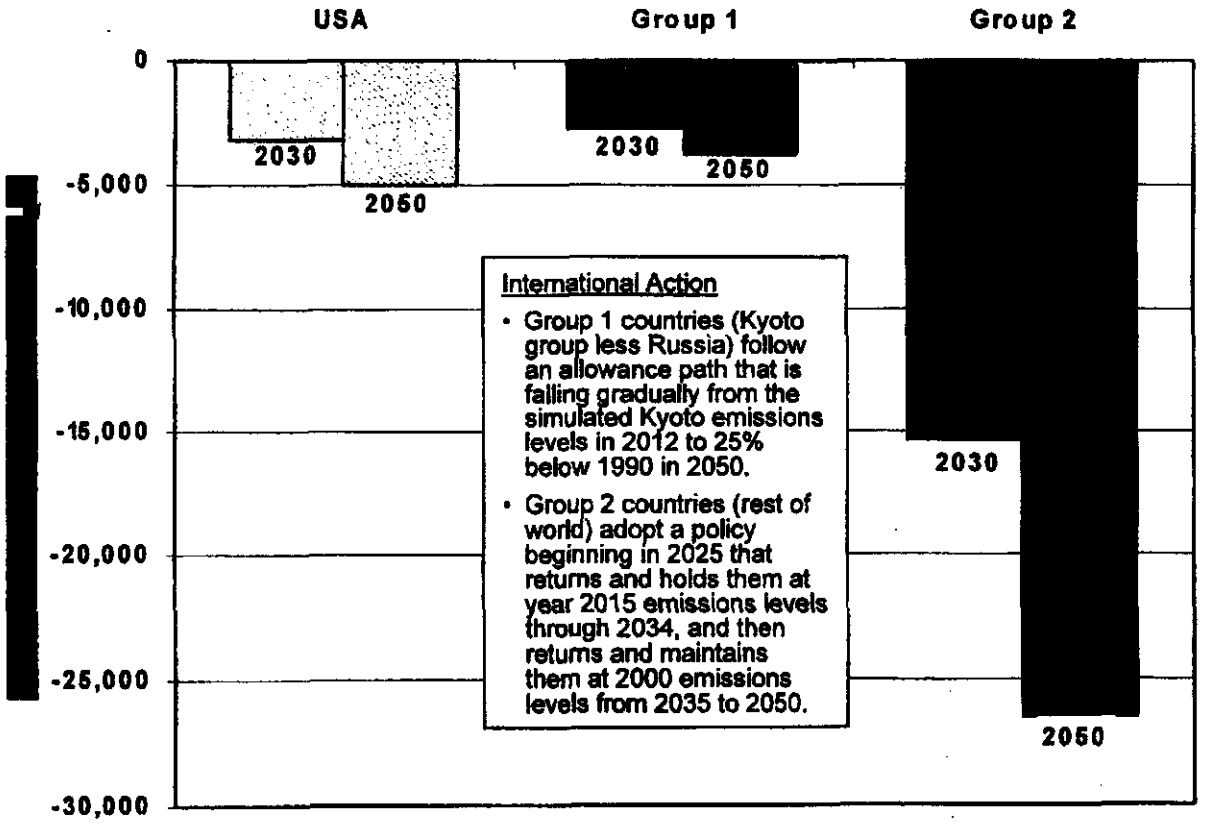
Global Results:
Emissions Leakage and
Alternative International Action Sensitivities

FMPA-POD1-00134

HEARING EXHIBIT - 00000297

Results: Scenario 2 – S. 2191

International GHG Emissions Leakage (ADAGE)

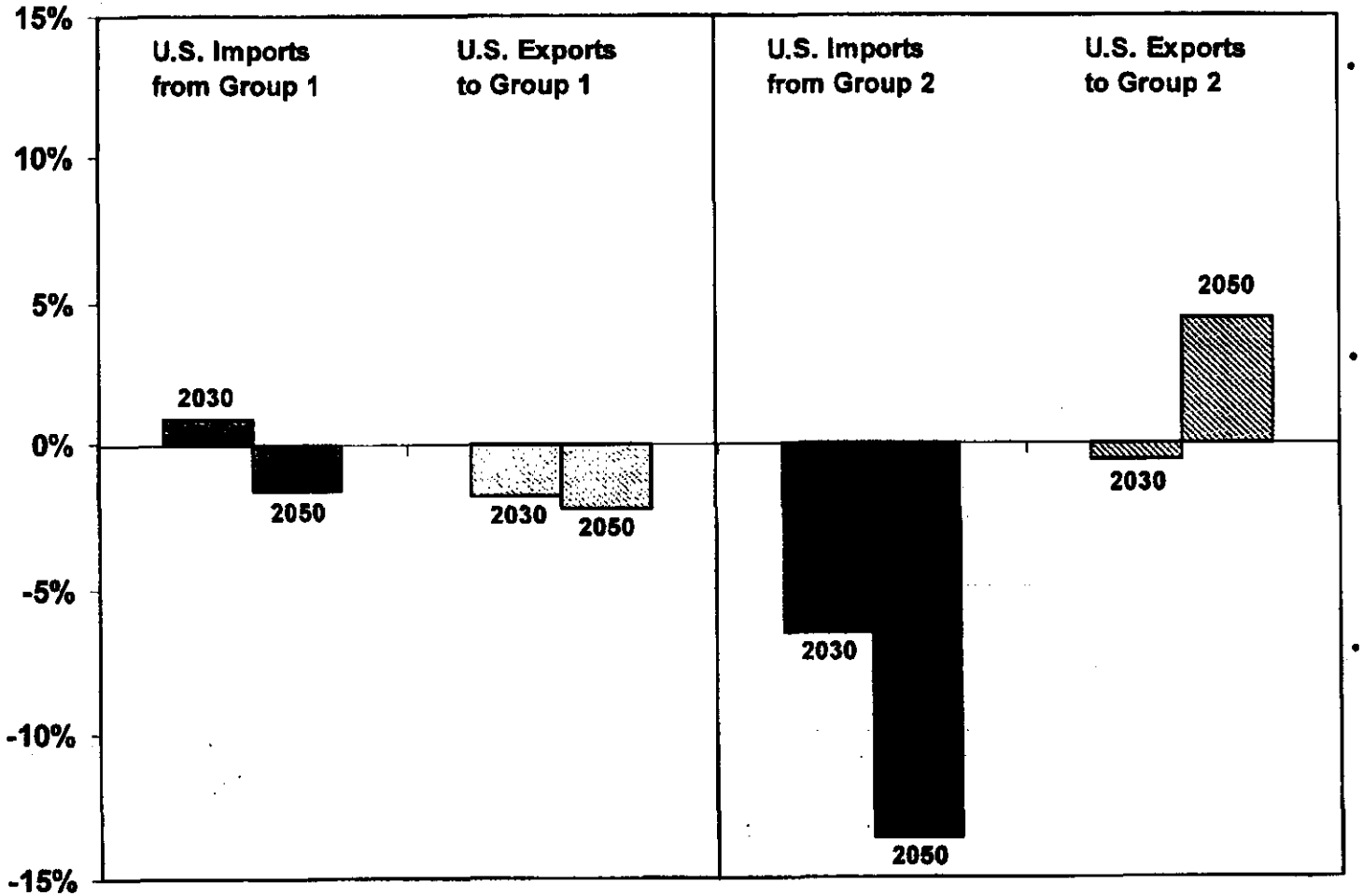


- Emissions leakage occurs when a domestic GHG policy causes a relative price differential between domestically produced goods and imported goods, which causes production of goods that domestically would have GHG allowance prices embodied in their cost to shift abroad, and thus causes an increase in GHG emissions in other countries.
- Under the Scenario 2 - S. 2191 international assumptions, no international emissions leakage occurs.
- Emissions in Group 2 fall by over 26,000 $MtCO_2e$ as they adopt emission targets beginning in 2025.
- Emission reductions are greater in 2050 than in 2030 for all regions as they face more stringent targets.

FMPA-POD1-00135
HEARING EXHIBIT - 00000298

Results: Scenario 2 – S. 2191

International Trade Leakage for Energy-Intensive Manufacturing (ADAGE)



- Under Scenario 2 – S. 2191, imports of energy-intensive manufacturing goods from Group 2 to the U.S. fall as Group 2 takes on emission targets.
- The U.S. exports more energy-intensive manufacturing goods to Group 2, particularly in 2050 as Group 2 is meeting a stable emission target from 2035 to 2050.
- Trade of energy-intensive manufactured goods with Group 1 countries falls somewhat as both groups face emissions targets.

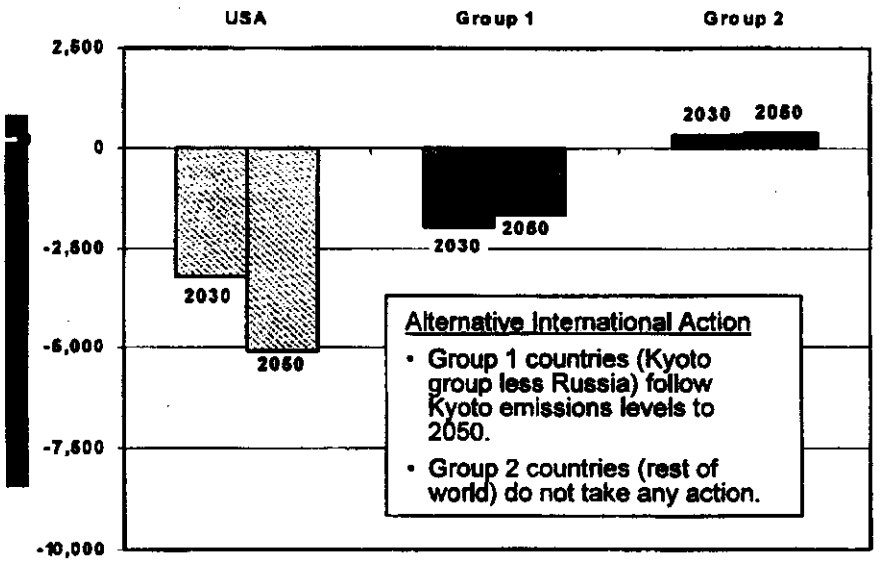
FMPA-POD1-00136

HEARING EXHIBIT - 00000299

Results: Scenario 3 - S. 2191, Alternative International Action

International GHG Emissions Leakage (ADAGE)

- Emissions leakage occurs when a domestic GHG policy causes a relative price differential between domestically produced and imported goods. This causes domestic production, which embodies the GHG allowance price to shift abroad, and thus an increase in GHG emissions in other countries. Additionally, emissions leakage not associated with trade effects may occur when a GHG policy reduces domestic consumption of oil, lower demand for oil lowers the world oil price, which increases oil consumption in countries without a GHG policy thus increasing emissions.
- As a result of S. 2191, the prices of U.S. exports rise relative to prices in the rest of the world, and export volumes fall. Since exports are price-elastic the volumes fall proportionally more than the price rises and thus the value of exports declines. Imports are reduced in part by the overall reduction in spending associated with the lower levels of consumption. Additionally, commodities directly effected by the emissions cap (e.g. oil) are reduced proportionally more than other imports due to the allowance prices embodied in their cost. Import substitution counterbalances the above two forces. U.S. prices of commodities not directly affected by the policy are relatively higher, which leads to substitution away from domestically produced goods and towards imported goods.
- In Scenario 3 – S. 2191, Alternative International Action , the International Reserve Allowance Requirement is assumed to be triggered, due to inaction in Group 2 countries.
- Group 2 emissions rise by 350 $MtCO_2e$ in 2030, and 385 $MtCO_2e$ in 2050, since developing countries do not take any action. This is a less than 1% increase in Group 2 emissions from the reference levels, and is equivalent to U.S. emissions leakage rates of approximately 11% in 2030 and 8% in 2050.
- While Group 2 is not taking any action in this scenario, their emissions are somewhat limited by demand from the U.S. and Group 1 for offset credits from Group 2. This results in smaller amounts of leakage than may otherwise be expected.*
- The sensitivity case without the International Reserve Allowance Requirement results in a minimal effect on emissions leakage, with an increase in Group 2 emissions of 361 $MtCO_2e$ in 2030, and an increase of 412 $MtCO_2e$ in 2050 without the requirement included.
- Group 1 emissions fall by a lesser amount in 2050 than in 2030 as Group 1 follows a "Kyoto forever" constant emissions target, and greater emission reductions are needed in the earlier years to meet these targets.



* For example Paltsev (2001) indicates that in a policy limited to industrialized countries, leakage rates can range from 5% - 34% for individual countries, although international trading may reduce that by half. One important difference between Paltsev (2001) and this analysis is that S. 2191 requires greater emissions reductions than those modeled in Paltsev (2001). This means that economic activity is reduced more under S. 2191, which results in greater reductions in overall consumption and imports. Counterbalancing this effect is the greater relative price differential, which causes a larger import substitution effect.

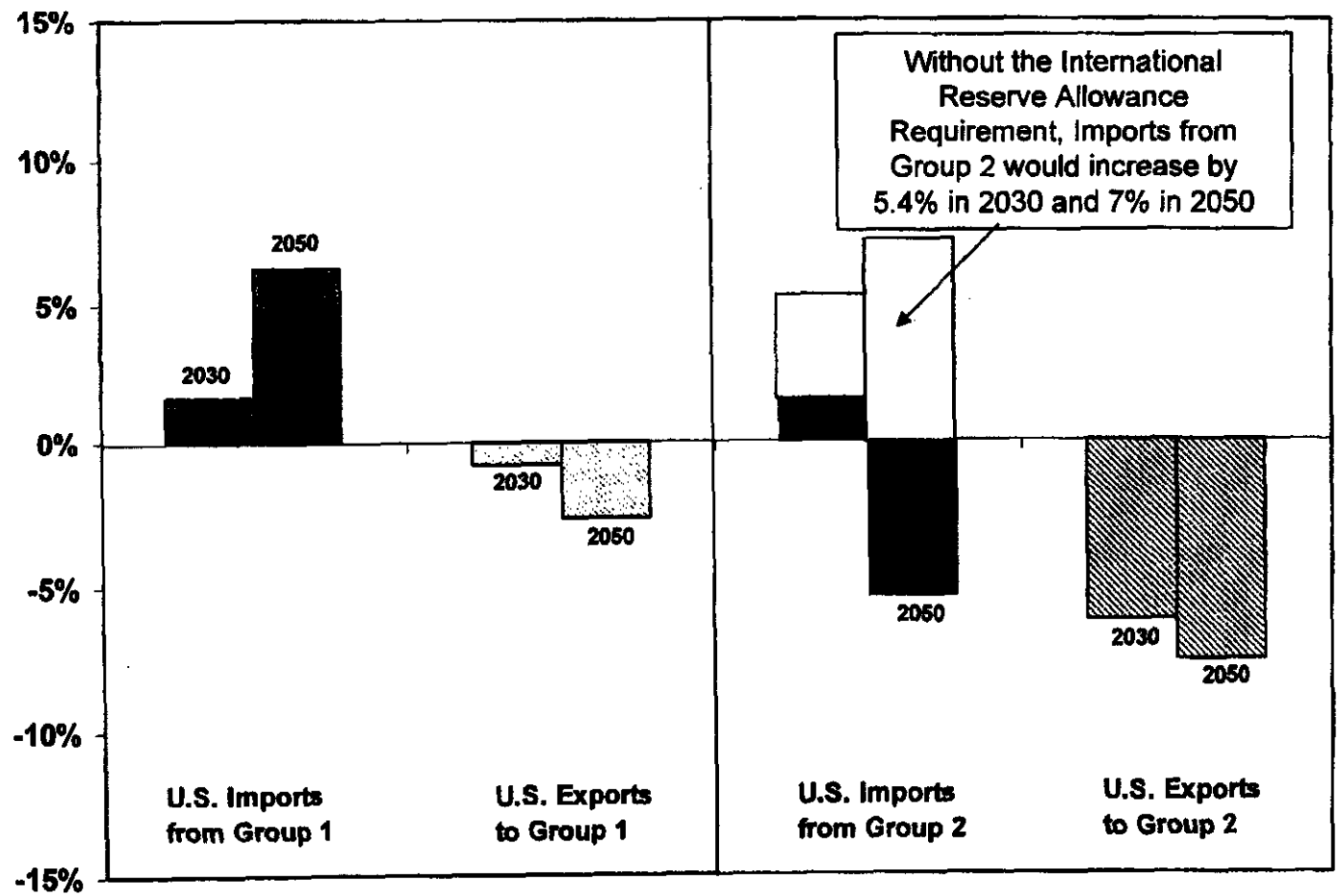
Paltsev, Sergey V. "The Kyoto Protocol: Regional and Sectoral Contributions to the Carbon Leakage." *The Energy Journal*, 2001, volume 22, number 4, pages 53-79.

FMPA-POD1-00137

HEARING EXHIBIT - 00000300

Results: Scenario 3 - S. 2191, Alternative International Action

International Trade Leakage for Energy-Intensive Manufacturing (ADAGE)



- Under Scenario 2 – S. 2191, Alternative International Action, imports of energy-intensive manufacturing goods from Group 2 countries to the U.S. rise in 2030 since Group 2 countries are not taking any emissions action.
- The International Reserve Allowance Requirement limits the imports from Group 2.
  - The International Reserve Allowance Requirement has no effect on GDP in 2030, and increases GDP impacts by $34 billion (or 0.08 percentage points) in 2050.
- The U.S. is exporting less energy-intensive manufacturing goods to Group 2, as Group 2 uses more of their domestic energy-intensive manufacturing, resulting in increased emissions in Group 2.
- Trade of energy-intensive manufactured goods with Group 1 countries is a mixed story as policies in all regions, as well as the International Reserve Allowance Requirement, interact in 2030 & 2050.

FMPA-POD1-00138

HEARING EXHIBIT - 00000301

Offsets and International Credits

EMPA-POD1-00139

HEARING EXHIBIT - 00000302

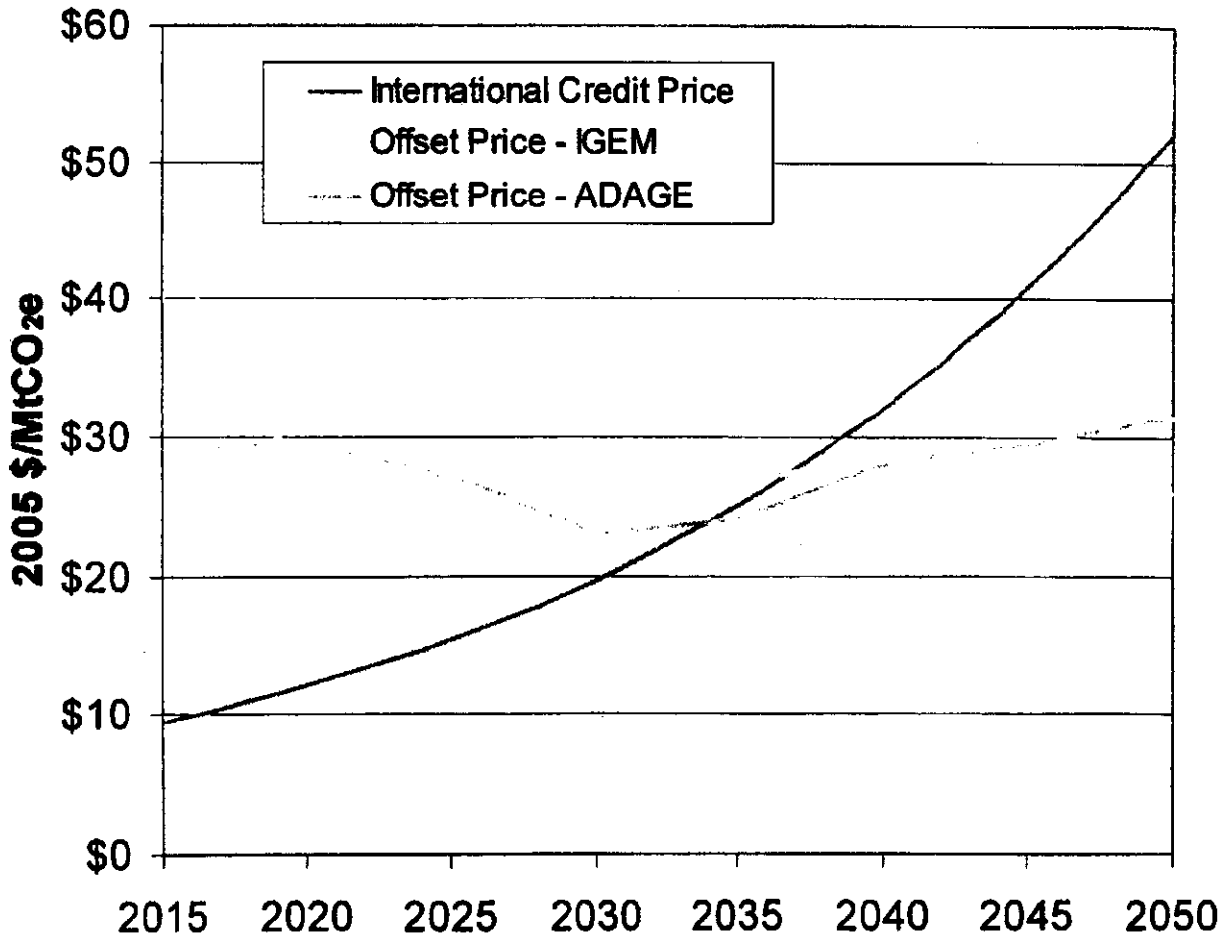
Domestic Offsets & International Credits Methodology Highlights

- EPA developed mitigation cost schedules for 24 offset mitigation categories, covering the following mitigation types:
  - Domestic non-CO_2 GHG emissions reductions
  - International non-CO_2 GHG emissions reductions
  - Domestic and international increases in terrestrial carbon sinks (soil and plant carbon stocks)
  - International energy-related CO_2 mitigation
- EPA evaluated individual mitigation options to determine potential eligibility and feasibility over time for a future mitigation program
  - Based on EPA's emissions inventory & mitigation program expertise
    - Considered a broad set of factors, including existing and emerging programs/protocols/tools, monitoring, measurement & verification (MMV), magnitude of potential, additionality, permanence, leakage, and co-effects
  - Options evaluated both domestically, internationally (by region group), and over time
  - Captured responses to rising carbon prices
    - Modeled rising carbon price pathways (vs. constant) to capture investment behavior
    - Applied in three mitigation categories: Domestic agriculture & forestry, international forestry, and international energy-related CO_2
  - Capped sector non-CO_2 and bio-energy emissions reductions are also modeled.
  - For the individual mitigation options that were determined to be eligible, no further discounting was assumed.

FMPA-POD1-00140
HEARING EXHIBIT - 00000303

Results: Scenario 2 - S. 2191

Offset and International Credit Prices



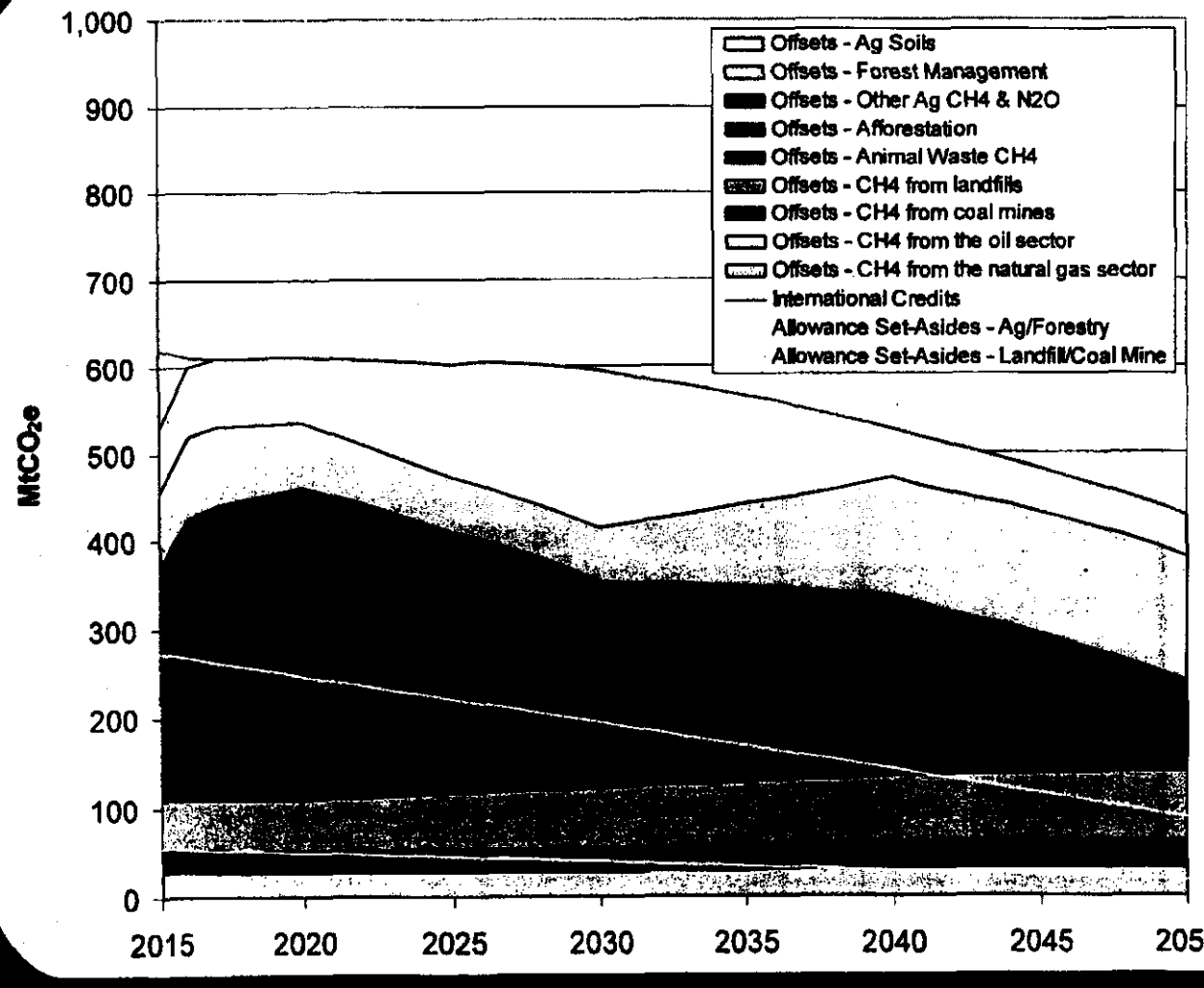
- S. 2191 limits the use of offsets and international credits to 15% of allowance submissions.
- The 15% limit on the use of domestic offsets is binding in IGEM starting in 2017, and in ADAGE starting in 2015.
- In IGEM, the offset price is equal to the GHG allowance price before 2017 when the 15% limit is not binding.
- Starting in 2017 in IGEM, and 2015 in ADAGE, when the 15% limit is binding, the offset price is lower than the GHG allowance price.
- The international credit price is driven by the international demand and supply of GHG abatement.
- This scenario assumes that offsets are not discounted, if offsets were discounted, the offset price would be expected to rise.

FMPA-POD1-00141

HEARING EXHIBIT - 00000304

Results: Scenario 2 - S. 2191

Allowance Set-Aside, Offset, and International Credit Abatement (IGEM)



- The total quantity of abatement from domestic offsets is limited to 15% of allowance submissions in each year.
- The quantity of abatement from international credits is similarly limited to 15% of allowance submissions in each year.
- The quantity of abatement from allowance set-asides is proscribed by the bill, 4% of allowances in each year are set aside for Ag/Forestry abatement projects, and 1% are set aside for landfill and coal mine CH_4 abatement projects.
- Because the offset price is lower than the GHG allowance price, projects that are eligible for both allowance set-asides and offsets would prefer to be in the allowance set-aside program.

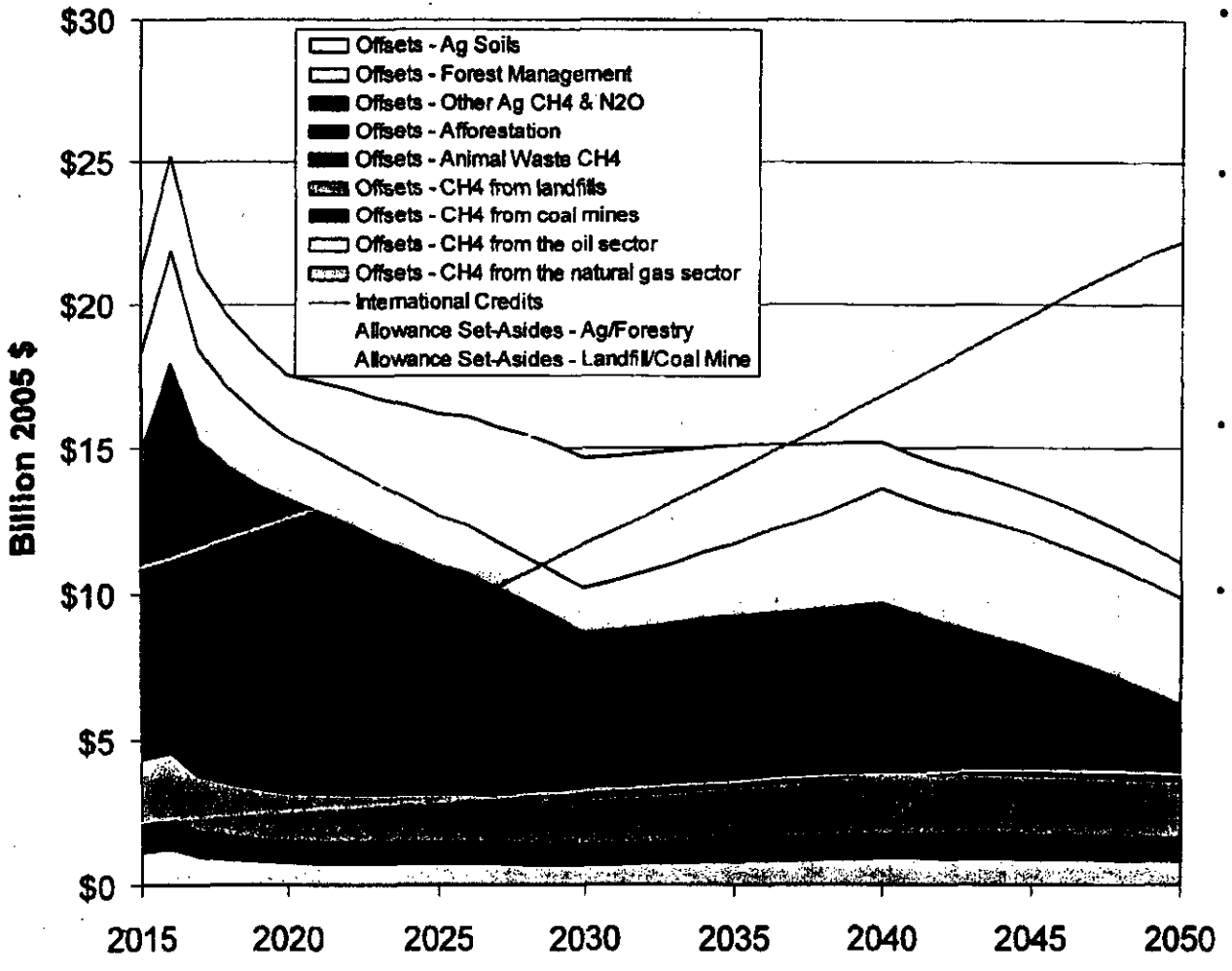
EPA Analysis of S. 2191

FMPA-POD1-00142

HEARING EXHIBIT - 00000305

Results: Scenario 2 - S. 2191

Allowance Set-Aside, Offset, and International Credit Payments (IGEM)



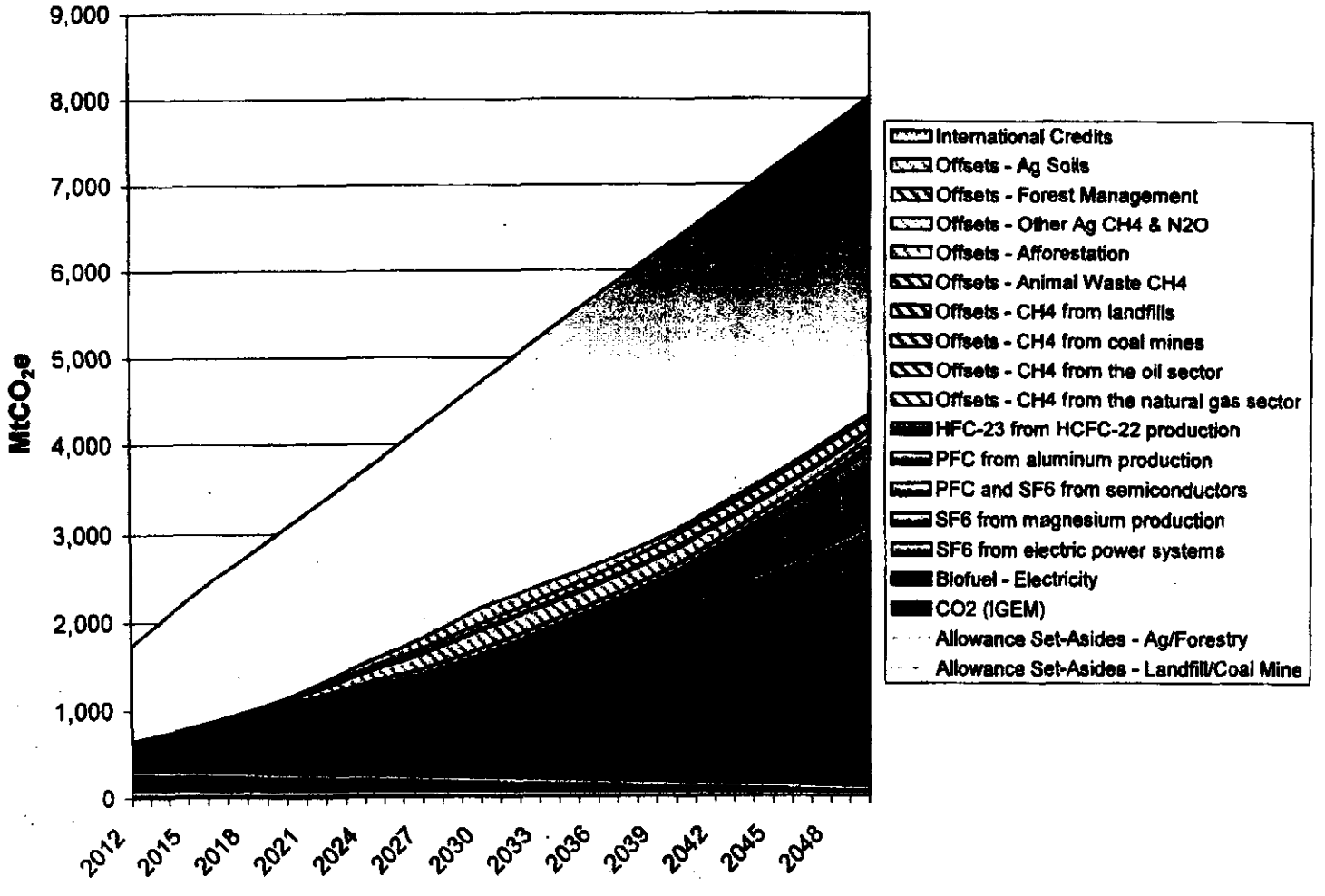
- Payments for offsets are simply determined by multiplying the offset price by the quantity of offsets supplied from each source.
- Before 2017, offset payments are considerably higher than in later years. This is driven by the high offset prices in these early years when the 15% limit on the use of offsets is not binding, and the offset price is thus equal to the price of GHG allowances.
- Payments for international credits are simply the product of the international credit price and the quantity of international credits purchased.
- Similarly, the value of the allowance set-asides is the product of the GHG allowance price and the quantity of abatement associated with the allowance set-aside programs.

EPA Analysis of S. 2191

EPA-POD1-00143
HEARING EXHIBIT - 00000306

Results: Scenario 4 - S. 2191, Unlimited Offsets

Sources of GHG Abatement (IGEM)



FMPA-POD1-00144

HEARING EXHIBIT - 00000307

Results: Scenario 4 - S. 2191, Unlimited Offsets

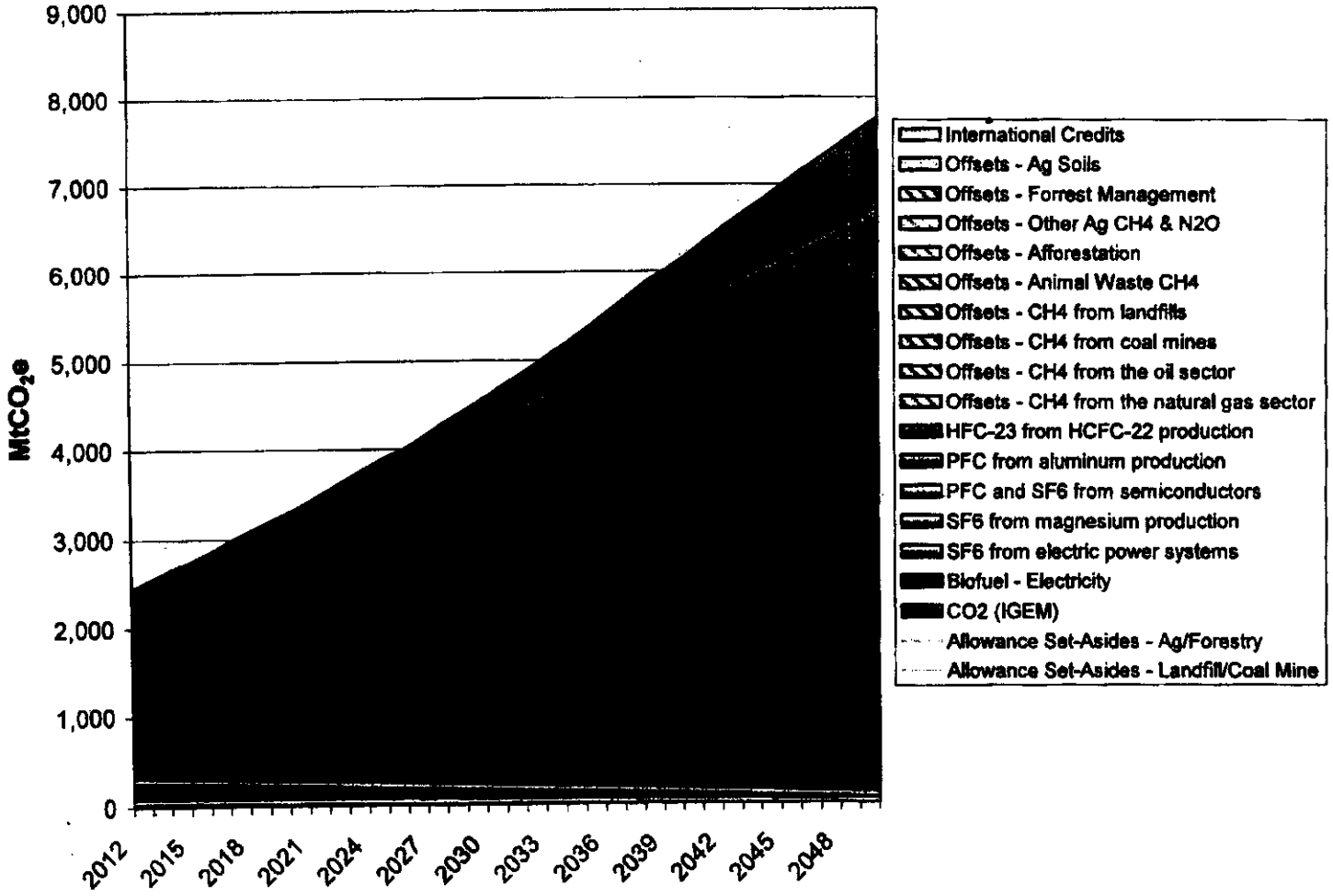
Sources of GHG Abatement (IGEM)

- The previous chart shows, for the IGEM model, the sources of CO_2 and non-CO_2 GHG abatement under S. 2191 with unlimited offsets.
- IGEM does not break out CO_2 emissions by sector, so the bottom purple area represents all energy related CO_2 emissions abatement within IGEM.
  - The other sources of abatement represented here are derived from EPA's non-CO_2 GHG spreadsheet tools for estimating projections and mitigation of CH_4, N_2O, and F-gases (NCGM), and the Forest and Agriculture Sector Optimization Model, GHG version (FASOMGHG).
- The areas toward the top of the chart shaded with hashed lines show emissions reductions from domestic offsets and the red shaded area at the very top shows international credits
  - International credits make up the largest portion of abatement in all years. 52% of abatement comes from international credits in 2030, and 45% in 2050.
    - Note that In terms of compliance obligation (which is limited to 15% for international credits in the bill as written) 65% comes from international credits in 2030, and 169% comes from international credits in 2050. It is possible for greater than100% of compliance obligation to come from international credits when the quantity of international credits purchased is greater than the level of emissions less offsets and international credits that is required to meet the cap.
  - Domestic offsets make up a smaller portion of abatement than in Scenario 2 where offsets are limited. This is because the allowance price in the unlimited case is lower than the domestic offset price in the limited case, so fewer domestic offsets are supplied.
- The light green and blue lines at the bottom represent GHG abatement from allowance set-asides. This abatement is additional to the abatement in covered sectors and offset projects that is used to meet the cap.

FMPA-POD1-00145
HEARING EXHIBIT - 00000308

Results: Scenario 5 - S. 2191, No Offsets

Sources of GHG Abatement (IGEM)



FMPA-POD1-00146

HEARING EXHIBIT - 00000309

Results: Scenario 5 - S. 2191, No Offsets

Sources of GHG Abatement (IGEM)

- The previous chart shows, for the IGEM model, the sources of CO_2 and non-CO_2 GHG abatement under S. 2191 with no offsets.
- IGEM does not break out CO_2 emissions by sector, so the bottom purple area represents all energy related CO_2 emissions abatement within IGEM.
  - The other sources of abatement represented here are derived from EPA's non-CO_2 GHG spreadsheet tools for estimating projections and mitigation of CH_4, N_2O, and F-gases (NCGM), and the Forest and Agriculture Sector Optimization Model, GHG version (FASOMGHG).
- Without offsets as an option, all abatement must come from capped sectors, which dramatically increases the allowance price.
- The light green and blue lines at the bottom represents GHG abatement from allowance set-asides. This abatement is additional to the abatement in covered sectors and offset projects that is used to meet the cap.

FMPA-POD1-00147
HEARING EXHIBIT - 00000310

Results: International Offsets Sensitivity Scenarios (4, 5, and 10)

GDP and Consumption (IGEM)

Table: GDP Comparisons (% Change from Reference)

	2015	2020	2025	2030	2035	2040	2045	2050
2) S. 2191								
IGEM	-2.0%	-2.6%	-3.1%	-3.8%	-4.4%	-5.2%	-6.0%	-6.9%
4) S. 2191 Unlimited Offsets								
IGEM	-0.7%	-0.9%	-1.1%	-1.3%	-1.6%	-1.9%	-2.3%	-2.7%
5) S. 2191 No Offsets								
IGEM	-3.3%	-4.1%	-5.0%	-5.9%	-6.9%	-7.9%	-9.0%	-10.1%
10) S. 2191 High Technology								
IGEM	-0.7%	-0.9%	-1.1%	-1.3%	-1.6%	-1.9%	-2.3%	-2.7%

Table: Consumption Comparisons (% Change from Reference)

	2015	2020	2025	2030	2035	2040	2045	2050
2) S. 2191								
IGEM	-0.2%	-0.7%	-1.1%	-1.4%	-1.9%	-2.3%	-2.7%	-3.3%
4) S. 2191 Unlimited Offsets								
IGEM	0.0%	-0.2%	-0.4%	-0.5%	-0.7%	-0.8%	-1.0%	-1.2%
5) S. 2191 No Offsets								
IGEM	-0.3%	-1.2%	-1.8%	-2.5%	-3.2%	-3.9%	-4.5%	-5.3%
10) S. 2191 High Technology								
IGEM	0.0%	-0.2%	-0.4%	-0.5%	-0.7%	-0.8%	-1.0%	-1.2%

FMPA-POD1-00148
HEARING EXHIBIT - 0000311

Additional Qualitative Considerations

FMPA-POD1-00149

HEARING EXHIBIT - 00000312

Allowance Allocation & Revenue Recycling in ADAGE and IGEM

- In the models used for this analysis, households are represented by a single representative consumer. Since the behavior of employee-shareholders do not vary by industry, the initial allocation of allowances to different industries does not affect estimated model outcomes.
- In this analysis we assume that the policy is deficit and revenue neutral, which implies that the market outcomes are invariant to the auction / allocation spilt
  - Private sector revenues from allocated allowances accrue to employee-shareholder households, and the government adjusts taxes lump sum to maintain deficit and spending levels.
  - Allowance auction revenues flow to the U.S. government, and are redistributed to households lump sum to the extent that deficit and spending levels are maintained. If auction revenues were directed to special funds instead of returned directly to households as modeled, the impact on household annual consumption and GDP would be greater. If the auction revenues were instead used to lower distortionary taxes, the costs of the policy would be lower.

FMPA-POD1-00150
HEARING EXHIBIT - 00000313

Revenue Recycling Issues

- The use of the revenue generated by auctioning permits can affect the cost of the policy.
- Compared to returning auction revenues to consumers in a lump sum fashion that maintains revenue and deficit neutrality, other uses of auction revenues for other purposes can positively or negatively impact the cost of the policy.
  - Using auction revenues to lower distortionary taxes can lower the cost of the policy.
    - This possibility is known as the "double dividend" and has been widely discussed in the economics literature (e.g. Goulder et al. 1999, Parry et al. 1999, Parry and Oates 2000, and Parry and Bento 2000, CBO 2007).
    - One study (Parry and Bento 2000) finds that different methods of revenue recycling under a cap-and-trade system that reduces emissions by 10 percent can lead to economy-wide costs that differ by a factor of three.
  - Directing auction revenues to special funds or creating subsidies to specific technologies can raise the overall costs of a policy due to the need to finance these policies with increases in distortionary taxes (the converse of the "double dividend" benefit of reducing distortionary taxes discussed above).
    - However, substantial cost savings could be achieved by combining direct emissions policies (e.g. cap-and-trade or carbon tax) with technology push policies (e.g. technology and R&D incentives) that correct for the market failure associated with the fact that the inventor of a new technology can not appropriate all of the associated social benefits (Fischer and Newell 2005; Schneider and Goulder 1997).

FMPA-POD1-00151
HEARING EXHIBIT - 00000314

Allowance Allocation Issues

- Since emissions allowances are valuable assets, differing allowance allocation schemes can have differing equity implications.
- Equity considerations can justify allocating allowances to (or directing allowance auction revenue to) those who ultimately bear the cost of abatement.
- Who bears the ultimate burden of the costs of abatement is not determined by who is required to hold allowances (or who performs the abatement), but by the complex interaction of markets.
  - (Harberger 1962 provides the first general equilibrium model of tax incidence, Kotlikoff and Summers 1987 provides a useful review of the subsequent literature, CBO 2007 discusses the issue in the context of a cap-and-trade program).
- Freely allocating allowances to the entities required to hold allowances can create a windfall gain for those entities as they receive a valuable asset and pass the costs associated with abatement downstream to consumers.
  - Freely allocating less than a fifth of allowances to U.S. fossil fuel suppliers may be sufficient to prevent their profits from falling, and freely allocating a greater share of allowances could lead to increased profits (Bovenberg and Goulder 2001).
- Similar to creating subsidies, allocating allowances in a non lump sum fashion has a distortionary effect that raises costs.
  - E.g. allocating allowances based on the average number of production employees employed at a facility acts as a distortionary subsidy for labor.

FMPA-POD1-00152
HEARING EXHIBIT - 00000315

Tax Interaction Effects

- Distortions may also occur with tax interaction effects with labor, indirectly reducing the labor supply by increasing the distortionary effect of income taxes. (See Murray, Thurman, and Keeler, 2000)
  - Burtraw et al (2001) discuss three alternative allocation mechanisms and their resulting distributional impacts on consumers and producers. They demonstrate that allocation based on a generation performance standard acts as a generation subsidy and increases overall costs compared with allocation through auction.
  - Fischer, Kerr, and Toman (1998) discuss the types of risk associated with different allocation systems. They note that "external" risk (e.g. changes in caps due to international agreements or improved climate science) should be borne by the emitter while "internal" risk (e.g. political or revenue based motivations for changing caps) should be eliminated to the extent possible. They also address tax effects of different allocation systems and note that there are tax distortion effects in both grandfathering and auction systems (encouraging too much and too little banking, respectively) and that eliminating these effects would require a broad overhaul of the capital gains tax system.
  - Neuhoff, Grubb, and Keats (2005) demonstrate that the potential for future updating of the emissions allocation baseline in Europe creates distortionary incentives in operation and investment.
  - Burtraw, Kahn, and Palmer (2005) examine the proposed Regional Greenhouse Gas Initiative effort by nine NE/mid-Atlantic states and discuss the implications for individual firms' profits. They find that allocation mechanism impacts the price of electricity, consumption, and mix of production technologies. Additionally, they show that the regional nature of the system will allow for leakage, creating profit for firms outside the region.

FMPA-POD1-00153
HEARING EXHIBIT - 00000316

References

Bovenberg, A.L., and L.H. Goulder. 2001. Neutralizing the Adverse Industry Impacts of CO_2 Abatement Policies: What Does It Cost? In *Behavioral and Distributional Effects of Environmental Policies*, edited by C. Carraro and G. Metcalf. Chicago: University of Chicago Press.

Burtraw, D., D. Kahn, and K. Palmer. 2005. CO_2 Allowance Allocation in the Regional Greenhouse Gas Initiative and the Effect on Electricity Investors. Washington, D.C. RFF Discussion Paper No. 05-55.

Burtraw, D., K. Palmer, R. Bharvirkar, and A. Paul. 2001. The Effect of Allowance Allocation on the Cost of Carbon Emissions Trading. Washington, D.C. RFF Discussion Paper 01-30.

Congressional Budget Office (CBO). 2007. *Trade-Offs in Allocating Allowances for CO_2 Emissions*, April 25, 2007.

Fischer, C. 2004a. *Emission pricing, spillovers, and public investment in environmentally friendly technologies.* Washington, DC: Resources for the Future.

Fischer, C., and R. Newell. 2005. *Environmental and Technology Policies for Climate Mitigation*, working paper. Washington: Resources for the Future.

Fischer, C., M. A. Toman, and S. Kerr, 1998. Using Emissions Trading to Regulate U.S. Greenhouse Gas Emissions: An Overview of Policy Design and Implementation Issues. *National Tax Journal*, vol. 51, no. 3: 453-464.

Goulder, L.H., and W. Pizer. The Economics of Climate Change in Lawrence Blume and Steven Durlauf, eds., *The New Palgrave Dictionary of Economics*, Palgrave MacMillan, Ltd., forthcoming.

FMPA-POD1-00154

HEARING EXHIBIT - 00000317

References (con't)

Harberger, A.C. 1962. The incidence of the Corporation Income Tax. *Journal of Political Economy* 96: 339-57.

Jorgenson, D.W., R.J. Goettle, P.J. Wilcoxen, and M.S. Ho. 2000. The Role of Substitution in Understanding the Costs of Climate Change Policy. *Pew Center on Global Climate Change*. http://www.pewclimate.org/projects/substitution.pdf

Kotlikof, L.J., and L.H. Summers. 1987. Tax Incidence in *Handbook of Public Economics*, vol. 2, chap. 15. Amsterdam: Elsevier Science Publishers.

Murray, B. C., W. N. Thurman, and A. Keeler. 2000. Adjusting for Tax Interaction Effects in the Economic Analysis of Environmental Regulation: Some Practical Considerations. U.S. E.P.A. White Paper. http://www.epa.gov/ttnecas1/workingpapers/tie.pdfParry, I., and A.M. Bento. 2000. Tax Deductions, Environmental Policy, and the 'Double Dividend' Hypothesis. *Journal of Environmental Economics and Management*, vol. 39, no. 1, pp. 67-95.

Neuhoff, K., M. Grubb, and K. Keats. 2005. Impact of the Allowance Allocation on Prices and Efficiency. CWPE 0552 *and* EPRG 08.Parry, I., and W.E. Oates. 2000. Policy Analysis in the Presence of Distorting Taxes. *Journal of Policy Analysis and Management* 19:603-614.

Paltsev, S., Reilly, J., Jacoby H., Gurgel, A., Metcalf, G., Sokolov, A., and J. Holak, 2007. Assessment of U.S. Cap-and-Trade Proposals. *MIT Joint Program on the Science and Policy of Global Change*. Report No. 146.

Schneider, S.H., and L.H. Goulder, 1997. *Achieving low-cost emissions targets.* Nature 389, September.

FMPA-POD1-00155

HEARING EXHIBIT - 00000318

EPA Analysis of the Lieberman-Warner Climate Security Act of 2008

S. 2191 in 110th Congress

Appendix

March 14, 2008

FMPA-POD1-00156

HEARING EXHIBIT - 00000319

Appendix 1: Modeling Approach and Limitations

FMPA-POD1-00157

HEARING EXHIBIT - 00000320

EPA Models Used for Different Analytical Scenarios

Table: Models Used for Different Scenarios

1) EPA Reference				
	ADAGE	IGEM	IPM	MiniCAM
2) S. 2191				
	ADAGE	IGEM	IPM	MiniCAM	NCGM/FASOM/GTM/MiniCAM Offset Spreadsheet Tool
3) S. 2191 with Low International Actions				
	ADAGE				NCGM/FASOM/GTM/MiniCAM Offset Spreadsheet Tool
4) S. 2191 Unlimited Offsets				
		IGEM			NCGM/FASOM/GTM/MiniCAM Offset Spreadsheet Tool
5) S. 2191 *No Offsets*				
		IGEM		
6) S. 2191 Constrained Nuclear & Biomass				
	ADAGE			
7) S. 2191 Constrained Nuclear & Biomass, and CCS				
	ADAGE			
8) S. 2191 Constrained Nuclear & Biomass + Beyond Kyoto + Natural Gas Cartel				
	ADAGE			
9) Alternative Reference				
	ADAGE	IGEM	IPM	
10) S. 2191 Alternative Reference				
	ADAGE	IGEM	IPM		NCGM/FASOM/GTM/MiniCAM Offset Spreadsheet Tool

ADAGE	Applied Dynamic Analysis of the Global Economy (Ross, 2007)
IGEM	Intertemporal General Equilibrium Model (Jorgenson, 2007)
IPM	Integrated Planning Model (EPA, 2007)
NCGM	EPA's non-CO_2 GHG spreadsheet tools for estimating projections and mitigation of CH_4, N_2O, and F-gases (EPA, 2005)
FASOMGHG	Forest and Agriculture Sector Optimization Model, GHG version (EPA, 2005)
GTM	Global Timber Model (Sohngen, 2006)
MiniCAM	Mini-Climate Assessment Model (Edmonds, 2005)

Note: International allowance and domestic offset markets were analyzed using EPA's spreadsheet tool which combines results from the NCGM, FASOM, GTM and MiniCAM models.

FMPA-POD1-00158

HEARING EXHIBIT - 00000321

Modeling Approach

- For the purpose of this analysis, we have chosen to use two separate computable general equilibrium (CGE) models: IGEM and ADAGE.
- CGE models are structural models.
  - They build up their representation of the whole economy through the interactions of multiple agents (e.g. households and firms), whose decisions are based upon optimizing economic behavior.
  - The models simulate a market economy, where in response to a new policy, prices and quantities adjust so that all markets clear.
- These models are best suited for capturing long-run equilibrium responses, and unique characteristics of specific sectors of the economy.
- The general equilibrium framework of these models allows us to examine both the direct and indirect economic effects of the proposed legislation, as well as the dynamics of how the economy adjusts in the long run in response to S. 2191.
- The NCGM, FASOM, GTM, and MiniCAM models are used to provide information on abatement options that fall outside of the scope of the CGE models.
  - These models generate mitigation cost schedules for various abatement options.
- Additionally, the IPM model gives a detailed picture of the electricity sector in the short-run (through 2025), which complements the long-run (through 2050) equilibrium response represented in the CGE models.

FMPA-POD1-00159

HEARING EXHIBIT - 00000322

Modeling Approach (con't)

Several updates were made in the S. 1766 analysis as compared with the S. 280 analysis. These updates have also been included in the S. 2191 analysis:

- Assumptions
  - The renewables assumptions in ADAGE were updated in the S. 1766 analysis to include a biomass response curve for electricity generation from the FASOM model. These updated assumptions are also used in the S. 2191 analysis.
- Results reported
  - As in the S. 1766 analysis, we are reporting regional impacts form the ADAGE model in the S. 2191 analysis.
  - As in the S. 1766 analysis, we are also reporting international leakage from ADAGE in the S. 2191 analysis.

FMPA-POD1-00160

HEARING EXHIBIT - 00000323

Modeling Limitations

- The models used in this analysis do not formally represent uncertainty.
  - Confidence intervals cannot be presented for any of the results in this analysis.
  - Very few CGE models are capable of computing confidence intervals, so this limitation is currently shared with virtually all CGE models.
  - The use of two CGE models provides a range for many of the key results of this analysis; however, this range should not be interpreted as a confidence interval.
  - Alternate scenarios are presented to provided sensitivities on a few of the key determinants of the modeled costs of S. 2191.
- The CGE modeling approach generally does not allow for a detailed representation of technologies.
  - While ADAGE does represent different generation technologies within the electricity sector, it does not represent peak and base load generation requirements.
  - Since the electricity sector plays a vital role in the abatement of CO_2 emissions, we have supplemented the results from our CGE models with results from the Integrated Planning Model (IPM), which is bottom-up model of the electricity sector.
  - The CGE models do not explicitly model new developments in transportation technologies. These reductions occur as households alter their demand for motor gasoline and through broad representations of improvements in motor vehicle fuel efficiency.
- The time horizon of the CGE models, while long from an economic perspective, is short from a climate perspective.
- CGE models represent emissions of GHGs, but cannot capture the impact that changes in emissions have on global GHG concentrations.
  - In order to provide information on how S. 2191 affects CO_2 concentrations throughout the 21st century, we have used the Mini-Climate Assessment Model (MiniCAM) to supplement our results.
- None of the models used in this analysis currently represent the benefits of GHG abatement.
  - While the models do not represent benefits, it can be said that as the abatement of GHG emissions increases over time, so do the benefits of the abatement.

FMPA-POD1-00161

HEARING EXHIBIT - 00000324

Modeling Limitations (con't)

- The models used in this analysis do not incorporate benefit-side effects of reductions in conventional pollutants (SO_2, NOx, and Hg) , such as labor productivity improvements from gains in public health.
  - While this is an important limitation of the models, the impact on modeled costs of the policy is small because S. 2191 does not impact overall emissions of conventional pollutants covered by existing cap and trade programs due to the existence caps which instead allow allowance prices for conventional pollutants to fall.
- The costs of administering S. 2191 (e.g. monitoring and enforcement) are not captured in this analysis.
- Household effects are not disaggregated.
- Both of the CGE models used in this analysis are full employment models.
  - The models do not represent effects on unemployment.
  - The models do represent the choice between labor and leisure, and thus labor supply changes are represented in the models.
- While ADAGE does include capital adjustment costs, capital in IGEM moves without cost.
- IGEM is a domestic model; ADAGE has the capability of representing regions outside of the U.S., which were used to incorporate interactions between the U.S. and Group 1 & 2 countries. For consistency across analyses, international abatement options were generated in the following fashion:
  - We used the MiniCAM model to generate the supply and demand of GHG emissions abatement internationally.
  - For Group 2 countries that are assumed to not have a cap on GHG emissions before 2025, and thus supply mitigation only through certified emissions reductions resulting from project activities, the potential energy related CO_2 mitigation supply is reduced by 90% though 2015, and by 75% between 2015 and 2025.
  - Combining the international demand for abatement from MiniCAM, the domestic demand for offsets determined by the 30% limit on offsets, and the mitigation cost schedules for the various sources of offsets generated by the NCGM, FASOM, GTM, and MiniCAM models, allows us to find market equilibrium price and quantity of offsets and international credits.

FMPA-POD1-00162

HEARING EXHIBIT - 00000325

Modeling Limitations (con't)

- Since international abatement occurs outside of IGEM, the model does not capture emissions leakage.*
  - Since IGEM is a domestic model, world prices are not affected by climate policies in Group 1 and Group 2 countries. As a result of S. 2191, the prices of U.S. exports rise relative to prices in the rest of the world, and export volumes fall. Since exports are price-elastic the volumes fall proportionally more than the price rises and thus the value of exports declines. Imports are reduced in part by the overall reduction in spending associated with the lower levels of consumption. Additionally, commodities directly affected by the emissions cap (e.g. oil) are reduced proportionally more than other imports due to the allowance prices embodied in their cost. Import substitution counterbalances the two forces above. U.S. prices of commodities not directly affected by the policy are relatively higher, which leads to substitution away from domestically produced goods and towards imported goods. To the extent that policies in Group 1 and Group 2 countries increase world prices of affected commodities, the relative price difference between goods produced in the U.S. and goods produced abroad will be lessened. This will reduce impact on exports, and reduce the import substitution effect, both of which are driven by the relative price differential.
- ADAGE is a global model which does represent the emissions leakage associated with S. 2191.
  - The assumed climate policies in Group 1 and Group 2 countries are explicitly represented in ADAGE, and thus affect world prices. As a result the relative price differences between goods produced domestically and abroad are smaller than the differences in IGEM, and thus the relative price driven changes in imports and exports are smaller in ADAGE than in IGEM.

* Emissions leakage occurs when a domestic GHG policy causes a relative price differential between domestically produced and imported goods. This causes domestic production, which embodies the GHG allowance price to shift abroad, and thus an increase in GHG emissions in other countries. Additionally, emissions leakage not associated with trade effects may occur when a GHG policy reduces domestic consumption of oil, lower demand for oil lowers the world oil price, which increases oil consumption in countries without a GHG policy thus increasing emissions.

FMPA-POD1-00163
HEARING EXHIBIT - 00000326

Modeling Limitations (con't)

S. 2191 Title III – Allocating and Distributing Allowances

- Not all of the specified uses of allocated allowances are explicitly modeled.
  - Explicitly modeled:
    - CCS Bonus allowances specified in *Title III – Subtitle F – Bonus Allowances for Carbon Capture and Geological Sequestration.*
    - Emissions reductions associated with allowance set-asides in *Title III – Subtitle G – Domestic Agriculture and Forestry*
    - Emissions reductions associated with allowance set-asides in *Title III – Subtitle J – Reducing Methane Emissions From Landfills and Coal Mines.*
  - Not explicitly modeled (although the value of allowances allocated for each of these purposes is reported):
    - Allocation for early action specified in *Title III – Subtitle B – Early Action*
    - Allocation to states for energy savings and programs that exceed federal emissions reductions targets specified in *Title III – Subtitle C - States.*
    - Allocation to load serving entities for the purpose of energy efficiency programs and mitigation of impacts on low and middle-income energy consumers specified in *Title III – Subtitle D – Electricity Consumers.*
    - Allocation to natural gas distributors for the purpose of energy efficiency programs and mitigation of impacts on low and middle-income energy consumers specified in *Title III – Subtitle E – Natural Gas Consumers.*
    - Allocation to for use in carrying out forest carbon activities in countries other than the United States specified in *Title III – Subtitle H – International Forest Protection.*
    - Allocation to fossil fuel-fired electric power generating facilities, rural electric power cooperatives, owners and operators of energy intensive manufacturing facilities, facilities that produce or import petroleum based fuels, and HFC producers and importers specified in *Title III – Subtitle I – Transition Assistance.*
- While not all of the uses of allocated allowances are explicitly modeled, the value of allowances allocated for each of the specified uses is reported.

FMPA-POD1-00164

HEARING EXHIBIT - 00000327

Modeling Limitations (con't)

S. 2191 Title IV – Auctions and Uses of Auction Proceeds

- The specified uses of the revenues associated with auctioned allowances are not explicitly modeled. Sections of note that are not modeled include:
  - *Title IV – Subtitle C – Auctions* (such percentage that the Administrator deems sufficient may be used for the efficient and effective administration of this act)
  - *Title IV – Subtitle D – Energy Technology Deployment* (52% of remaining auction revenues)
    - *Sec. 4402. Zero- or Low-Carbon Energy Technologies Deployment* (32% *Title IV - Subtitle D* funds)
    - *Sec. 4403. Advanced Coal and Sequestration Technologies Program* (25% *Title IV - Subtitle D* funds)
    - *Sec. 4404. Fuel from Cellulosic Biomass* (6% *Title IV - Subtitle D* funds)
    - *Sec. 4405. Advanced Technologies Vehicle Manufacturing Incentive Program* (12% *Title IV - Subtitle D* funds)
    - *Sec. 4406. Sustainable Energy Program* (25% *Title IV - Subtitle D* funds)
  - *Title IV – Subtitle E – Energy Consumers* (18% of remaining auction revenues)
  - *Title IV – Subtitle F – Climate Change Worker Training Program* (5% of remaining auction revenues)
  - *Title IV – Subtitle G – Adaptation for Natural Resources in the U.S. and Territories* (18% of remaining auction revenues)
  - *Title IV – Subtitle H – International Climate Change Adaptation and National Security Program* (5% of remaining auction revenues)
  - *Title IV – Subtitle I – Emergency Firefighting Program* ($1.2 billion annually)
  - *Energy Independence Acceleration Fund* (2% or remaining auction revenues)
- While the uses of the auction revenues are not modeled, the amount of auction revenue available for each of these purposes is reported.

FMPA-POD1-00165

HEARING EXHIBIT - 00000328

Modeling Limitations (con't)

S. 2191 Title III – Allocating and Distributing Allowances and Title IV – Auctions and Uses of Auction Proceeds

- In IGEM we assume that the policy is deficit and revenue neutral, which implies that the market outcomes are invariant to the auction / allocation spilt
  - Allowance auction revenues flow to the U.S. government, and are redistributed to households lump sum to the extent that deficit and spending levels are maintained. If auction revenues were directed to special funds instead of returned directly to households as modeled, the reduction in household annual consumption and GDP would likely be greater. If the auction revenues were instead used to lower distortionary taxes, the costs of the policy would be lower.
  - Private sector revenues from allocated allowances accrue to employee-shareholder households, and the government adjusts taxes lump sum to maintain deficit and spending levels.
- The use of the revenue generated by auctioning permits can affect the cost of the policy.
- Compared to returning auction revenues to consumers in a lump sum fashion that maintains revenue and deficit neutrality, other uses of auction revenues for other purposes can positively or negatively impact the cost of the policy.
  - Using auction revenues to lower distortionary taxes can lower the cost of the policy.
    - This possibility is known as the "double dividend" and has been widely discussed in the economics literature (e.g. Goulder et al. 1999, Parry et al. 1999, Parry and Oates 2000, and Parry and Bento 2000, CBO 2007).
    - One study (Parry and Bento 2000) finds that different methods of revenue recycling under a cap-and-trade system that reduces emissions by 10 percent can lead to economy-wide costs that differ by a factor of three.
  - Directing auction revenues to special funds or creating subsidies to specific technologies can raise the overall costs of a policy due to the need to finance these policies with increases in distortionary taxes (the converse of the "double dividend" benefit of reducing distortionary taxes discussed above).
    - However, substantial cost savings could be achieved by combining direct emissions policies (e.g. cap-and-trade or carbon tax) with technology push policies (e.g. technology and R&D incentives) that correct for the market failure associated with the fact that the inventor of a new technology can not appropriate all of the associated social benefits (Fischer and Newell 2005; Schneider and Goulder 1997).

FMPA-POD1-00166
HEARING EXHIBIT - 00000329

Modeling Limitations (con't)

S. 2191 Title V – Energy Efficiency and Title II – Subtitle F – Carbon Market Efficiency Board

- The energy efficiency standards specified in *Title V – Subtitle A – Appliance Efficiency* and *Title V – Subtitle B – Building Efficiency* are not included in this analysis.
- The Carbon Market Efficiency Board (CMEB), established under *Title II – Managing and Containing Costs Efficiently – Subtitle F – Carbon Market Efficiency Board* is not explicitly modeled in this analysis.
  - Several of the powers of the CMEB involve expanding or altering the provisions for borrowing allowances (*Sec. 2604 – Powers – (a)(1)(A),(B),(C),* and *(F)*). The models used for this analysis make a standard economic assumption of perfect foresight, and as a result the price of allowances rise at a predictable rate without any volatility. Without any allowance price volatility, firms bank allowances in the early years and draw down that bank in the later years without any need for borrowing; hence, an expansion of the borrowing provisions would not affect firms in the models used in this analysis. In the absence of perfect information, price volatility would likely lead to the use of borrowing in some years, and the CMEB's powers to alter the terms of borrowing would affect the amount of borrowing and thus the amount of price volatility.
  - The CMEB also is granted the power to increase the quantity of allowances that may be obtained from foreign GHG emissions trading markets (*Sec. 2604 – Powers – (a)(1)(D)*) and domestic offset markets (*Sec. 2604 – Powers – (a)(1)(E)*). While this is not explicitly modeled in this analysis; two alternative scenarios do explore the affects of allowing unlimited offsets and allowing no offsets. These alternative scenarios show the maximum extent that altering the offset and international credit limitations can affect costs, given a specific set of assumptions about international actions to reduce GHG emissions.

FMPA-POD1-00167

HEARING EXHIBIT - 00000330

Modeling Limitations (con't)

Title II – Subtitle D – Sections 2402 & 2404 (Offsets Discounting)

- There are sections within Title II - Subtitle D of S. 2191 that deal with discounting offsets.
  - Title II - Subtitle D - Section 2402 (b)(3)(D) requires that regulations promulgated to authorize the issuance and certification of offset allowances shall include provisions that, "establish procedures to monitor, quantify, and discount reductions in greenhouse gas emissions or increases in biological sequestration in accordance with subsections (d) through (g) of section 2404."
  - Title II - Subtitle D - Section 2404 (g)(3) states the minimum requirements for the standardized methods for determining the discount for leakage.
  - Title II - Subtitle D - Section 2404 (h) requires the development of standardized methods for use in determining and discounting for uncertainty for each offset project type.
- The discounting of offsets has the potential to raise the price of offsets, which would increase the costs of implementing S. 2191.
- However, none of these provisions provide enough detail about how offsets would be discounted for us to include them in our economic modeling of S. 2191.
- Furthermore, because the 15% limit on the use of offsets is a binding constraint in our analysis, any small change in the offset supply curves due to discounting would have a negligible impact on the analysis outside of the offset market (i.e. the offset price would increase and offset payments would increase, but the allowance price would remain unchanged, and the economy wide economic impacts would be essentially the same).
  - However, if the discounting were great enough to significantly change the offset supply curves to the point that the 15% limit on the use of offsets were no longer binding, then allowance prices would be expected to rise, and the economy wide impacts would increase.

FMPA-POD1-00168

HEARING EXHIBIT - 00000331

Appendix 2: Scenario Comparison Tables

FMPA-POD1-00169

HEARING EXHIBIT - 00000332

Analytical Scenarios (con't)

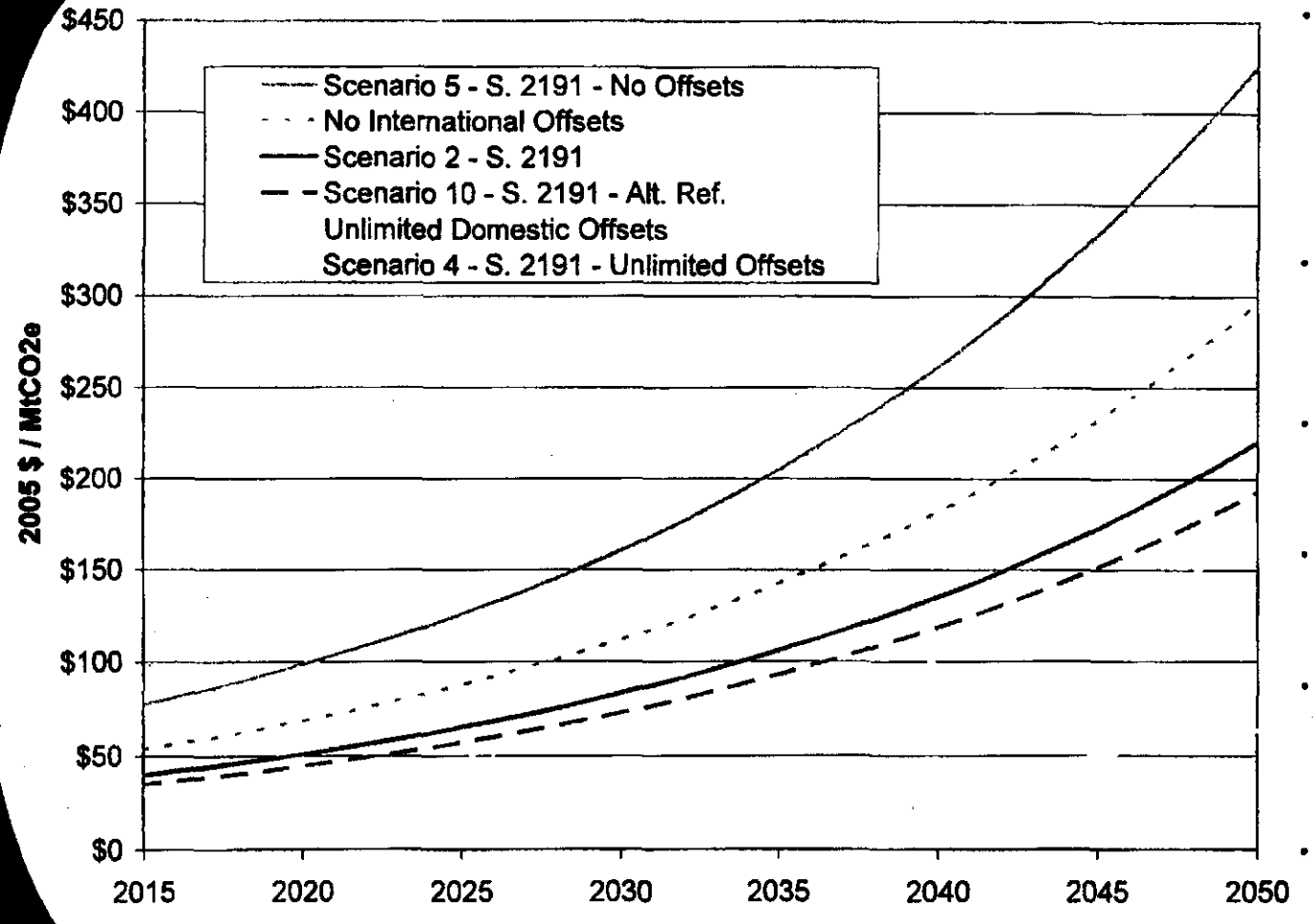
Table: Scenario Definitions

	Ref	International Action	Domestic Offsets	International Offsets	Biomass	CCS	Nuclear	Natural Gas Cartel
1) EPA Reference	Standard	None	n/a	n/a	Ref	n/a	Ref	No
2) S. 2191	Standard	MIT	15%	15%	Unrestricted	Unrestricted	150% Increase	No
3) S. 2191 with Low International Actions	Standard	Alternative	15%	15%	Unrestricted	Unrestricted	150% Increase	No
4) S. 2191 Unlimited Offsets	Standard	MIT	Unlimited	Unlimited	Unrestricted	Unrestricted	150% Increase	No
5) S. 2191 No Offsets	Standard	MIT	None	None	Unrestricted	Unrestricted	150% Increase	No
6) S. 2191 Constrained Nuclear & Biomass	Standard	MIT	15%	15%	Ref	Unrestricted	Ref	No
7) S. 2191 Constrained Nuclear & Biomass, and CCS	Standard	MIT	15%	15%	Ref	After 2030	Ref	No
8) S. 2191 Constrained Nuclear & Biomass + Beyond Kyoto + Natural Gas Cartel	Standard	Inhofe	15%	15%	Ref	After 2030	Ref	No
9) Alternative Reference	High Tech	None	n/a	n/a	High Tech Ref	n/a	High Tech Ref	No
10) S. 2191 Alternative Reference	High Tech	MIT	15%	15%	Unrestricted	Unrestricted	150% Increase	No

FMPA-POD1-00170
HEARING EXHIBIT - 00000333

Scenario Comparison

GHG Allowance Prices (IGEM)



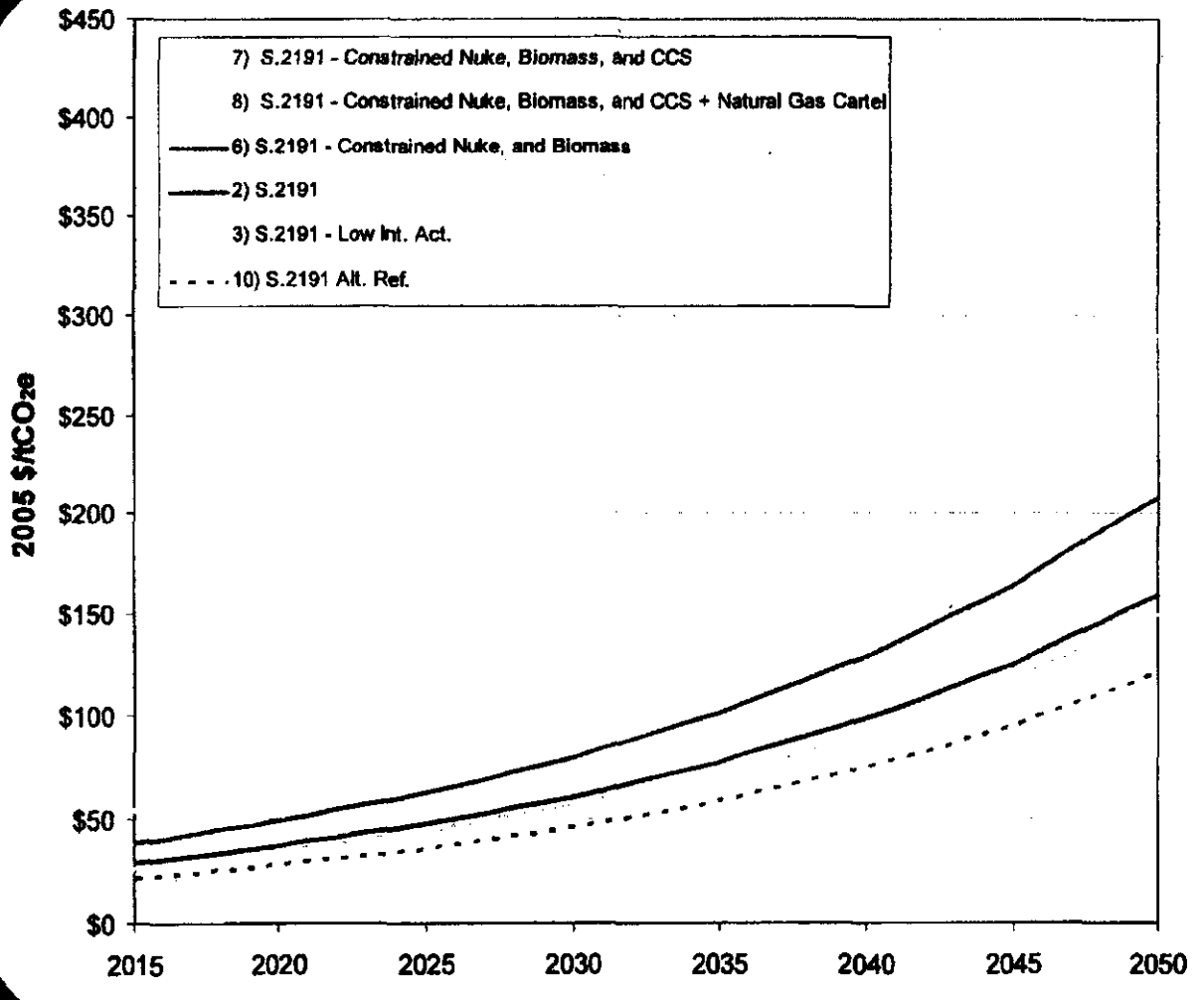
- Compared to the variation in allowance prices between the various alternative technology scenarios, there is a greater variation in allowance prices amongst the alternative offset and international credit scenarios.
- Allowing the unlimited use of domestic offsets and international credits can reduce allowance prices by 71% compared to scenario 2.
- Allowing the unlimited use of just domestic offsets can reduce allowance prices by 26% compared to scenario 2.
- If international credits are not allowed, allowance prices increase by 34% compared to scenario 2.
- If both international credits and domestic offsets are not allowed, allowance prices increase by 93% compared to scenario 2.
- Allowance prices are 12% lower under the alternative reference case compared to scenario 2.

FMPA-POD1-00171

HEARING EXHIBIT - 00000334

Scenario Comparison

GHG Allowance Prices (ADAGE)



- Compared to the variation in allowance prices between the various alternative offset and international credit scenarios, there is a smaller variation in allowance prices amongst the alternative technology scenarios.
- Allowance prices are 86% higher in the constrained nuclear, biomass, and CCS scenario compared to scenario 2. The natural gas cartel has minimal influence on the allowance price.
- Allowance prices are 32% higher in the constrained nuclear, and biomass scenario compared to scenario 2.
- Allowance prices are 24% lower under the alternative reference case compared to scenario 2.

FMPA-POD1-00172

HEARING EXHIBIT - 00000335

Scenario Comparison

GHG Allowance Prices

Table: Allowance Price Comparison (2005 $/tCO2e)

	2015	2020	2025	2030	2035	2040	2045	2050
1) EPA Reference								
ADAGE	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2) S. 2191								
ADAGE	$29	$37	$48	$61	$77	$98	$125	$159
IGEM	$40	$51	$65	$83	$106	$135	$173	$220
3) S.2191 w/ Low International Action								
ADAGE	$27	$35	$44	$56	$72	$92	$117	$149
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
4) S.2191 w/ Unlimited Offsets								
ADAGE	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
IGEM	$11	$15	$19	$24	$30	$39	$50	$63
5) S.2191 w/ No Offsets								
ADAGE	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
IGEM	$77	$98	$126	$160	$205	$261	$333	$425
6) S.2191 Constrained Nuclear & Biomass								
ADAGE	$39	$49	$63	$80	$101	$129	$164	$208
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
7) S.2191 Constrained Nuclear & Biomass, and CCS								
ADAGE	$55	$69	$88	$112	$142	$181	$229	$290
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
8) S.2191 Constrained Nuclear & Biomass, and CCS + Beyond Kyoto + Natural Gas Cartel								
ADAGE	$55	$70	$88	$112	$142	$180	$228	$288
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
9) Alternative Reference								
ADAGE	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
10) S.2191 Alt. Ref.								
ADAGE	$22	$28	$36	$46	$59	$75	$95	$121
IGEM	$35	$45	$57	$73	$93	$118	$151	$193

FMPA-POD1-00173

HEARING EXHIBIT - 00000336

Scenario Comparison

GDP Impacts

(Percentage Change from Reference)

Table: GDP Comparisons (% Change from Reference)

	2015	2020	2025	2030	2035	2040	2045	2050
1) EPA Reference								
ADAGE	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2) S. 2191								
ADAGE	-0.7%	-0.7%	-0.7%	-0.9%	-1.1%	-1.4%	-1.9%	-2.4%
IGEM	-2.0%	-2.6%	-3.1%	-3.8%	-4.4%	-5.2%	-6.0%	-6.9%
3) S. 2191 with Low International Actions								
ADAGE	-0.6%	-0.7%	-0.9%	-1.1%	-1.3%	-1.6%	-2.0%	-2.5%
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
4) S. 2191 Unlimited Offsets								
ADAGE	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
IGEM	-0.7%	-0.9%	-1.1%	-1.3%	-1.6%	-1.9%	-2.3%	-2.7%
5) S. 2191 No Offsets								
ADAGE	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
IGEM	-3.3%	-4.1%	-5.0%	-5.9%	-6.9%	-7.9%	-9.0%	-10.1%
6) S. 2191 Constrained Nuclear & Biomass								
ADAGE	-0.8%	-0.9%	-0.9%	-1.2%	-1.6%	-2.0%	-2.6%	-3.3%
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
7) S. 2191 Constrained Nuclear & Biomass, and CCS								
ADAGE	-1.1%	-1.5%	-1.8%	-2.3%	-2.6%	-3.1%	-3.8%	-4.4%
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
8) S. 2191 Constrained Nuclear & Biomass + Beyond Kyoto + Natural Gas Cartel								
ADAGE	-1.1%	-1.4%	-1.6%	-2.1%	-2.4%	-2.9%	-3.6%	-4.3%
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
9) Alternative Reference								
ADAGE	0.1%	0.3%	0.3%	0.3%	0.2%	0.2%	0.1%	0.1%
IGEM	0.3%	0.2%	0.1%	-0.2%	-0.2%	-0.3%	-0.3%	-0.3%
10) S. 2191 Alternative Reference								
ADAGE	-0.3%	-0.2%	-0.2%	-0.3%	-0.5%	-0.9%	-1.2%	-1.6%
IGEM	-1.5%	-2.1%	-2.6%	-3.3%	-4.0%	-4.7%	-5.5%	-6.4%

FMPA-POD1-00174

HEARING EXHIBIT - 00000337

Scenario Comparison

GDP Impacts

(Billion 2005$, Change from Reference)

Table: GDP Comparisons (Billion 2005 $ Change from Reference)

	2015	2020	2025	2030	2035	2040	2045	2050
1) EPA Reference								
ADAGE	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2) S. 2191								
ADAGE	-$110	-$137	-$162	-$238	-$322	-$488	-$711	-$1,012
IGEM	-$340	-$506	-$715	-$983	-$1,326	-$1,752	-$2,258	-$2,856
3) S. 2191 with Low International Actions								
ADAGE	-$108	-$148	-$210	-$300	-$393	-$555	-$767	-$1,049
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
4) S. 2191 Unlimited Offsets								
ADAGE	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
IGEM	-$111	-$173	-$250	-$359	-$486	-$654	-$865	-$1,134
5) S. 2191 No Offsets								
ADAGE	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
IGEM	-$557	-$820	-$1,142	-$1,542	-$2,049	-$2,657	-$3,365	-$4,185
6) S. 2191 Constrained Nuclear & Biomass								
ADAGE	-$141	-$170	-$212	-$323	-$479	-$672	-$883	-$1,390
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
7) S. 2191 Constrained Nuclear & Biomass, and CCS								
ADAGE	-$191	-$293	-$404	-$603	-$776	-$1,052	-$1,359	-$1,892
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
8) S. 2191 Constrained Nuclear & Biomass + Beyond Kyoto + Natural Gas Cartel								
ADAGE	-$188	-$276	-$370	-$568	-$724	-$991	-$1,293	-$1,835
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
9) Alternative Reference								
ADAGE	$24	$54	$64	$71	$67	$61	$55	$51
IGEM	$50	$49	$17	-$47	-$74	-$87	-$98	-$106
10) S. 2191 Alternative Reference								
ADAGE	-$58	-$45	-$45	-$88	-$158	-$292	-$483	-$703
IGEM	-$262	-$417	-$638	-$947	-$1,292	-$1,700	-$2,179	-$2,747

FMPA-POD1-00175

HEARING EXHIBIT - 00000338

Scenario Comparison

Consumption Impacts
(Percentage Change from Reference)

Table: Consumption Comparisons (% Change from Reference)

	2015	2020	2025	2030	2035	2040	2045	2050
1) EPA Reference								
ADAGE	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2) S. 2191								
ADAGE	-0.3%	-0.4%	-0.6%	-0.9%	-1.1%	-1.4%	-1.7%	-2.1%
IGEM	-0.2%	-0.7%	-1.1%	-1.4%	-1.9%	-2.3%	-2.7%	-3.3%
3) S. 2191 with Low International Actions								
ADAGE	-0.6%	-0.7%	-0.9%	-1.1%	-1.1%	-1.3%	-1.5%	-1.7%
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
4) S. 2191 Unlimited Offsets								
ADAGE	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
IGEM	0.0%	-0.2%	-0.4%	-0.5%	-0.7%	-0.8%	-1.0%	-1.2%
5) S. 2191 No Offsets								
ADAGE	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
IGEM	-0.3%	-1.2%	-1.8%	-2.5%	-3.2%	-3.9%	-4.5%	-5.3%
6) S. 2191 Constrained Nuclear & Biomass								
ADAGE	-0.5%	-0.7%	-1.0%	-1.4%	-1.7%	-1.9%	-2.3%	-2.8%
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
7) S. 2191 Constrained Nuclear & Biomass, and CCS								
ADAGE	-0.6%	-1.0%	-1.4%	-1.9%	-2.5%	-3.1%	-3.8%	-4.2%
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
8) S. 2191 Constrained Nuclear & B + Beyond Kyoto + Natural Gas Cartel								
ADAGE	-0.6%	-0.9%	-1.3%	-1.8%	-2.4%	-3.2%	-4.0%	-4.4%
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
9) Alternative Reference								
ADAGE	0.1%	0.1%	0.2%	0.2%	0.2%	0.1%	0.1%	0.1%
IGEM	0.1%	0.1%	0.0%	-0.1%	-0.2%	-0.2%	-0.2%	-0.3%
10) S. 2191 Alternative Reference								
ADAGE	-0.1%	-0.2%	-0.4%	-0.6%	-0.8%	-1.1%	9.7%	-1.7%
IGEM	-0.1%	-0.5%	-0.9%	-1.3%	-1.8%	-2.3%	-2.7%	-3.2%

FMPA-POD1-00176

HEARING EXHIBIT - 00000339

Scenario Comparison

Consumption Impacts
(Billion 2005$, Change from Reference)

Table: Consumption Comparisons (Billion 2005 $ Change from Reference)

	2015	2020	2025	2030	2035	2040	2045	2050
1) EPA Reference								
ADAGE	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2) S. 2191								
ADAGE	-$37	-$63	-$104	-$180	-$243	-$353	-$488	-$670
IGEM	-$19	-$82	-$149	-$233	-$346	-$478	-$641	-$843
3) S. 2191 with Low International Actions								
ADAGE	-$71	-$107	-$153	-$216	-$258	-$330	-$418	-$536
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
4) S. 2191 Unlimited Offsets								
[redacted]GE	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
[redacted]EM	-$4	-$25	-$51	-$81	-$124	-$173	-$237	-$318
5) S. 2191 No Offsets								
ADAGE	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
IGEM	-$33	-$144	-$262	-$404	-$591	-$806	-$1,062	-$1,369
6) S. 2191 Constrained Nuclear & Biomass								
ADAGE	-$68	-$109	-$167	-$268	-$378	-$476	-$667	-$908
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
7) S. 2191 Constrained Nuclear & Biomass, and CCS								
ADAGE	-$94	-$152	-$236	-$374	-$555	-$791	-$1,093	-$1,336
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
8) S. 2191 Constrained Nuclear & B + Beyond Kyoto + Natural Gas Cartel								
ADAGE	-$66	-$120	-$203	-$349	-$543	-$799	-$1,129	-$1,410
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
9) Alternative Reference								
ADAGE	$16	$36	$39	$40	$36	$32	$29	$27
IGEM	$6	$9	$3	-$11	-$32	-$47	-$57	-$66
10) S. 2191 Alternative Reference								
ADAGE	-$19	-$34	-$61	-$118	-$182	-$285	$2,761	-$542
IGEM	-$7	-$61	-$126	-$215	-$337	-$471	-$630	-$820

FMPA-POD1-00177

HEARING EXHIBIT - 00000340

Scenario Comparison

Total U.S. GHG Emissions ($MtCO_2e$)

Table: Total U.S. Greenhouse Gas Emissions

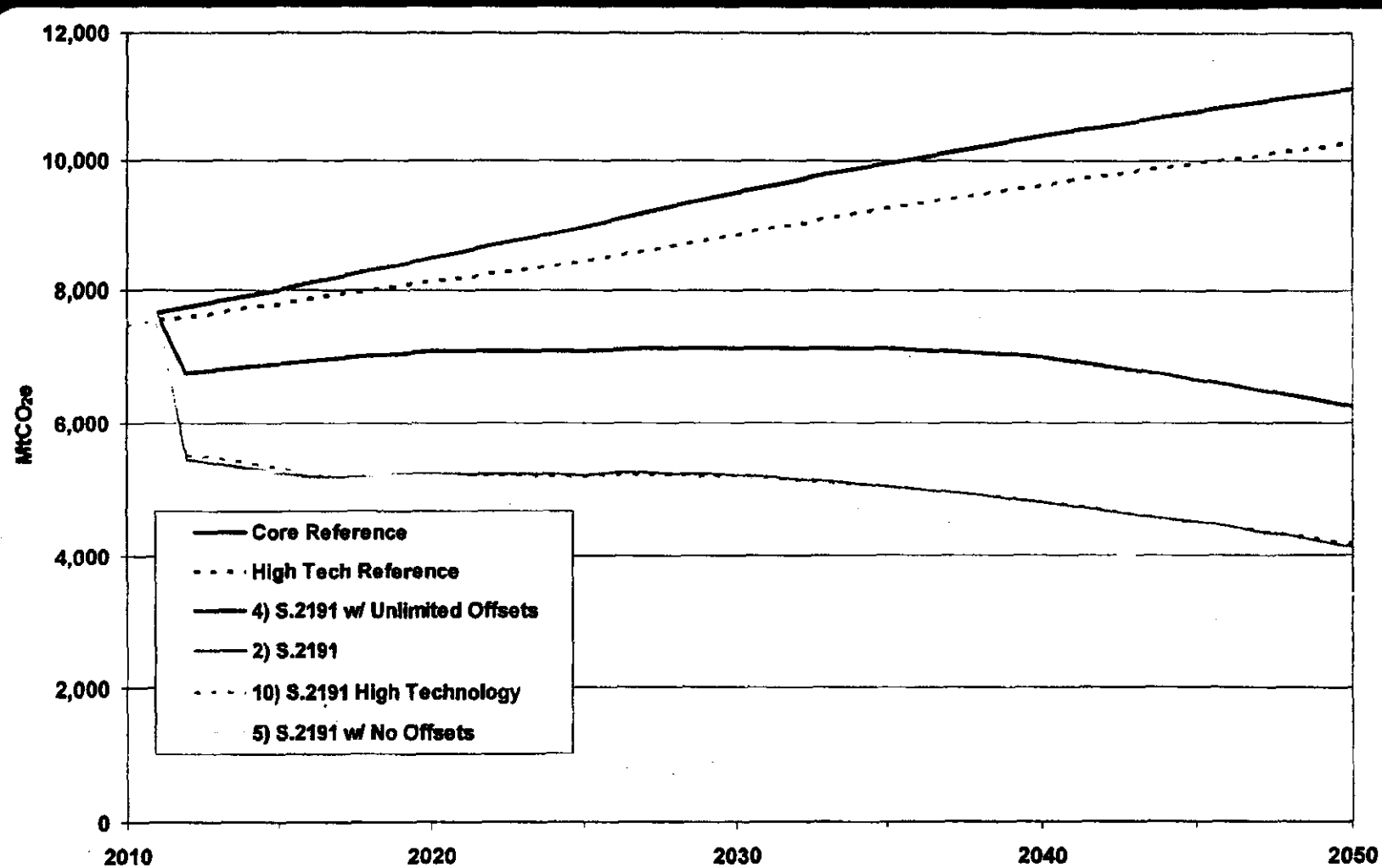
	2015	2020	2025	2030	2035	2040	2045	2050
1) EPA Reference								
ADAGE	7,830	8,264	8,626	9,089	9,452	9,786	10,068	10,312
IGEM	8,011	8,494	8,958	9,493	9,954	10,370	10,765	11,148
2) S. 2191								
ADAGE	6,362	6,368	6,201	5,867	5,439	5,424	5,362	5,279
IGEM	5,249	5,236	5,217	5,217	5,048	4,801	4,496	4,121
3) S. 2191 with Low International Actions								
ADAGE	6,409	6,453	6,198	5,852	5,405	5,379	5,334	5,239
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
4) S. 2191 Unlimited Offsets								
ADAGE	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
IGEM	6,900	7,079	7,088	7,124	7,127	7,005	6,671	6,253
5) S. 2191 No Offsets								
ADAGE	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
IGEM	5,267	5,205	5,047	4,924	4,629	4,237	3,806	3,395
6) S. 2191 Constrained Nuclear & Biomass								
ADAGE	6,244	6,298	6,218	5,996	5,580	5,430	5,368	5,260
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
7) S. 2191 Constrained Nuclear & Biomass, and CCS								
ADAGE	5,949	6,061	6,120	6,176	6,044	5,816	5,409	4,946
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
8) S. 2191 Constrained Nuclear & Biomass + Beyond Kyoto + Natural Gas Cartel								
ADAGE	5,955	6,068	6,143	6,201	6,076	5,852	5,445	4,984
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
9) Alternative Reference								
ADAGE	7,618	7,896	8,121	8,442	8,779	9,068	9,349	9,576
IGEM	7,804	8,129	8,451	8,850	9,255	9,615	9,953	10,279
10) S. 2191 Alternative Reference								
ADAGE	6,347	6,256	6,176	5,953	5,568	5,321	5,316	5,263
IGEM	5,316	5,221	5,183	5,185	5,035	4,898	4,490	4,178

FMPA-POD1-00178

HEARING EXHIBIT - 00000341

Scenario Comparison

Total U.S. GHG Emissions ($MtCO_2e$) (IGEM)



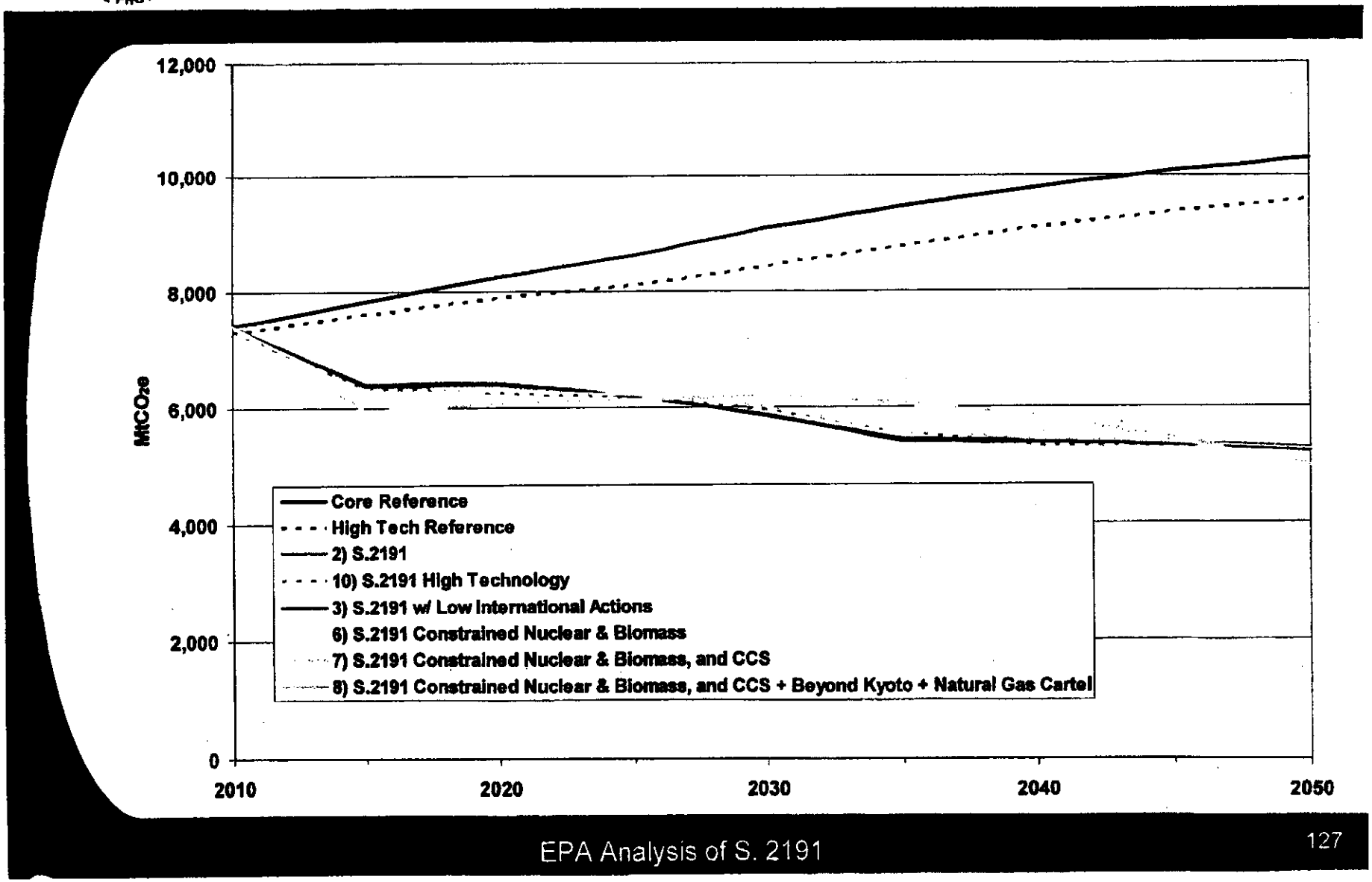
EPA Analysis of S. 2191

FMPA-POD1-00179

HEARING EXHIBIT - 00000342

Scenario Comparison

Total U.S. GHG Emissions ($MtCO_2e$) (ADAGE)



EPA Analysis of S. 2191

FMPA-POD1-00180

HEARING EXHIBIT - 00000343

Scenario Comparison

Covered GHG Emissions – Offsets ($MtCO_2e$)

Table: Covered GHG Emissions - Offsets

	2015	2020	2025	2030	2035	2040	2045	2050
1) EPA Reference								
ADAGE	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2) S. 2191								
ADAGE	4,378	4,112	3,963	3,706	3,395	3,401	3,374	3,329
IGEM	4,124	4,073	4,014	3,971	3,771	3,510	3,207	2,845
3) S. 2191 with Low International Actions								
ADAGE	4,424	4,155	3,968	3,702	3,372	3,369	3,361	3,307
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
4) S. 2191 Unlimited Offsets								
ADAGE	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
IGEM	4,952	4,634	4,320	4,029	3,561	3,054	2,486	1,921
5) S. 2191 No Offsets								
ADAGE	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
IGEM	4,434	4,358	4,182	4,042	3,717	3,304	2,862	2,442
6) S. 2191 Constrained Nuclear & Biomass								
ADAGE	4,264	4,025	3,954	3,840	3,541	3,411	3,385	3,318
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
7) S. 2191 Constrained Nuclear & Biomass, and CCS								
ADAGE	3,975	3,796	3,902	4,026	4,012	3,806	3,436	3,011
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
8) S. 2191 Constrained Nuclear & B + Beyond Kyoto + Natural Gas Cartel								
ADAGE	3,960	3,802	3,909	4,045	4,038	3,834	3,465	3,039
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
9) Alternative Reference								
ADAGE	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
10) S. 2191 Alternative Reference								
ADAGE	4,360	3,975	3,933	3,786	3,518	3,292	3,322	3,307
IGEM	4,179	4,058	3,990	3,939	3,754	3,511	3,196	2,890

FMPA-POD1-00181

HEARING EXHIBIT - 00000344

Scenario Comparison

Electricity: Fossil Fuel Generation (Billion kWh)

(ADAGE)

Table: Electricity Generation (billion kWh) (ADAGE)

	2015	2020	2025	2030	2035	2040	2045	2050
1) EPA Reference								
Fossil	3208	3449	3676	3981	4265	4536	4787	5017
Fossil w/CCS	0	0	0	0	0	0	0	0
Nuclear	837	879	879	879	879	879	879	879
Other Non-Fossil	414	433	452	470	477	484	491	499
2) S.2191								
Fossil	2648	2526	2043	1189	92	0	0	0
Fossil w/CCS	0	166	558	1303	2405	2474	2365	2226
Nuclear	932	995	1174	1387	1603	1766	1939	2116
Other Non-Fossil	500	592	684	788	905	1040	1242	1444
3) S.2191 w/ Low International Action								
Fossil	2670	2551	2065	1216	103	1	0	0
Fossil w/CCS	0	166	558	1303	2406	2480	2384	2249
Nuclear	930	992	1171	1383	1600	1765	1936	2116
Other Non-Fossil	499	591	683	789	905	1040	1242	1444
6) S.2191 Constrained Nuclear & Biomass								
Fossil	2715	2659	2417	1827	828	431	423	410
Fossil w/CCS	0	166	555	1303	2548	3383	3566	3726
Nuclear	837	879	879	879	879	879	879	879
Other Non-Fossil	435	459	485	499	504	509	515	521
7) S.2191 Constrained Nuclear & Biomass, and CCS								
Fossil	2669	2697	2600	2430	2038	2036	1524	1513
Fossil w/CCS	0	0	0	0	166	558	1503	2785
Nuclear	837	879	879	879	879	879	879	879
Other Non-Fossil	442	485	485	499	504	510	516	522
8) S.2191 Constrained Nuclear & Biomass, and CCS + Beyond Kyoto + Natural Gas Cartel								
Fossil	2662	2706	2606	2435	2046	2043	1532	1515
Fossil w/CCS	0	0	0	0	166	558	1503	2786
Nuclear	837	879	879	879	879	879	879	879
Other Non-Fossil	442	485	485	499	504	510	516	522
9) Alternative Reference								
Fossil	3208	3449	3423	3621	3966	4136	4372	4587
Fossil w/CCS	0	0	0	0	0	0	0	0
Nuclear	914	964	964	916	916	916	916	916
Other Non-Fossil	417	441	456	480	486	493	499	507
10) S.2191 Alt. Ref.								
Fossil	2588	2419	2221	1634	716	0	0	0
Fossil w/CCS	0	166	257	699	1591	2099	2032	1890
Nuclear	924	967	1164	1375	1602	1775	1934	2103
Other Non-Fossil	439	503	568	778	918	1054	1256	1454

FMPA-POD1-00182

HEARING EXHIBIT - 00000345

Appendix 3:Comparison to EPA's Analyses of S. 280 and S. 1766

FMPA-POD1-00183
HEARING EXHIBIT - 00000346

"Lieberman-Warner Climate Security Act of 2008" (S. 2191) Bill Summary

- Economy-wide coverage:
  - Upstream on petroleum, natural gas, as well as manufacturers of F-gases and N_2O
  - Downstream on coal facilities (that use over 5,000 tons of coal per year)
- GHG emission targets for covered sectors (targets decline in each calendar year):
  - 2012: 5,775 $MtCO_2e$
  - 2020: 4,924 $MtCO_2e$
  - 2030: 3,860 $MtCO_2e$
  - 2050: 1,732 $MtCO_2e$ (70% below 2005 emissions levels from covered facilities)

- Establishes a market-driven system of tradable emission allowances
- Establishes a separate cap and trade system for HFCs

- Domestic offsets may be used to meet 15% of compliance obligation
- International credits may be used to meet 15% of compliance obligation

- Establishes a Carbon Market Efficiency Board

- Set-asides for agriculture and forestry sequestration as well as landfill and coal mine methane
- Bonus allowances for CCS similar to provisions in S. 1766
- International reserve allowance requirement similar to provisions in S. 1766

FMPA-POD1-00184

HEARING EXHIBIT - 00000347

Lieberman-McCain "Climate Stewardship and Innovation Act" (S. 280) Bill Summary

- Economy-wide coverage:
  - Transportation (upstream on fuels)
  - Electricity, Industrial, and Commercial sectors (downstream on emissions)
- Extensive GHG coverage: CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6
- GHG emission targets for covered sectors:

  2012: 2004 emission level, then adjusted for non-covered entities

  2020: 1990 emission level, then adjusted

  2050: 60% below 1990 emission level, then adjusted
- Establishes a market-driven system of tradable emission allowances
- Caps are placed on covered Entities that emit 10,000 tons CO_2e or more emissions per year
- Domestic offsets & international credits can be used to meet up to 30% of the emission cap level
  - S. 280 provides the EPA Administrator, in coordination with the Secretaries of Commerce, Energy, and Agriculture, discretion for setting standards for domestic and international mitigation activities

FMPA-POD1-00185

HEARING EXHIBIT - 00000348

Bingaman-Specter "Low Carbon Economy Act" (S. 1766) Bill Summary

- Economy-wide coverage:
  - Upstream on petroleum, natural gas, as well as manufacturers of F-gases and N_2O
  - Downstream on coal facilities (that use over 5,000 tons of coal per year)
- GHG emission targets for covered sectors (targets decline in each calendar year):

  2012: 6,652 $MtCO_2e$

  2020: 6,188 $MtCO_2e$ (approximately 2006 emissions levels)

  2050: 1,732 $MtCO_2e$ (equal to 1990 emissions levels)

  The President may set 2050 emission targets of at least 60% below 2006 levels, if the 5 largest trading partners of the U.S. are taking comparable action. According to the core international assumptions used in this analysis, both developed and developing countries take on GHG reduction targets, and thus this reduction is assumed to be enacted.

- Establishes a market-driven system of tradable emission allowances
- Technology Accelerator Payment (TAP) of \$12/tCO_2e rising at real rate of 5 percent per year
- Unlimited specified domestic offsets can be used to meet the emission cap level
  - Specified offset project categories include CH_4 from landfills, coal mines, and animal waste, and SF_6 from electric power systems
    - For other offset project categories, the President may distribute less than 1 credit for each ton of greenhouse gas emissions reduced or sequestered.
    - This analysis assumes that only offsets from specified project categories are allowed.
  - The President can implement an international offset program, allowing not more than 10% of compliance to be met through this program
- Set-asides for agriculture sequestration and bonus allowances for CCS
- Ensures comparable action from major trading partners through a specified approach of incentives (i.e., for technology deployment) and countervailing trade measures

FMPA-POD1-00186

HEARING EXHIBIT - 00000349

Policy Comparison:

Lieberman-Warner (S. 2191) – Bingaman-Specter (S. 1766) – Lieberman-McCain (S. 280)

Major Provisions

- Coverage of US GHG Emissions (based on 2005 GHG inventory)
  - S. 280: ~73%
  - S. 1766: ~83%
  - S. 2191: ~87%
- Cap rate of decline
  - S. 280: Step down decrease every 10 years
  - S. 1766: Annual decrease
  - S. 2191: Annual decrease
- Safety valve
  - S. 280: no safety valve
  - S. 1766: $12/ton of CO_2e in 2012 rising at a real rate of 5%
  - S. 2191: no safety valve
- Use of offsets
  - S. 280: 30% of compliance from domestic offsets and international credits
  - S. 1766: Unlimited specified domestic offsets can be used to meet the emission cap level
    - Specified offset project categories include CH_4 from landfills, coal mines, and animal waste, and SF_6 from electric power systems
    - The President can implement an international offset program, allowing not more than 10% of compliance to be met through this program
  - S. 2191: 15% of compliance from domestic offsets; and 15% of compliance from international credits

FMPA-POD1-00187

HEARING EXHIBIT - 00000350

Policy Comparison:

Lieberman-Warner (S. 2191) – Bingaman-Specter (S. 1766) – Lieberman-McCain (S. 280)

Scenarios from Previous Analyses

- The results presented in this appendix compare three bills analyzed by EPA:
  - S. 280
    - Lieberman-McCain, "Climate Stewardship and Innovation Act of 2007"
    - EPA analysis released July 16, 2007
    - www.epa.gov/climatechange/economics/economicanalyses.html#s280
    - Scenario 2 – S. 280 Senate Scenario
  - S. 1766
    - Bingaman-Specter, "Low Carbon Economy Act of 2007"
    - EPA analysis released January 15, 2008
    - www.epa.gov/climatechange/economics/economicanalyses.html#s1766
    - Scenario 2 – S. 1766
  - S. 2191
    - "Lieberman-Warner Climate Security Act of 2008"
    - EPA analysis contained in this document
    - www.epa.gov/climatechange/economics/economicanalyses.html#s2191
    - Scenario 2 – S. 2191
- The same reference case was used in each of the analyses described above

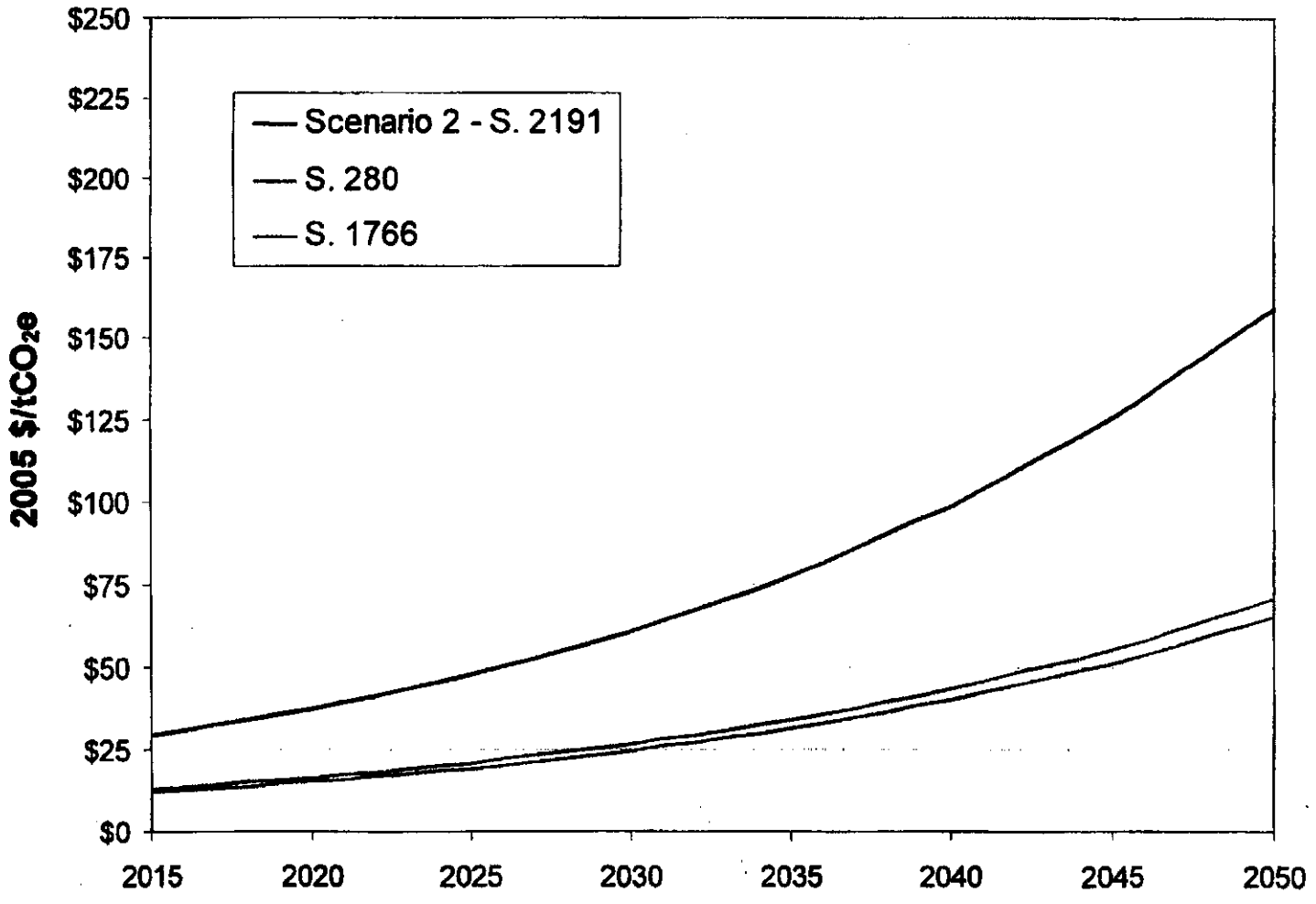
FMPA-POD1-00188

HEARING EXHIBIT - 00000351

Policy Comparison:

Lieberman-Warner (S. 2191) – Bingaman-Specter (S. 1766) – Lieberman-McCain (S. 280)

GHG Allowance Prices (IGEM)



EPA Analysis of S. 2191

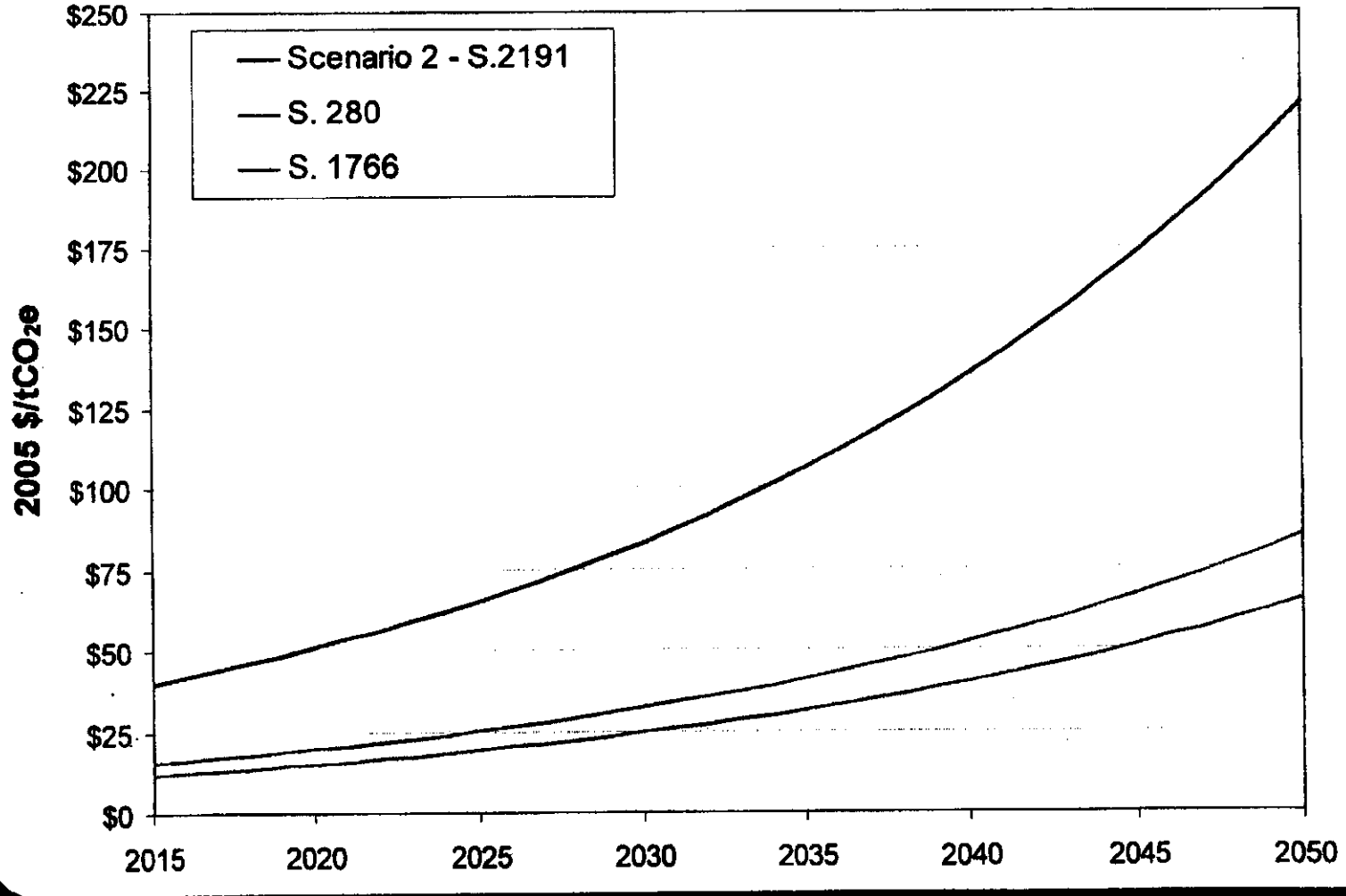
FMPA-POD1-00189

HEARING EXHIBIT - 00000352

Policy Comparison:

Lieberman-Warner (S. 2191) – Bingaman-Specter (S. 1766) – Lieberman-McCain (S. 280)

GHG Allowance Prices (ADAGE)



EPA Analysis of S. 2191

FMPA-POD1-00190

HEARING EXHIBIT - 00000353

Policy Comparison:

Lieberman-Warner (S. 2191) – Bingaman-Specter (S. 1766) – Lieberman-McCain (S. 280)

GHG Allowance Prices (2005$/tCO$_2$e)

Table: Allowance Price Comparisons (2005 $/tCO2e)

	2015	2020	2025	2030	2035	2040	2045	2050
Reference								
ADAGE	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
IGEM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Scenario 2 - S. 2191								
ADAGE	$29	$37	$48	$61	$77	$98	$125	$159
IGEM	$40	$51	$65	$83	$106	$135	$173	$220
S. 1766								
ADAGE	$12	$15	$19	$25	$31	$40	$51	$65
IGEM	$12	$15	$19	$25	$31	$40	$51	$65
S. 280								
ADAGE	$13	$16	$21	$27	$34	$43	$55	$70
IGEM	$15	$20	$25	$32	$41	$52	$67	$85

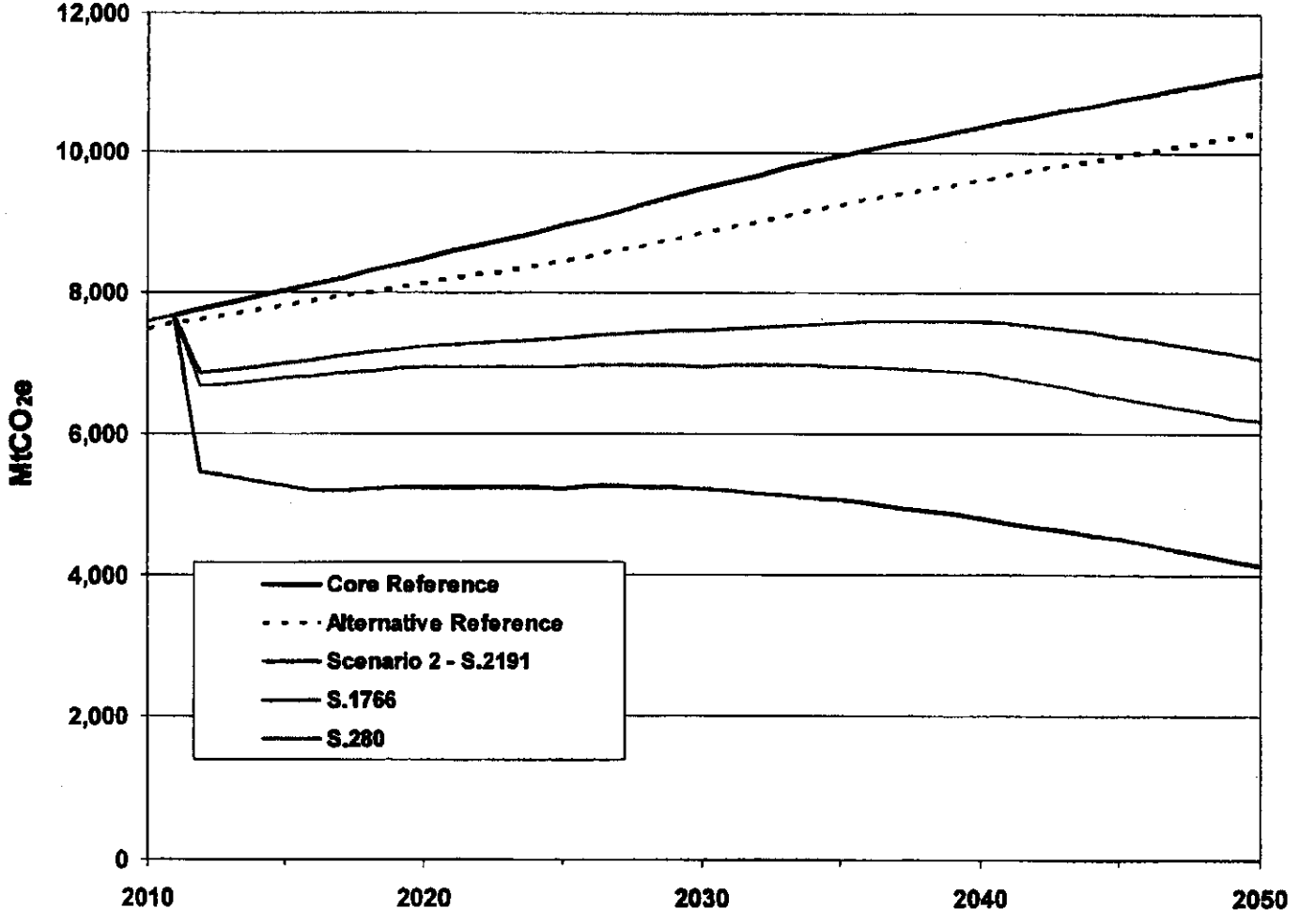
FMPA-POD1-00191

HEARING EXHIBIT - 00000354

Policy Comparison:

Lieberman-Warner (S. 2191) – Bingaman-Specter (S. 1766) – Lieberman-McCain (S. 280)

Total U.S. GHG Emissions ($MtCO_2e$) (IGEM)



EPA Analysis of S. 2191

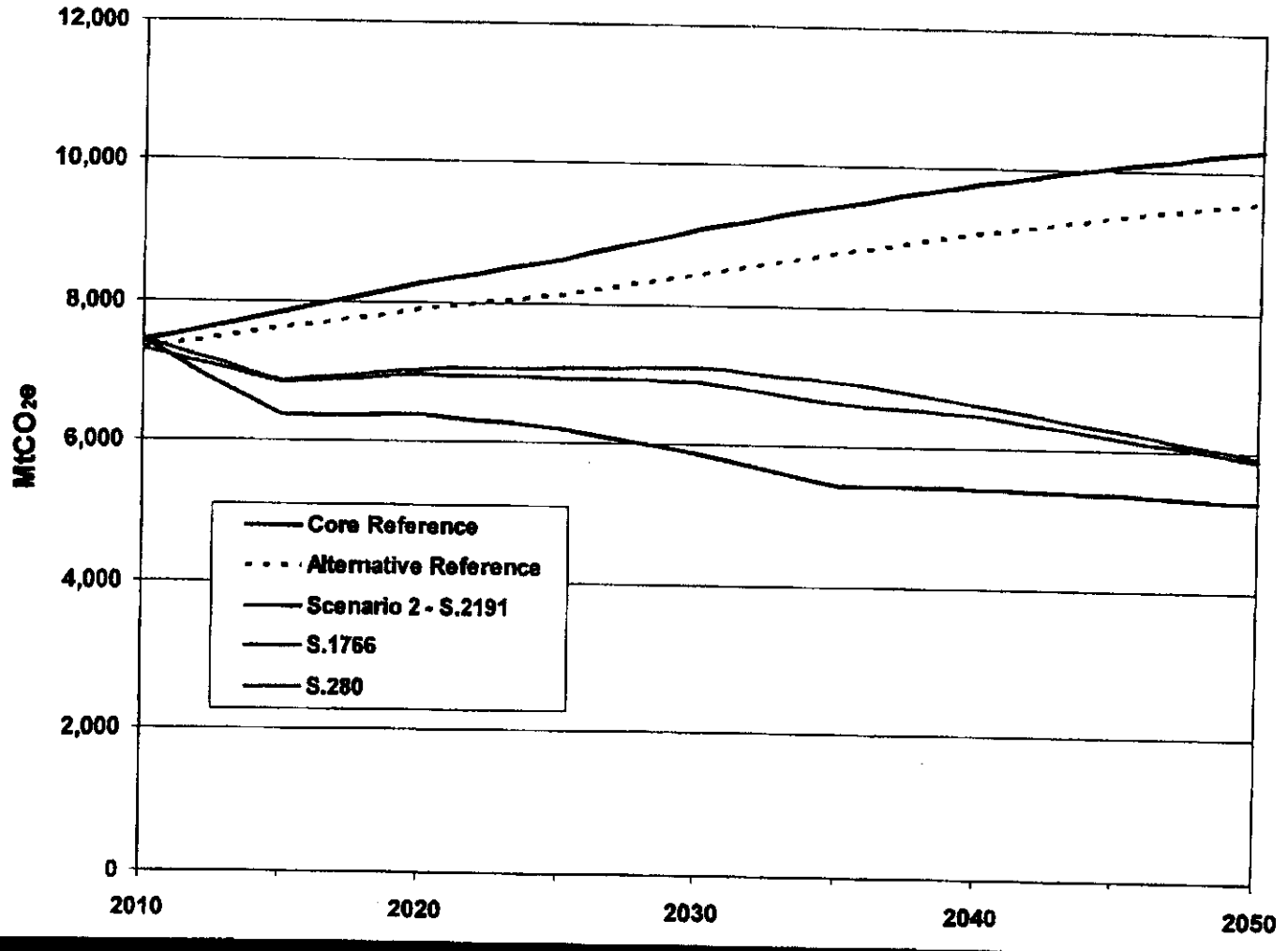
FMPA-POD1-00192

HEARING EXHIBIT - 00000355

Policy Comparison:

Lieberman-Warner (S. 2191) – Bingaman-Specter (S. 1766) – Lieberman-McCain (S. 280)

Total U.S. GHG Emissions ($MtCO_2e$) (ADAGE)



EPA Analysis of S. 2191

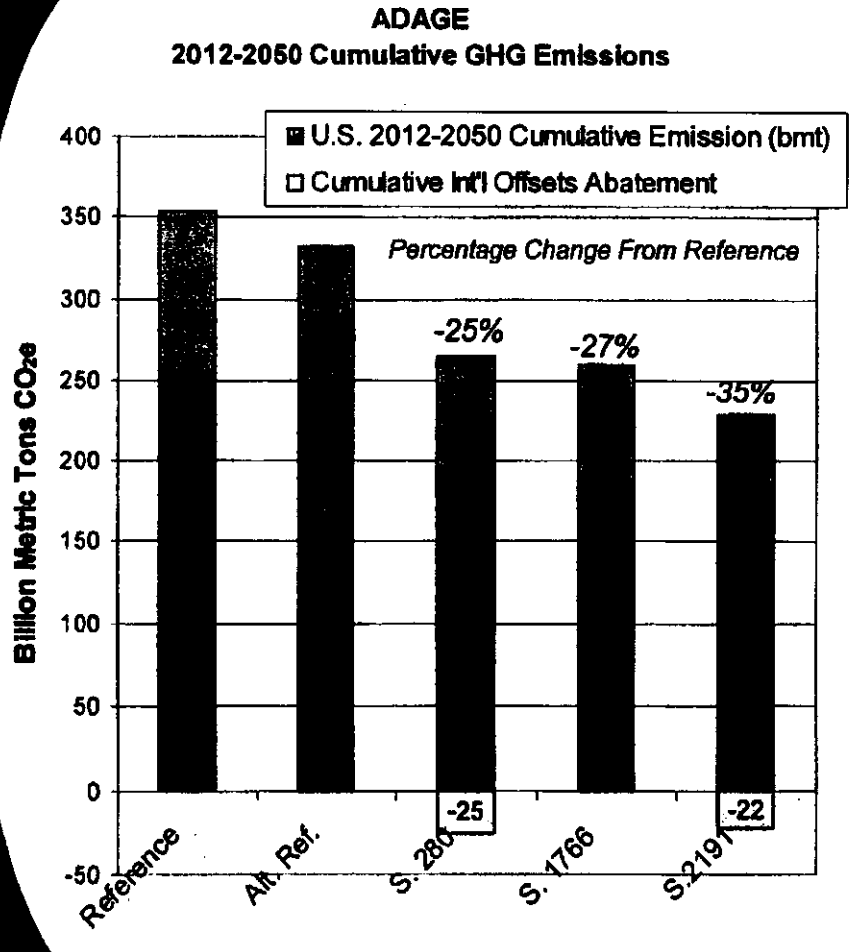
FMPA-POD1-00193

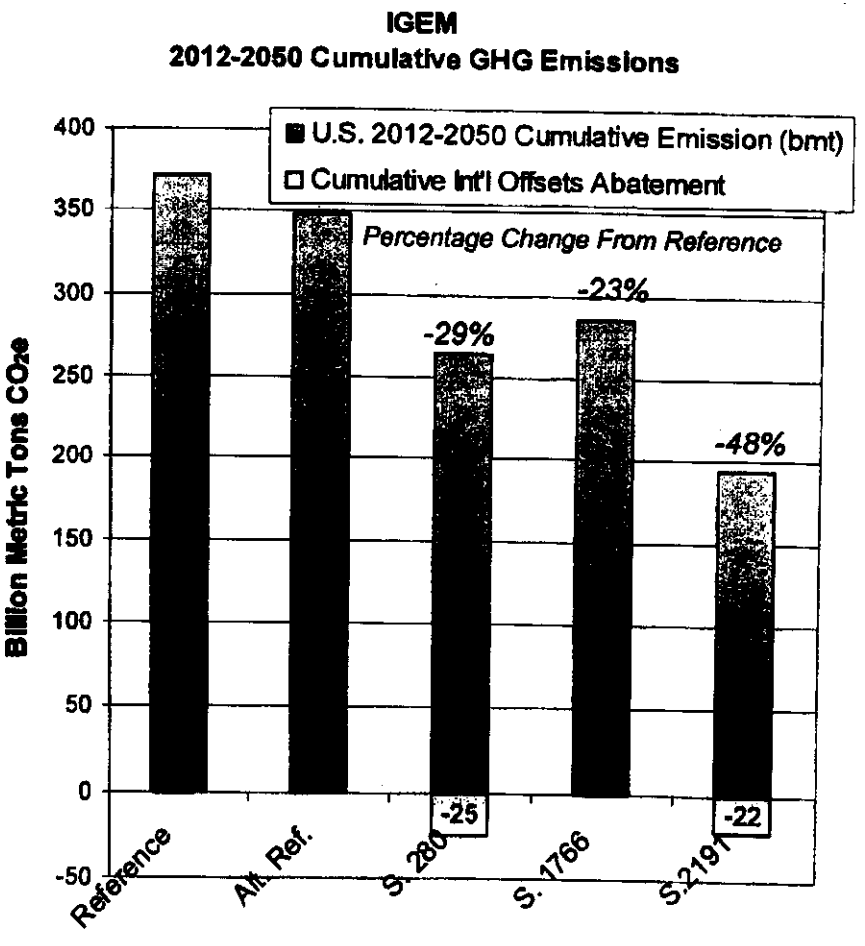
HEARING EXHIBIT - 00000356

Policy Comparison:

Lieberman-Warner (S. 2191) – Bingaman-Specter (S. 1766) – Lieberman-McCain (S. 280)

2012 – 2050 Cumulative U.S. GHG Emissions (Billion Metric Tons CO_2e)





EPA Analysis of S. 2191

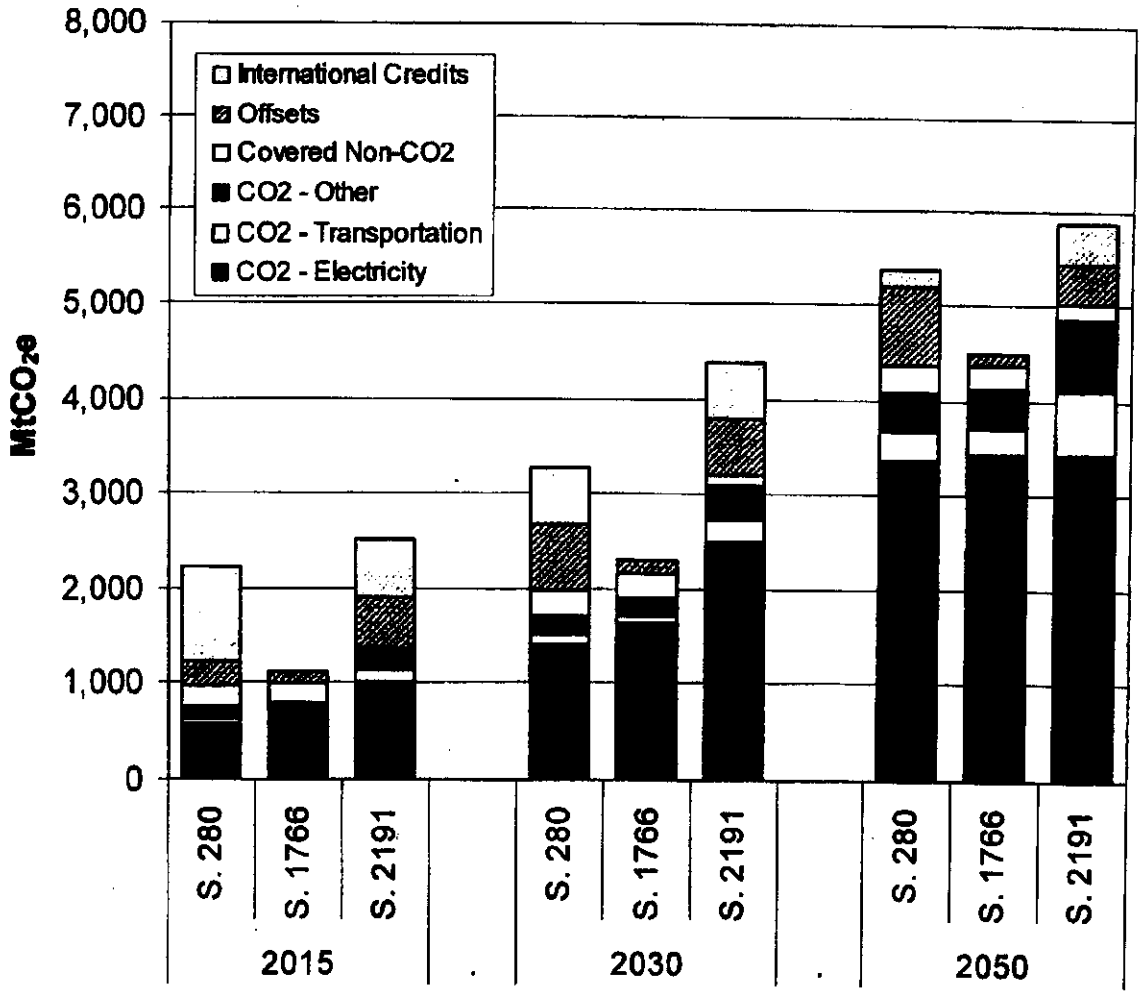
FMPA-POD1-00194

HEARING EXHIBIT - 00000357

Policy Comparison:

Lieberman-Warner (S. 2191) – Bingaman-Specter (S. 1766) – Lieberman-McCain (S. 280)

Sources of GHG Abatement (ADAGE)

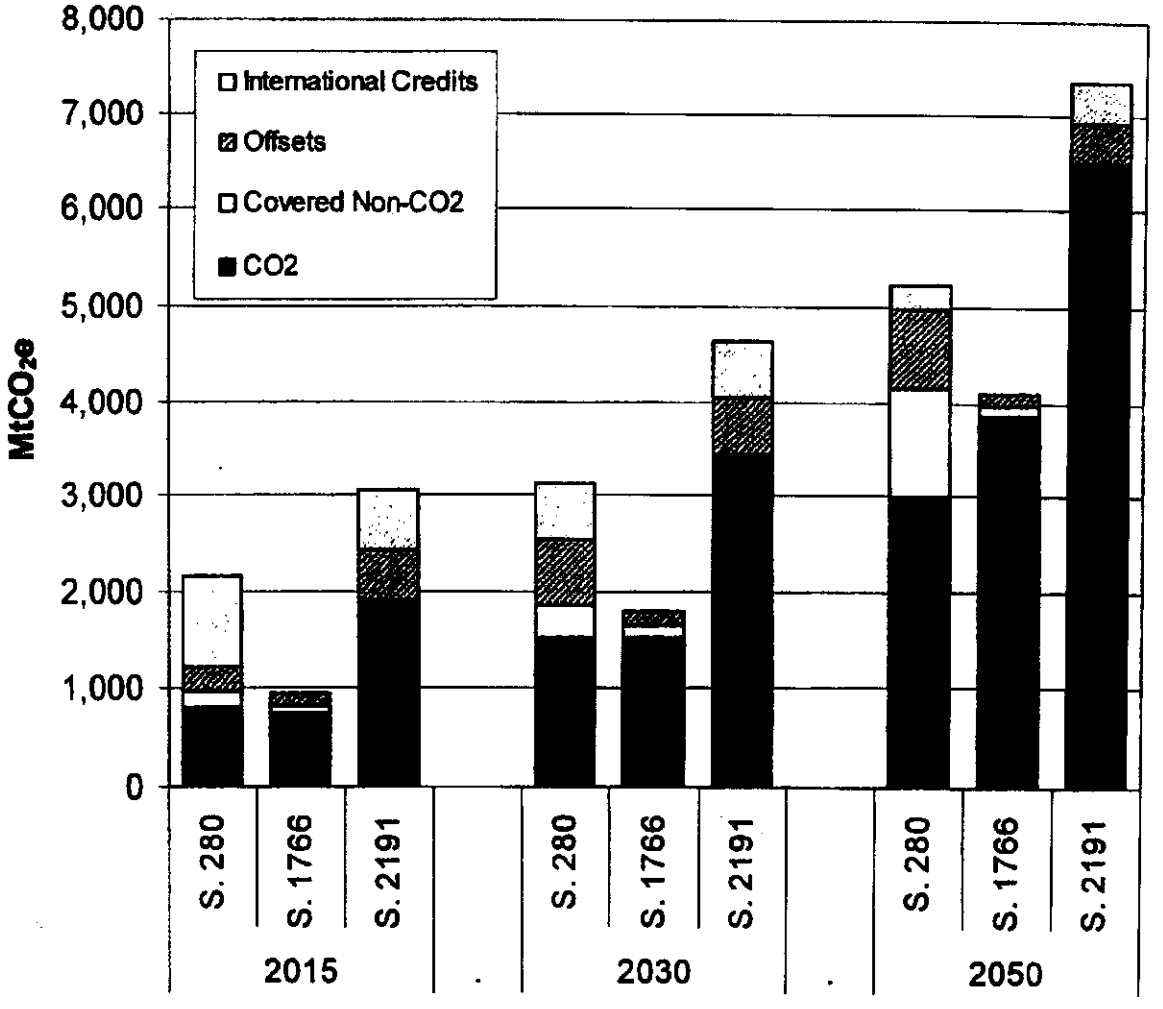


FMPA-POD1-00195
HEARING EXHIBIT - 00000358

Policy Comparison:

Lieberman-Warner (S. 2191) – Bingaman-Specter (S. 1766) – Lieberman-McCain (S. 280)

Sources of GHG Abatement (IGEM)



EPA Analysis of S. 2191

FMPA-POD1-00196

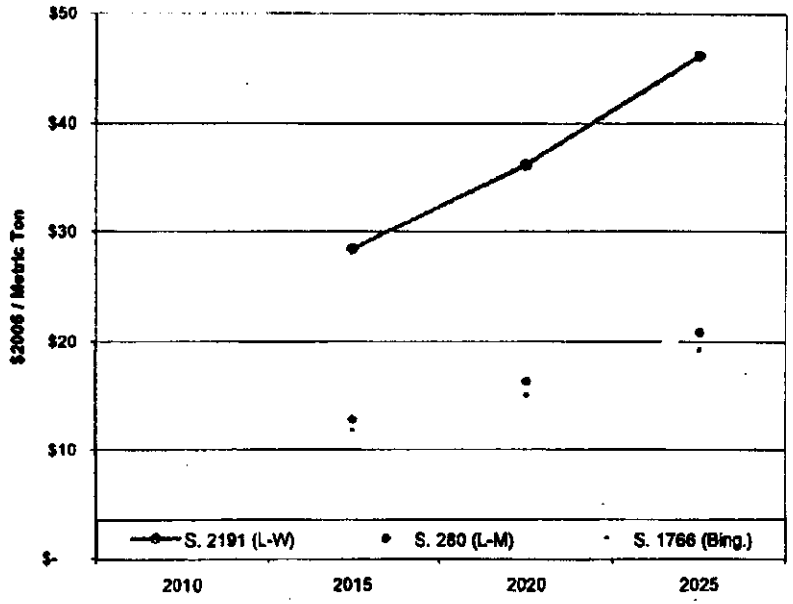
HEARING EXHIBIT - 00000359

Policy Comparison:

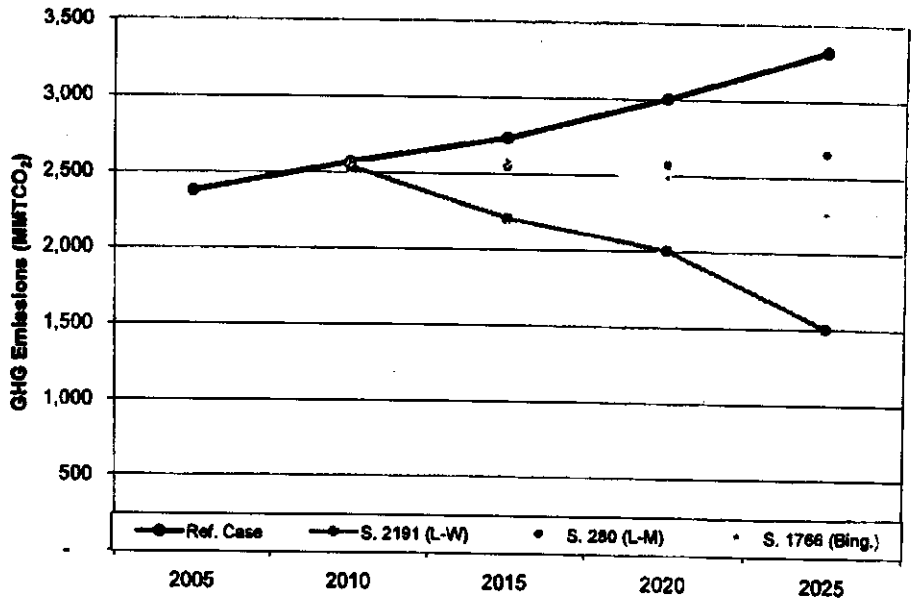
Lieberman-Warner (S. 2191) – Bingaman-Specter (S. 1766) – Lieberman-McCain (S. 280)

CO_2 Allowance Prices and Power Sector CO_2 Emissions (IPM)

CO_2 Allowance Price (inputs to IPM)



Power Sector CO_2 Emissions



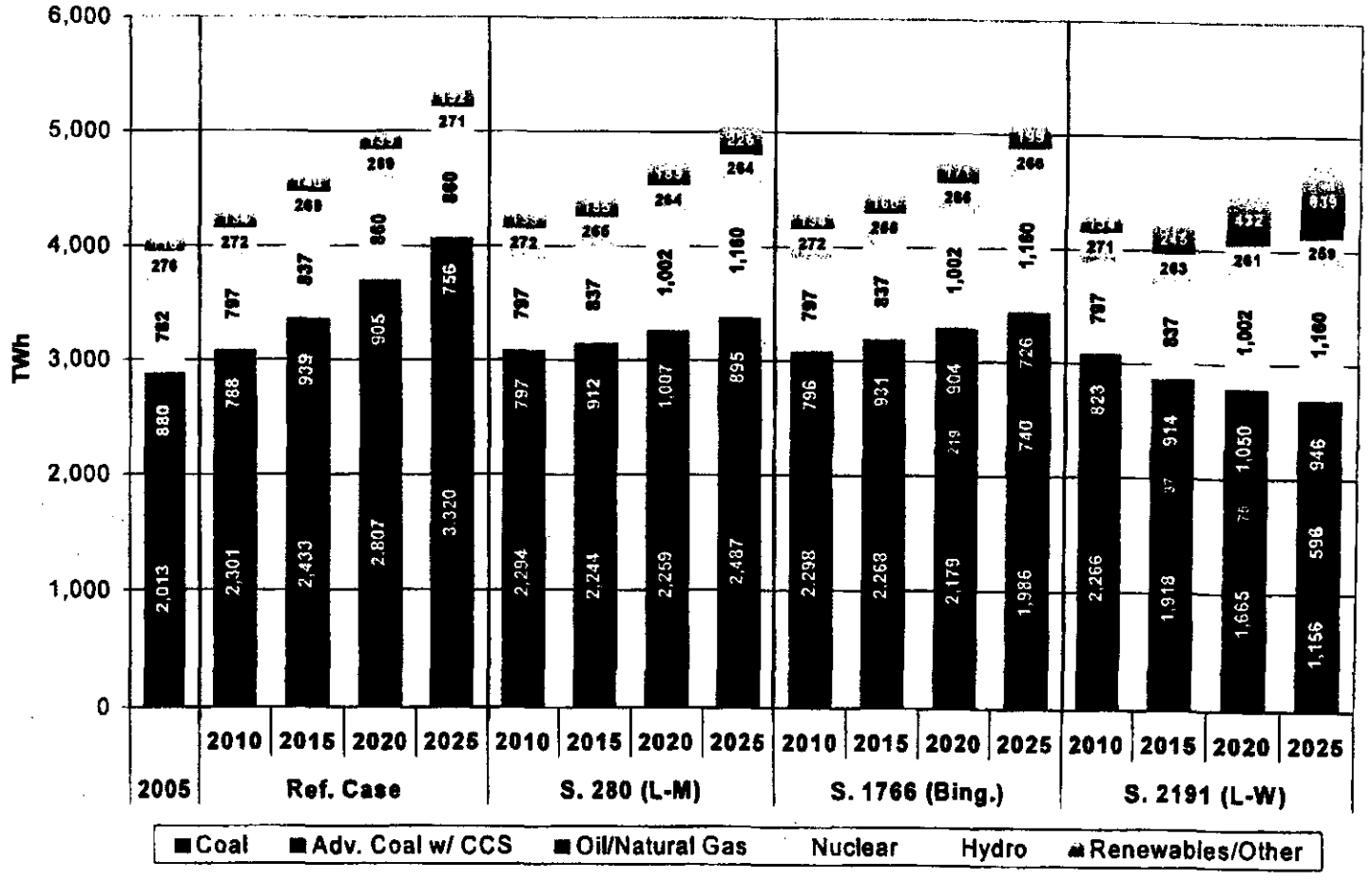
FMPA-POD1-00197

HEARING EXHIBIT - 00000360

Policy Comparison:

Lieberman-Warner (S. 2191) – Bingaman-Specter (S. 1766) – Lieberman-McCain (S. 280)

Electricity Generation Mix (IPM)



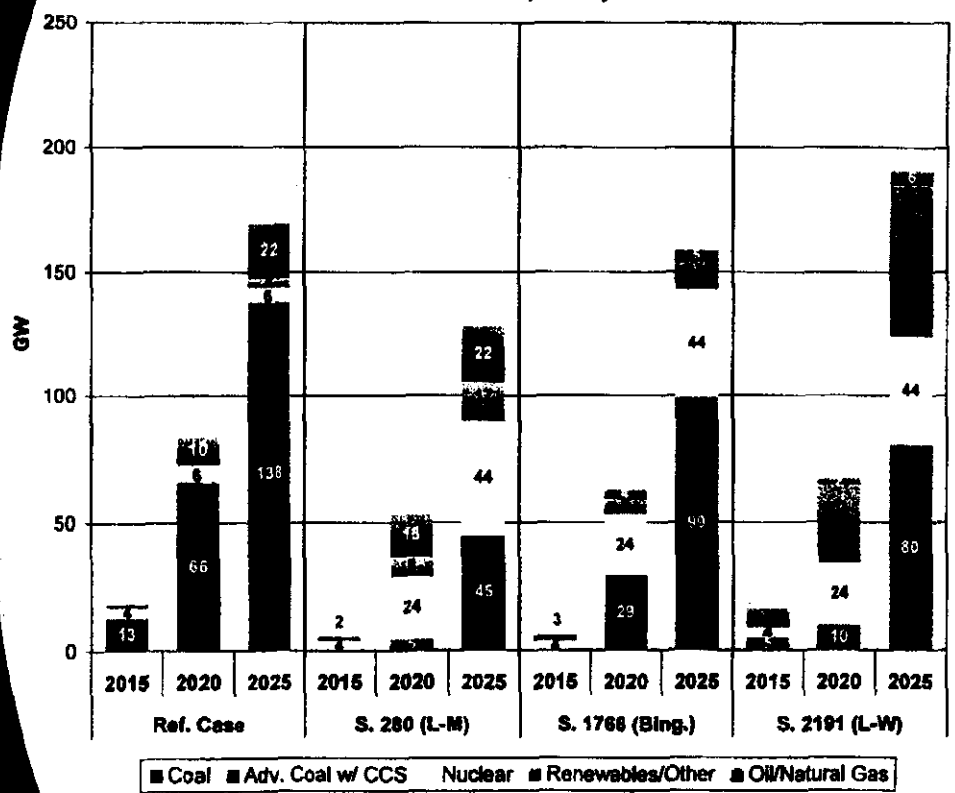
FMPA-POD1-00198

HEARING EXHIBIT - 00000361

Policy Comparison:

Lieberman-Warner (S. 2191) – Bingaman-Specter (S. 1766) – Lieberman-McCain (S. 280)

New Generation Capacity (IPM)



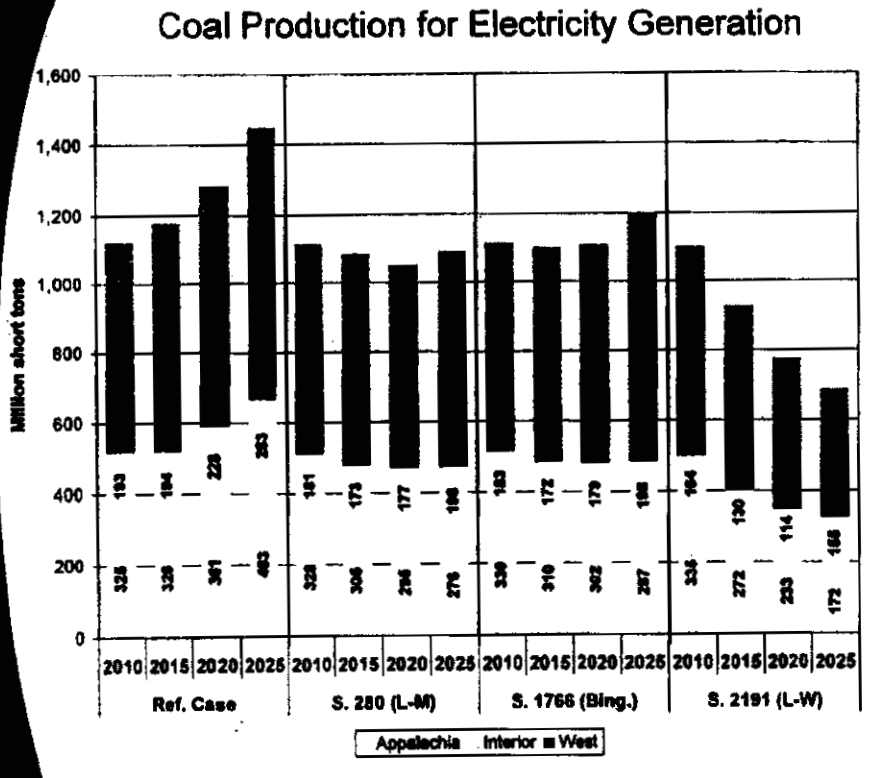
Note: New capacity additions less that 1 GW of capacity are not indicated.

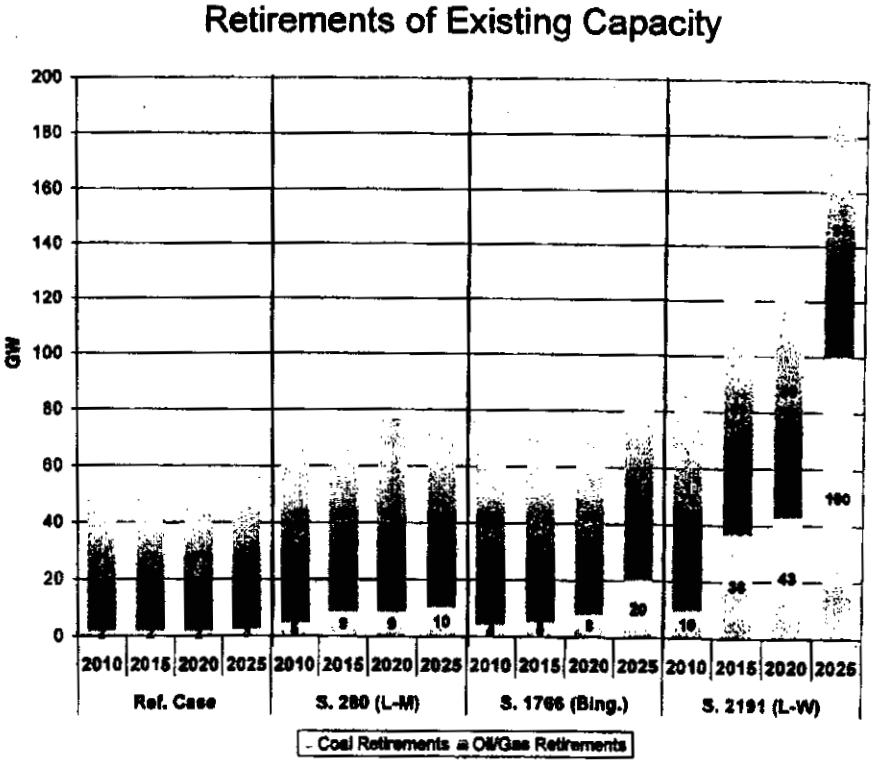
- S. 2191 contains an allowance bonus provision, which is capped, for CO_2 emissions that are captured and sequestered, resulting in significant penetration of new coal capacity with CCS technology (S. 1766 has a similar provision).
  - Bonus allowances go unused in 2015 only, when there is a 5 GW constraint on new adv. coal with CCS (the bonus is used entirely in all years post-2015).
- In 2025, adv. coal with CCS is economic even without the bonus.
- S. 2191 also results in significant penetration of new nuclear and renewable capacity.
- More capacity is built under S. 2191 because a significant amount of the existing fossil fleet is not economic to operate and must be replaced.

New Capacity Limitations in IPM (Incremental/Cumulative)				
GW	2010	2015	2020	2025
Nuclear	N/A	4	20 / 24	20 / 44
Adv. Coal w/ CCS	N/A	5	70 / 75	70 / 145
Renewables *(Cumulative Only)*	4	24	44	64

FMPA-POD1-00199
HEARING EXHIBIT - 00000362

Coal Production for Electricity Generation & Retirements of Existing Capacity (IPM)





- There is are also considerable re-powering of coal to natural gas in the S. 2191 case.

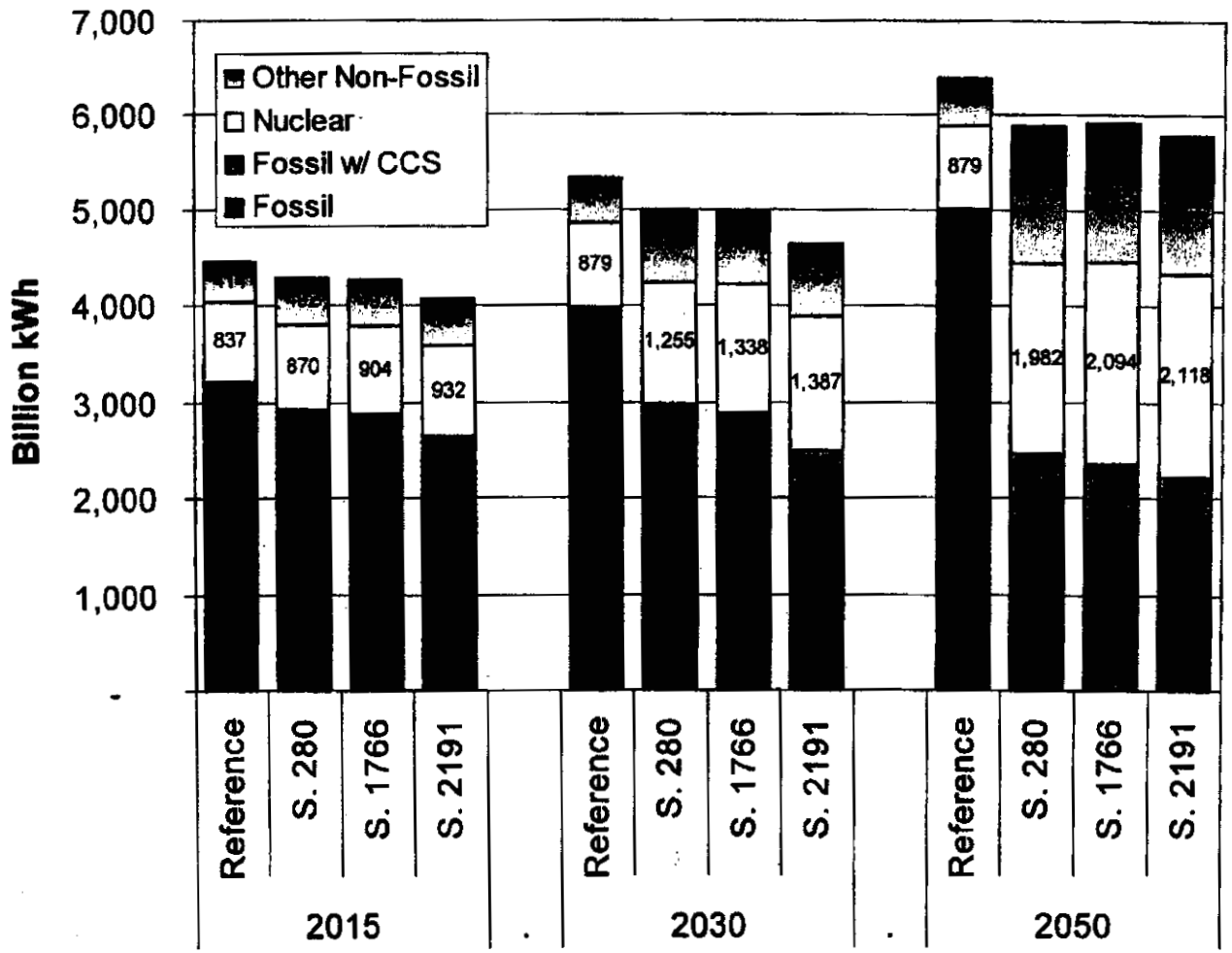
Note: Regional coal production data includes coal production for power generation only.

FMPA-POD1-00200
HEARING EXHIBIT - 00000363

Policy Comparison:

Lieberman-Warner (S. 2191) – Bingaman-Specter (S. 1766) – Lieberman-McCain (S. 280)

Electricity Generation (Billion kWh) (ADAGE)



FMPA-POD1-00201

HEARING EXHIBIT - 00000364

S. 280 Other Non-Fossil Generation Sensitivity

(ADAGE)

- The representation of renewable energy in ADAGE changed between the S. 280 analysis and the S. 1766 and S. 2191 analyses.
- For the S. 280 analysis, much of the non-fossil electricity generation in ADAGE was exogenously fixed, so the analysis showed very little increase in renewable energy compared to the reference case.
- For this analyses of S. 1766 and S. 2191, ADAGE augmented its representation of other non-fossil generation with the response curves for biomass electricity generation from the FASOM model.
- The following results show the impact of including this updated representation of biomass electricity generation on the ADAGE 'S. 280 Senate Scenario' from EPA's analysis of S. 280.
    - Other non-fossil electricity generation grows by ~250% from 2010 to 2050. In comparison, the original S. 280 analysis showed growth of ~30% over the same time period.
    - With increased renewable electricity generation, less fossil with CCS generation is required.
    - Allowance prices start at ~ $1.8 lower in 2015 than in EPA's original S. 280 analysis. The allowance price is $23.0 in 2030, and $60.8 /t$CO_2$e in 2050. In comparison, the original S. 280 analysis yielded allowance prices of $26.6 in 2030, and $70.3 /t$CO_2$e in 2050.
    - GDP impacts are slightly smaller (-0.51% in 2030, and -1.06% in 2050). Under the original S. 280 analysis, GDP impacts were -0.55% in 2030, and -1.07% in 2050.

FMPA-POD1-00202

HEARING EXHIBIT - 0000365

Policy Comparison:

Lieberman-Warner (S. 2191) – Bingaman-Specter (S. 1766) – Lieberman-McCain (S. 280)

GDP

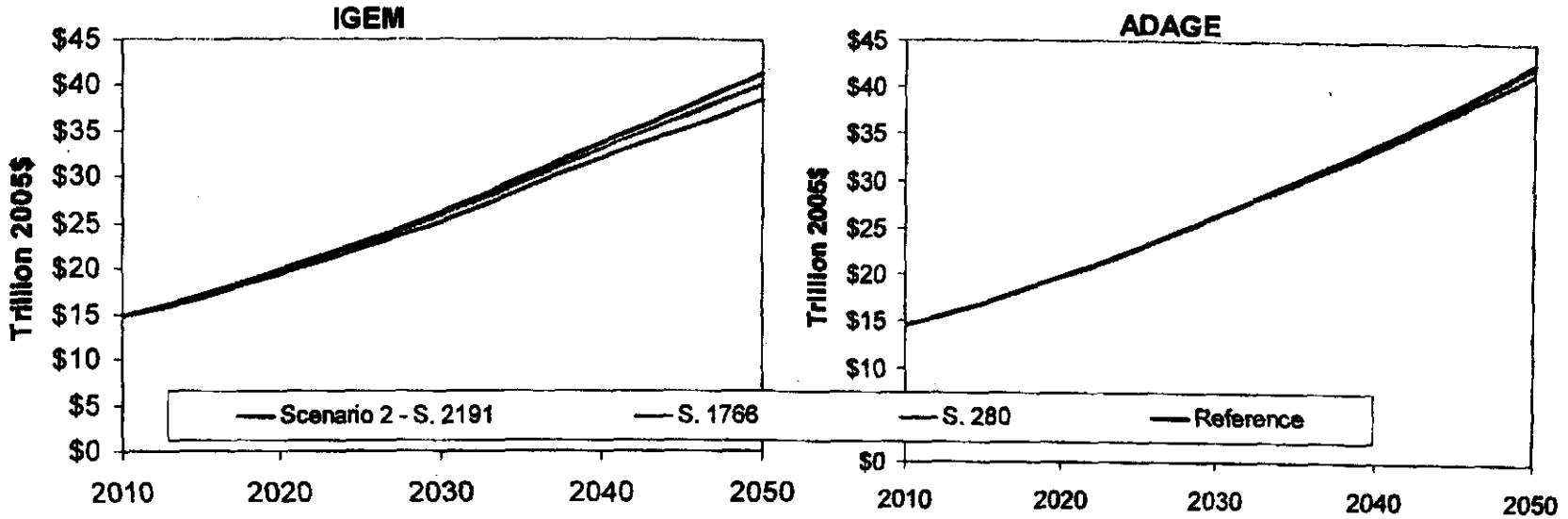


Table: **Impact of S. 280, S.1766, and S. 2191 on U.S. GDP (Billion 2005 Dollars)**

IGEM

	2010	2020	2030	2040	2050
Scenario 2 - S. 2191					
Absolute Change	-$138	-$506	-$983	-$1,752	-$2,856
% Change	-0.94%	-2.55%	-3.76%	-5.20%	-6.90%
S. 1766					
Absolute Change	-$51	-$182	-$369	-$690	-$1,196
% Change	-0.34%	-0.92%	-1.41%	-2.05%	-2.89%
S. 280					
Absolute Change	-$55	-$206	-$419	-$775	-$1,328
% Change	-0.37%	-1.04%	-1.60%	-2.30%	-3.21%

ADAGE

	2010	2020	2030	2040	2050
Scenario 2 - S. 2191					
Absolute Change	-$27	-$137	-$238	-$488	-$1,012
% Change	-0.18%	-0.69%	-0.90%	-1.44%	-2.37%
S. 1766					
Absolute Change	-$17	-$78	-$124	-$200	-$401
% Change	-0.12%	-0.39%	-0.47%	-0.59%	-0.94%
S. 280					
Absolute Change	-$15	-$71	-$133	-$208	-$430
% Change	-0.10%	-0.36%	-0.50%	-0.61%	-1.01%

FMPA-POD1-00203
HEARING EXHIBIT - 00000366

Policy Comparison:

Lieberman-Warner (S. 2191) – Bingaman-Specter (S. 1766) – Lieberman-McCain (S. 280)

Consumption

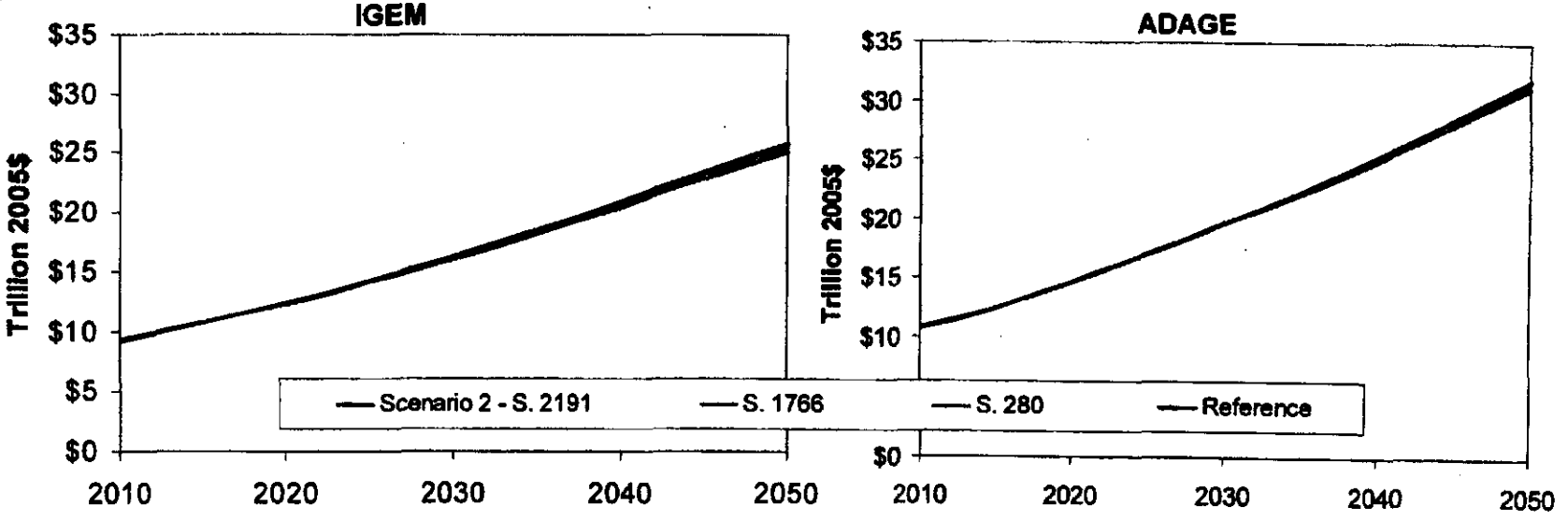


Table: **Impact of S. 280, S.1766, and S. 2191 on U.S. Consumption (2005 Dollars)**

IGEM	2010	2020	2030	2040	2050
Scenario 2 - S. 2191					
Change Per HH	$300	-$608	-$1,574	-$2,943	-$4,771
% Change	0.39%	-0.66%	-1.44%	-2.28%	-3.26%
S. 1766					
Change Per HH	$110	-$176	-$511	-$969	-$1,656
% Change	0.14%	-0.19%	-0.47%	-0.77%	-1.13%
S. 280					
Change Per HH	$115	-$230	-$625	-$1,211	-$1,990
% Change	0.15%	-0.25%	-0.57%	-0.94%	-1.36%

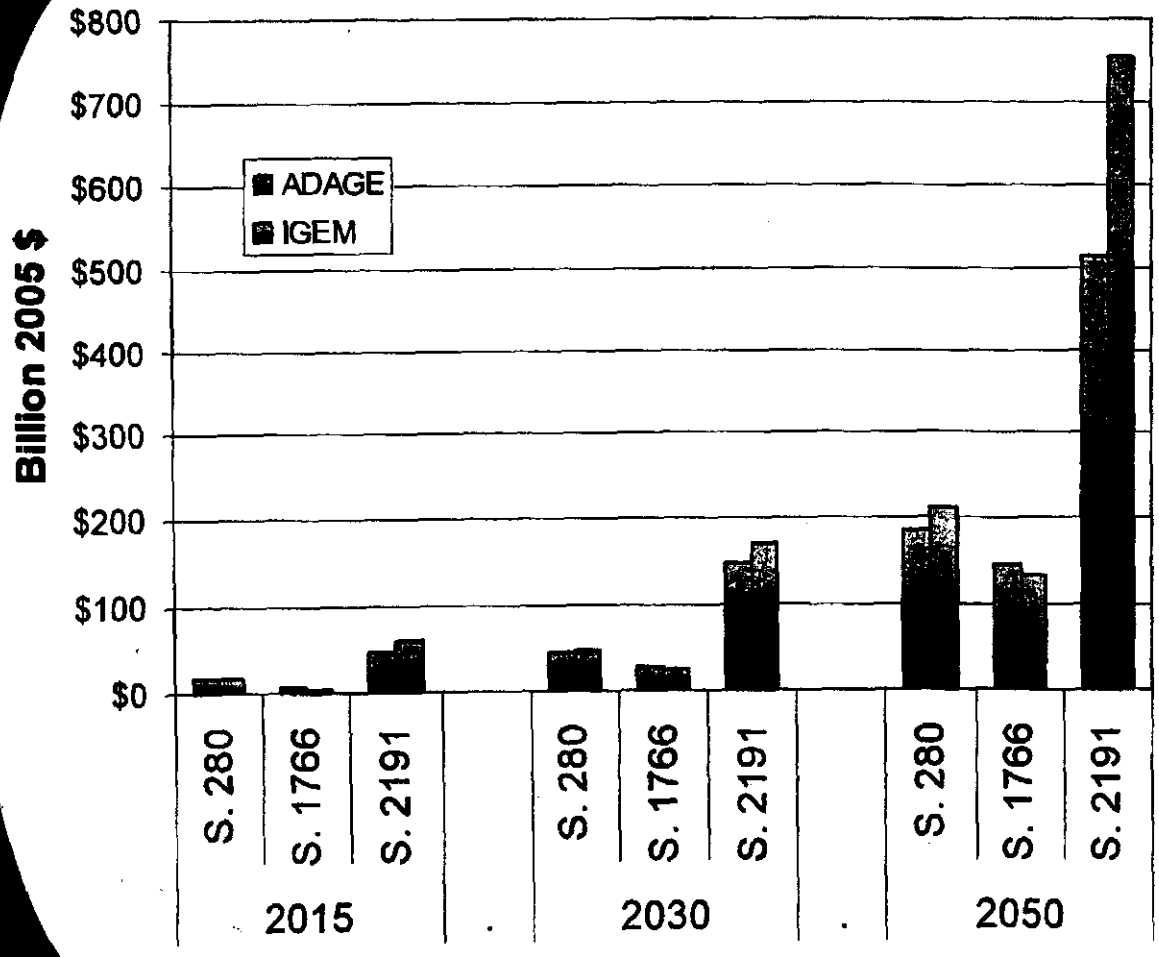
ADAGE	2010	2020	2030	2040	2050
Scenario 2 - S. 2191					
Change Per HH	$574	-$446	-$1,176	-$2,188	-$3,984
% Change	0.69%	-0.43%	-0.91%	-1.39%	-2.10%
S. 1766					
Change Per HH	$214	-$333	-$459	-$785	-$1,590
% Change	0.26%	-0.32%	-0.36%	-0.50%	-0.84%
S. 280					
Change Per HH	$391	-$53	-$483	-$1,093	-$1,876
% Change	0.47%	-0.05%	-0.38%	-0.70%	-0.99%

FMPA-POD1-00204
HEARING EXHIBIT - 00000367

Policy Comparison:

Lieberman-Warner (S. 2191) – Bingaman-Specter (S. 1766) – Lieberman-McCain (S. 280)

Total Abatement Cost



- Total abatement cost is simply the sum of domestic covered abatement cost, domestic offset abatement cost, and payments for international credits.
- Domestic covered abatement cost is approximated for each model as the product of domestic covered GHG emissions abatement and the allowance price divided by two.
  - Division by 2 is assumed to represent the fact that most reduction measures are not implemented at the marginal allowance price but at lower prices. In most cases, the relationship between emission reduction and the marginal price is a concave curve – which implies a value larger than 2. The value of 2, used here for simplicity leads to an overestimation of abatement costs.
- Domestic offset abatement cost is approximated for each model as the product of domestic offset abatement and the offset price divided by two.
- International credit payments are calculated for each model as the product of the amount of international credits purchased and the international credit price.
  - Unlike the abatement costs associated with domestic covered abatement and domestic offsets, there is no need for dividing by two when calculating the costs of international credits as all international credits are purchased at the full price of international allowances and those payments are sent abroad.

FMPA-POD1-00205

HEARING EXHIBIT - 00000368

Appendix 4: Additional Information

FMPA-POD1-00206

HEARING EXHIBIT - 00000369

Results: Scenario 2 - S. 2191

Fuel Price Adders for 2050 (ADAGE)

	2005 Price	2050 Producer Price	2050 Cost of Carbon Content	2050 End - User Price
Metric Ton of CO_2	n/a		$159.13	
Metric Ton of Carbon	n/a		$583.48	
Barrel of Oil	$50.28	$53.52	$68.11	$121.64
Gallon of Gasoline	$2.34	$2.49	$1.40	$3.89
Short Ton of Coal	$36.79	$39.40	$351.76	$391.16
Short Ton of Coal w/ CCS	$36.79	$39.40	$35.18	$74.58
tCf of Natural Gas	$7.51	$6.37	$8.65	$15.02

- The 2030 producer price is obtained by multiplying the 2030 index price in ADAGE by the 2005 price from EIA's 2006 Monthly Energy Review.
- The cost of carbon content is simply the product of the physical carbon content of the fuel and the allowance price.
- The end-user price is simply the sum of the producer price and the cost of carbon content.
- CCS technology for coal fired power generation captures and stores 90% of carbon emissions, which lowers the cost of carbon content by 90%, and lowers the consumer price accordingly.
- The cost of the carbon content increases the price of gasoline by 21%, increases the price of oil by 47%, increases the price of natural gas by 57%, increases the price of coal by 360%, and increases the price of coal used with CCS by 36%.
- Bonus allowances for CCS are not considered here.

FMPA-POD1-00207
HEARING EXHIBIT - 00000370

Results: Scenario 7 - S. 2191 Constrained Nuclear, Biomass, and CCS

Fuel Price Adders for 2030 (ADAGE)

		2030		
	2005 Price	Producer Price	Cost of Carbon Content	End - User Price
Metric Ton of CO_2	n/a		$112.15	
Metric Ton of Carbon	n/a		$411.21	
Barrel of Oil	$50.28	$55.35	$48.00	$103.36
Gallon of Gasoline	$2.34	$2.58	$0.99	$3.56
Short Ton of Coal	$36.79	$37.24	$247.90	$285.14
Short Ton of Coal w/ CCS	$36.79	$37.24	$24.79	$62.03
tCf of Natural Gas	$7.51	$5.79	$6.10	$11.89

- The 2030 producer price is obtained by multiplying the 2030 index price in ADAGE by the 2005 price from EIA's 2006 Monthly Energy Review.
- The cost of carbon content is simply the product of the physical carbon content of the fuel and the allowance price.
- The end-user price is simply the sum of the producer price and the cost of carbon content.
- CCS technology for coal fired power generation captures and stores 90% of carbon emissions, which lowers the cost of carbon content by 90%, and lowers the consumer price accordingly.
- The cost of the carbon content increases the price of gasoline by 21%, increases the price of oil by 47%, increases the price of natural gas by 57%, increases the price of coal by 360%, and increases the price of coal used with CCS by 36%.
- Bonus allowances for CCS are not considered here.

FMPA-POD1-00208
HEARING EXHIBIT - 00000371

Results: Scenario 7 - S. 2191 Constrained Nuclear, Biomass, and CCS

Fuel Price Adders for 2050 (ADAGE)

		2050		
	2005 Price	Producer Price	Cost of Carbon Content	End - User Price
Metric Ton of CO_2	n/a		$290.14	
Metric Ton of Carbon	n/a		$1,063.83	
Barrel of Oil	$50.28	$53.52	$124.19	$177.71
Gallon of Gasoline	$2.34	$2.49	$2.56	$5.05
Short Ton of Coal	$36.79	$39.40	$641.35	$680.75
Short Ton of Coal w/ CCS	$36.79	$39.40	$64.13	$103.54
tCf of Natural Gas	$7.51	$6.37	$15.78	$22.15

- The 2030 producer price is obtained by multiplying the 2030 index price in ADAGE by the 2005 price from EIA's 2006 Monthly Energy Review.
- The cost of carbon content is simply the product of the physical carbon content of the fuel and the allowance price.
- The end-user price is simply the sum of the producer price and the cost of carbon content.
- CCS technology for coal fired power generation captures and stores 90% of carbon emissions, which lowers the cost of carbon content by 90%, and lowers the consumer price accordingly.
- The cost of the carbon content increases the price of gasoline by 21%, increases the price of oil by 47%, increases the price of natural gas by 57%, increases the price of coal by 360%, and increases the price of coal used with CCS by 36%.
- Bonus allowances for CCS are not considered here.

FMPA-POD1-00209

HEARING EXHIBIT - 00000372

Results: Scenario 2 – S. 2191

2030 Sectoral Results (Sectors 1 – 18) (IGEM)

Sector	2007	2030				
		Reference		S.2191 Scenario 2		
	Output ($Billions)	Output ($Billions)	Percent Change from 2007	Output ($Billions)	Percent Change from 2007	Percent Change from Reference
Agriculture, forestry, fisheries	511	1029	101%	1115	118%	8%
Metal mining	83	165	98%	149	80%	-9%
Coal mining	30	42	39%	18	-41%	-58%
Crude oil and gas extraction	165	241	46%	207	26%	-14%
Non-metallic mineral mining	17	15	-11%	13	-20%	-10%
Construction	1195	1639	37%	1561	31%	-5%
Food and kindred products	587	1199	104%	1304	122%	9%
Tobacco manufactures	34	60	79%	68	104%	14%
Textile mill products	86	239	178%	217	153%	-9%
Apparel and other textile products	81	226	180%	218	170%	-4%
Lumber and wood products	153	344	124%	316	106%	-8%
Furniture and fixtures	104	234	125%	219	111%	-6%
Paper and allied products	225	577	156%	541	140%	-6%
Printing and publishing	253	457	81%	445	76%	-3%
Chemicals and allied products	535	1453	172%	1274	138%	-12%
Petroleum refining	307	403	31%	297	-4%	-27%
Rubber and plastic products	226	571	152%	526	132%	-8%
Leather and leather products	13	35	167%	34	155%	-4%

FMPA-POD1-00210

HEARING EXHIBIT - 00000373

Results: Scenario 2 – S. 2191

2030 Sectoral Results (Sectors 19 – 35) (IGEM)

Sector	2007	2030				
		Reference		S.2191 Scenario 2		
	Output ($Billions)	Output ($Billions)	Percent Change from 2007	Output ($Billions)	Percent Change from 2007	Percent Change from Reference
Stone, clay and glass products	121	259	114%	247	104%	-5%
Primary metals	213	465	119%	409	92%	-12%
Fabricated metal products	329	649	97%	598	82%	-8%
Non-electrical machinery	655	2478	278%	2296	250%	-7%
Electrical machinery	465	3401	631%	3161	580%	-7%
Motor vehicles	532	1137	114%	1060	99%	-7%
Other transportation equipment	227	436	92%	418	84%	-4%
Instruments	261	587	125%	562	115%	-4%
Miscellaneous manufacturing	69	182	166%	174	154%	-4%
Transportation and warehousing	707	1334	89%	1260	78%	-5%
Communications	537	1181	120%	1175	119%	0%
Electric utilities (services)	399	569	43%	460	15%	-19%
Gas utilities (services)	52	63	20%	43	-17%	-31%
Wholesale and retail trade	2590	4883	89%	4657	80%	-5%
Finance, insurance and real estate	2743	6307	130%	6230	127%	-1%
Personal and business services	4468	8419	88%	8367	87%	-1%
Government enterprises	467	874	87%	847	81%	-3%

FMPA-POD1-00211

HEARING EXHIBIT - 00000374

Results: Scenario 2 – S. 2191

2050 Sectoral Results (Sectors 1 – 18) (IGEM)

Sector	2007	2050				
		Reference		S.2191 Scenario 2		
	Output ($Billions)	Output ($Billions)	Percent Change from 2007	Output ($Billions)	Percent Change from 2007	Percent Change from Reference
Agriculture, forestry, fisheries	511	1515	197%	1688	231%	11%
Metal mining	83	256	208%	217	161%	-15%
Coal mining	30	53	77%	13	-56%	-75%
Crude oil and gas extraction	165	325	97%	235	43%	-28%
Non-metallic mineral mining	17	19	15%	16	-2%	-15%
Construction	1195	2272	90%	2100	76%	-8%
Food and kindred products	587	1857	216%	2214	277%	19%
Tobacco manufactures	34	95	183%	125	273%	32%
Textile mill products	86	409	377%	355	314%	-13%
Apparel and other textile products	81	412	411%	384	375%	-7%
Lumber and wood products	153	633	313%	549	258%	-13%
Furniture and fixtures	104	352	239%	316	204%	-10%
Paper and allied products	225	1010	348%	897	298%	-11%
Printing and publishing	253	713	182%	675	167%	-5%
Chemicals and allied products	535	2626	391%	2091	291%	-20%
Petroleum refining	307	478	55%	250	-19%	-48%
Rubber and plastic products	226	901	298%	776	243%	-14%
Leather and leather products	13	62	367%	56	324%	-9%

FMPA-POD1-00212

HEARING EXHIBIT - 00000375

Results: Scenario 2 – S. 2191

2050 Sectoral Results (Sectors 19 – 35) (IGEM)

Sector	2007	2050				
		Reference		S.2191 Scenario 2		
	Output ($Billions)	Output ($Billions)	Percent Change from 2007	Output ($Billions)	Percent Change from 2007	Percent Change from Reference
Stone, clay and glass products	121	468	287%	454	276%	-3%
Primary metals	213	768	261%	612	188%	-20%
Fabricated metal products	329	1023	211%	892	171%	-13%
Non-electrical machinery	655	4636	608%	4076	522%	-12%
Electrical machinery	465	7752	1567%	6833	1370%	-12%
Motor vehicles	532	1888	255%	1684	216%	-11%
Other transportation equipment	227	702	210%	654	188%	-7%
Instruments	261	894	242%	835	220%	-7%
Miscellaneous manufacturing	69	329	379%	304	342%	-8%
Transportation and warehousing	707	2006	184%	1808	156%	-10%
Communications	537	1920	258%	1913	256%	0%
Electric utilities (services)	399	731	83%	479	20%	-35%
Gas utilities (services)	52	67	27%	31	-41%	-54%
Wholesale and retail trade	2590	7293	182%	6713	159%	-8%
Finance, insurance and real estate	2743	10257	274%	10085	268%	-2%
Personal and business services	4468	12694	184%	12603	182%	-1%
Government enterprises	467	1297	178%	1223	162%	-6%

FMPA-POD1-00213

HEARING EXHIBIT - 00000376

Results: Scenario 10 – S. 2191 Alt. Ref.

2030 Sectoral Results (Sectors 1 – 18) (IGEM)

Sector	2007	2030				
		Alternative Reference		S.2191 Alt. Ref.		
	Output ($Billions)	Output ($Billions)	Percent Change from 2007	Output ($Billions)	Percent Change from 2007	Percent Change from Reference
Agriculture, forestry, fisheries	510	1049	106%	1103	116%	5%
Metal mining	83	165	100%	151	83%	-9%
Coal mining	30	37	22%	19	-37%	-48%
Crude oil and gas extraction	165	243	47%	210	28%	-13%
Non-metallic mineral mining	16	15	-12%	13	-19%	-8%
Construction	1190	1645	38%	1566	32%	-5%
Food and kindred products	588	1240	111%	1292	120%	4%
Tobacco manufactures	34	63	87%	68	101%	7%
Textile mill products	86	238	179%	219	156%	-8%
Apparel and other textile products	81	227	181%	219	171%	-3%
Lumber and wood products	153	346	126%	319	109%	-8%
Furniture and fixtures	103	235	127%	220	114%	-6%
Paper and allied products	225	579	157%	544	142%	-6%
Printing and publishing	252	460	82%	446	77%	-3%
Chemicals and allied products	533	1455	173%	1292	142%	-11%
Petroleum refining	305	369	21%	306	0%	-17%
Rubber and plastic products	225	574	155%	530	135%	-8%
Leather and leather products	13	35	168%	34	157%	-4%

FMPA-POD1-00214

HEARING EXHIBIT - 00000377

Results: Scenario 10 – S. 2191 Alt. Ref.

2030 Sectoral Results (Sectors 19 – 35) (IGEM)

Sector	2007	2030				
		Alternative Reference		S.2191 Alt. Ref.		
	Output ($Billions)	Output ($Billions)	Percent Change from 2007	Output ($Billions)	Percent Change from 2007	Percent Change from Reference
Stone, clay and glass products	120	261	117%	247	105%	-5%
Primary metals	211	466	120%	414	96%	-11%
Fabricated metal products	328	652	99%	602	84%	-8%
Non-electrical machinery	652	2498	283%	2311	255%	-7%
Electrical machinery	463	3429	641%	3181	588%	-7%
Motor vehicles	529	1148	117%	1066	101%	-7%
Other transportation equipment	226	439	94%	419	85%	-5%
Instruments	260	590	127%	564	117%	-4%
Miscellaneous manufacturing	68	183	168%	175	156%	-5%
Transportation and warehousing	707	1340	90%	1267	79%	-5%
Communications	537	1196	123%	1176	119%	-2%
Electric utilities (services)	396	540	36%	470	19%	-13%
Gas utilities (services)	52	61	18%	45	-13%	-26%
Wholesale and retail trade	2583	4894	90%	4677	81%	-4%
Finance, insurance and real estate	2743	6377	133%	6235	127%	-2%
Personal and business services	4468	8503	90%	8374	87%	-2%
Government enterprises	466	878	88%	849	82%	-3%

FMPA-POD1-00215

HEARING EXHIBIT - 00000378

Results: Scenario 10 – S. 2191 Alt. Ref.

2050 Sectoral Results (Sectors 1 – 18) (IGEM)

Sector	2007	2050				
		Alternative Reference			S.2191 Alt. Ref.	
	Output ($Billions)	Output ($Billions)	Percent Change from 2007	Output ($Billions)	Percent Change from 2007	Percent Change from Reference
Agriculture, forestry, fisheries	510	1561	204%	1663	226%	7%
Metal mining	83	256	211%	219	166%	-14%
Coal mining	30	46	54%	14	-52%	-69%
Crude oil and gas extraction	165	328	99%	242	47%	-26%
Non-metallic mineral mining	16	19	15%	16	0%	-13%
Construction	1190	2279	92%	2111	77%	-7%
Food and kindred products	588	1933	229%	2179	271%	13%
Tobacco manufactures	34	101	200%	122	264%	21%
Textile mill products	86	408	377%	361	321%	-12%
Apparel and other textile products	81	413	412%	386	379%	-6%
Lumber and wood products	153	636	316%	555	264%	-13%
Furniture and fixtures	103	352	241%	318	208%	-10%
Paper and allied products	225	1014	351%	905	303%	-11%
Printing and publishing	252	717	184%	678	169%	-6%
Chemicals and allied products	533	2628	393%	2137	301%	-19%
Petroleum refining	305	433	42%	265	-13%	-39%
Rubber and plastic products	225	906	302%	786	249%	-13%
Leather and leather products	13	62	368%	57	329%	-8%

FMPA-POD1-00216

HEARING EXHIBIT - 00000379

Results: Scenario 10 – S. 2191 Alt. Ref.

2050 Sectoral Results (Sectors 19 – 35) (IGEM)

Sector	2007	2050				
		Alternative Reference		S.2191 Alt. Ref.		
	Output ($Billions)	Output ($Billions)	Percent Change from 2007	Output ($Billions)	Percent Change from 2007	Percent Change from Reference
Stone, clay and glass products	120	474	294%	454	277%	-4%
Primary metals	211	768	263%	623	195%	-19%
Fabricated metal products	328	1027	213%	901	175%	-12%
Non-electrical machinery	652	4672	617%	4114	531%	-12%
Electrical machinery	463	7819	1590%	6896	1390%	-12%
Motor vehicles	529	1904	260%	1698	221%	-11%
Other transportation equipment	226	707	213%	657	191%	-7%
Instruments	260	897	245%	838	222%	-7%
Miscellaneous manufacturing	68	331	383%	306	347%	-8%
Transportation and warehousing	707	2018	186%	1824	158%	-10%
Communications	537	1946	263%	1913	256%	-2%
Electric utilities (services)	396	687	74%	497	25%	-28%
Gas utilities (services)	52	64	24%	33	-36%	-48%
Wholesale and retail trade	2583	7301	183%	6757	162%	-7%
Finance, insurance and real estate	2743	10389	279%	10090	268%	-3%
Personal and business services	4468	12831	187%	12611	182%	-2%
Government enterprises	466	1302	179%	1229	164%	-6%

FMPA-POD1-00217

HEARING EXHIBIT - 00000380

Results: Scenario 2 – S. 2191

International Trade Leakage – All Sectors (ADAGE)

Change in Trade Quantities		Scenario 2 - S.2191				
		2010	2020	2030	2040	2050
Agriculture	U.S. Imports from Group 1	2.5%	3.5%	2.4%	3.4%	5.6%
	U.S. Exports to Group 1	-4.1%	-5.2%	-5.3%	-7.6%	-8.9%
	U.S. Imports from Group 2	-2.7%	-6.2%	4.0%	5.7%	7.8%
	U.S. Exports to Group 2	5.4%	10.4%	5.4%	6.1%	5.4%
Energy-Intensive Manufacturing	U.S. Imports from Group 1	0.1%	-0.2%	-0.9%	0.1%	1.6%
	U.S. Exports to Group 1	-1.1%	-1.0%	1.8%	1.9%	2.3%
	U.S. Imports from Group 2	-4.7%	-8.7%	6.6%	12.0%	13.6%
	U.S. Exports to Group 2	5.0%	9.4%	0.6%	-2.2%	-4.4%
Other Manufacturing	U.S. Imports from Group 1	-1.8%	-2.6%	-3.7%	-3.8%	-3.7%
	U.S. Exports to Group 1	1.1%	-0.3%	0.5%	0.7%	1.6%
	U.S. Imports from Group 2	-3.4%	-4.5%	-0.3%	2.6%	2.9%
	U.S. Exports to Group 2	4.5%	7.9%	7.0%	6.4%	4.9%
Services	U.S. Imports from Group 1	-1.6%	-1.1%	-2.1%	-2.4%	-2.5%
	U.S. Exports to Group 1	0.3%	-0.1%	-0.8%	-0.6%	-0.2%
	U.S. Imports from Group 2	-3.3%	-4.0%	-3.0%	-0.4%	0.7%
	U.S. Exports to Group 2	4.5%	6.5%	9.8%	9.1%	7.9%
Transportation Services	U.S. Imports from Group 1	0.9%	-3.8%	-4.7%	-6.6%	-9.9%
	U.S. Exports to Group 1	2.5%	3.8%	6.4%	9.1%	12.6%
	U.S. Imports from Group 2	-6.0%	-13.5%	-1.3%	3.1%	4.8%
	U.S. Exports to Group 2	4.9%	14.4%	12.3%	13.0%	11.5%

FMPA-POD1-00218

HEARING EXHIBIT - 00000381

Results: Scenario 3 – S. 2191, Alternative International Action
International Trade Leakage – All Sectors (ADAGE)

Change in Trade Quantities		Scenario 3 - Alternative International Action				
		2010	2020	2030	2040	2050
Agriculture	U.S. Imports from Group 1	1.7%	1.0%	0.9%	-1.9%	-5.5%
	U.S. Exports to Group 1	-2.4%	-1.4%	-1.5%	0.0%	2.2%
	U.S. Imports from Group 2	-1.6%	-3.7%	-4.7%	-6.5%	-9.3%
	U.S. Exports to Group 2	3.2%	5.6%	6.8%	7.5%	8.8%
Energy-Intensive Manufacturing	U.S. Imports from Group 1	0.3%	-1.0%	-1.7%	-3.4%	-6.3%
	U.S. Exports to Group 1	-0.7%	0.6%	0.8%	1.5%	2.7%
	U.S. Imports from Group 2	-3.0%	-3.7%	-1.5%	2.2%	5.5%
	U.S. Exports to Group 2	3.1%	5.3%	6.3%	6.7%	7.7%
Other Manufacturing	U.S. Imports from Group 1	-0.6%	-0.8%	-1.3%	-1.8%	-3.4%
	U.S. Exports to Group 1	0.8%	1.3%	1.6%	1.6%	1.9%
	U.S. Imports from Group 2	-2.1%	-2.4%	-2.4%	-1.9%	-2.3%
	U.S. Exports to Group 2	2.4%	3.5%	4.4%	4.9%	5.4%
Services	U.S. Imports from Group 1	-1.0%	-0.3%	-0.5%	-0.3%	-0.8%
	U.S. Exports to Group 1	0.2%	0.3%	0.6%	0.4%	0.4%
	U.S. Imports from Group 2	-1.7%	-1.5%	-1.9%	-1.9%	-2.3%
	U.S. Exports to Group 2	2.8%	3.3%	3.9%	4.2%	4.5%
Transportation Services	U.S. Imports from Group 1	0.0%	-5.3%	-4.3%	-8.1%	-15.6%
	U.S. Exports to Group 1	-1.5%	5.4%	9.2%	13.7%	18.4%
	U.S. Imports from Group 2	-4.0%	-9.9%	-10.4%	-13.6%	-20.0%
	U.S. Exports to Group 2	2.9%	10.5%	15.2%	19.3%	23.4%

FMPA-POD1-00219
HEARING EXHIBIT - 00000382

Results: Scenario 8 – S. 2191, Constrained Nuclear, Biomass and CCS + Beyond Kyoto + Natural Gas Cartel

International Trade Leakage – All Sectors (ADAGE)

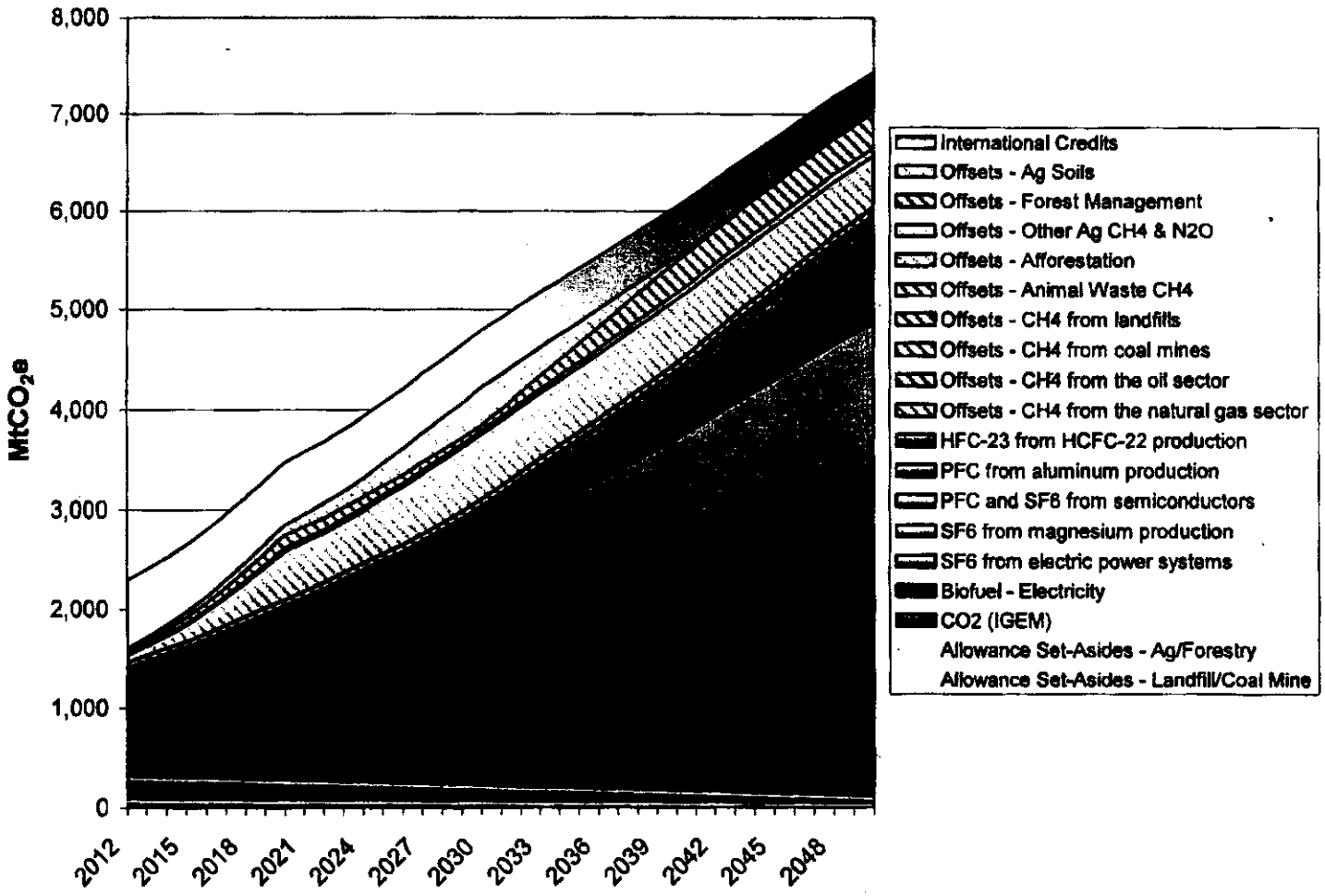
Scenario 8 - S. 2191 Constrain Nuclear, Biomass, CCS, Beyond Kyoto, and Natural Gas Cartel						
Change in Trade Quantities		2010	2020	2030	2040	2050
Agriculture	U.S. Imports from Group 1	3.9%	6.3%	6.2%	8.3%	10.7%
	U.S. Exports to Group 1	-5.1%	-6.3%	-6.8%	-9.6%	-11.9%
	U.S. Imports from Group 2	-2.9%	-6.3%	8.3%	11.0%	13.7%
	U.S. Exports to Group 2	6.6%	13.2%	5.9%	6.9%	7.1%
Energy-Intensive Manufacturing	U.S. Imports from Group 1	0.7%	0.2%	-0.3%	0.4%	1.0%
	U.S. Exports to Group 1	-1.4%	-0.6%	2.8%	3.9%	5.2%
	U.S. Imports from Group 2	-5.8%	-11.5%	8.3%	14.2%	19.2%
	U.S. Exports to Group 2	6.1%	12.7%	1.6%	-1.3%	-4.3%
Other Manufacturing	U.S. Imports from Group 1	-2.0%	-2.7%	-3.9%	-4.6%	-5.8%
	U.S. Exports to Group 1	1.7%	-0.1%	0.5%	1.6%	3.3%
	U.S. Imports from Group 2	-3.8%	-5.0%	0.6%	3.6%	5.5%
	U.S. Exports to Group 2	5.7%	10.8%	9.9%	9.0%	7.8%
Services	U.S. Imports from Group 1	-2.0%	-0.7%	-1.6%	-2.1%	-3.3%
	U.S. Exports to Group 1	0.8%	0.4%	-0.8%	-0.3%	0.9%
	U.S. Imports from Group 2	-4.3%	-4.8%	-3.2%	-0.4%	2.4%
	U.S. Exports to Group 2	5.4%	8.5%	13.0%	12.6%	11.3%
Transportation Services	U.S. Imports from Group 1	1.6%	-7.2%	-11.5%	-16.0%	-21.1%
	U.S. Exports to Group 1	-2.8%	8.1%	10.8%	15.4%	22.2%
	U.S. Imports from Group 2	-6.9%	-20.1%	-6.3%	-2.9%	1.5%
	U.S. Exports to Group 2	6.0%	21.0%	17.4%	19.0%	21.1%

FMPA-POD1-00220

HEARING EXHIBIT - 00000383

Results: S. 2191 – Unlimited Domestic Offsets, Limited Int'l Credits

Sources of GHG Abatement (IGEM)

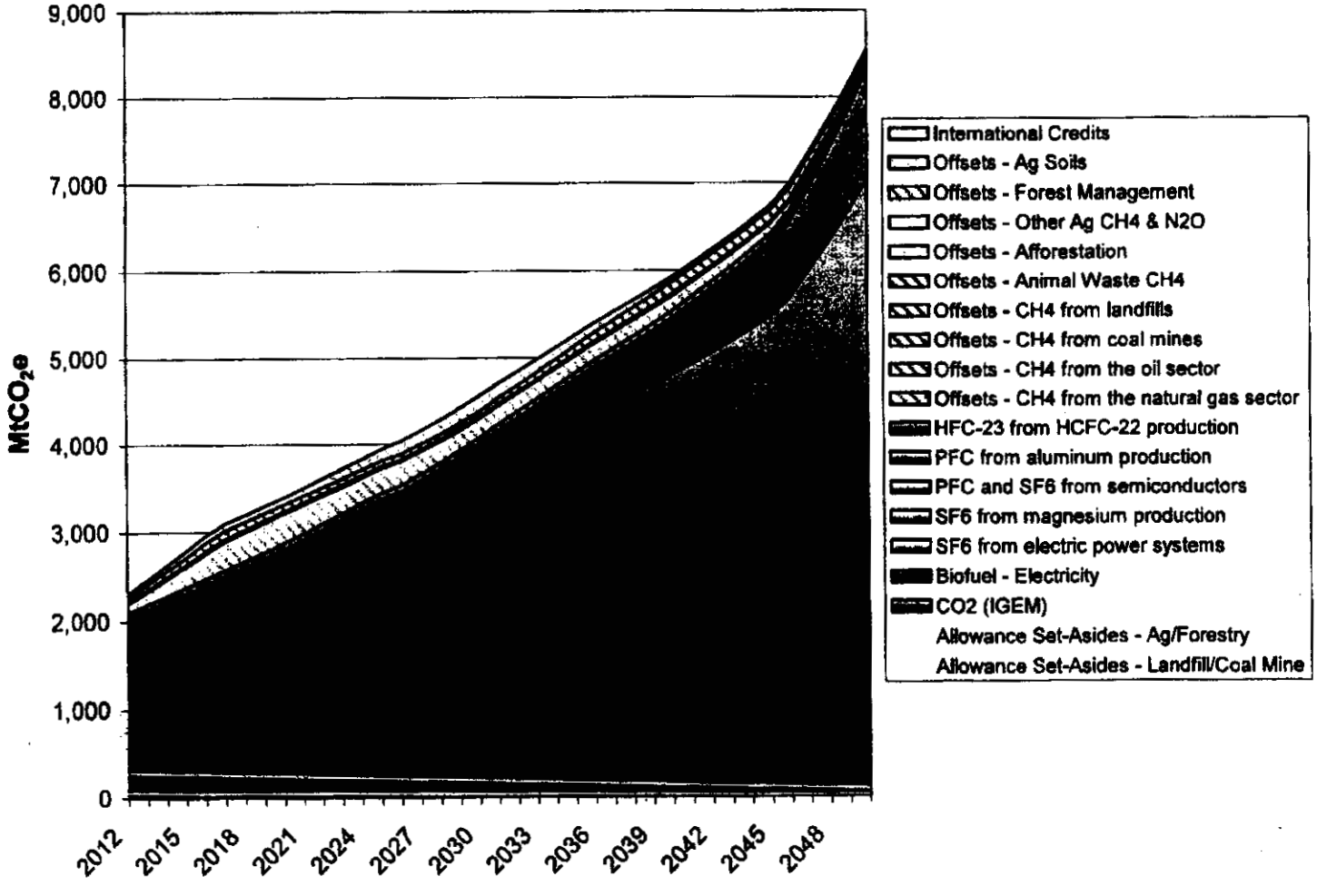


FMPA-POD1-00221

HEARING EXHIBIT - 00000384

Results: S. 2191 – Limited Domestic Offsets, No Int'l Credits

Sources of GHG Abatement (IGEM)



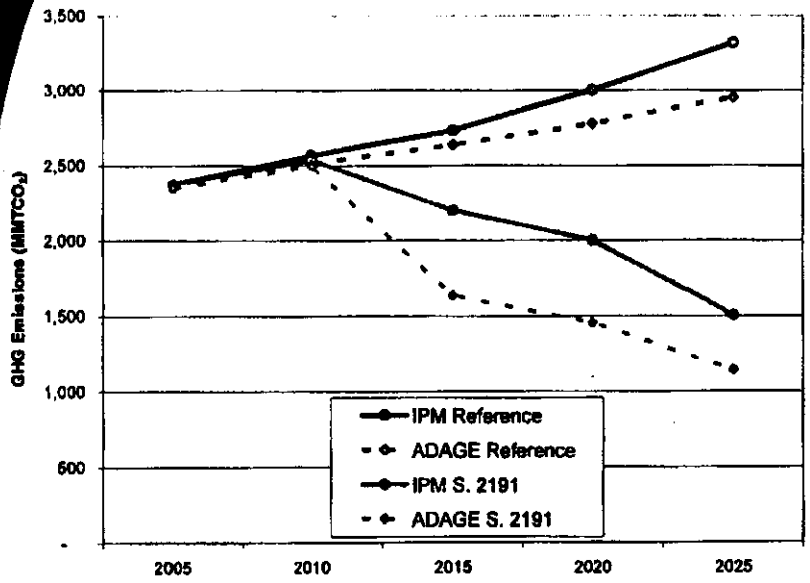
EPA Analysis of S. 2191

FMPA-POD1-00222

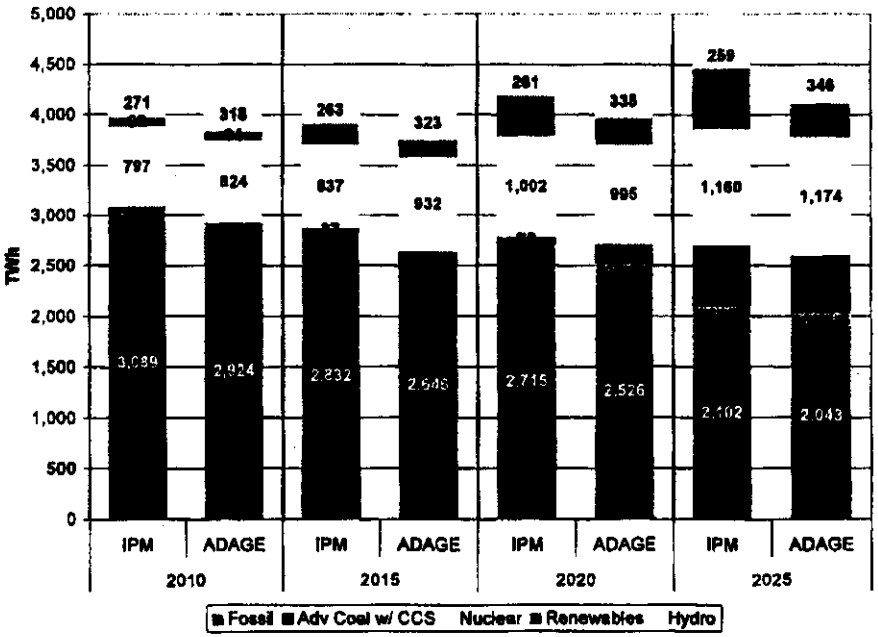
HEARING EXHIBIT - 00000385

ADAGE & IPM Comparison of Power Sector Results

Power Sector CO_2 Emissions



S. 2191 Scenario Electricity Generation Mix

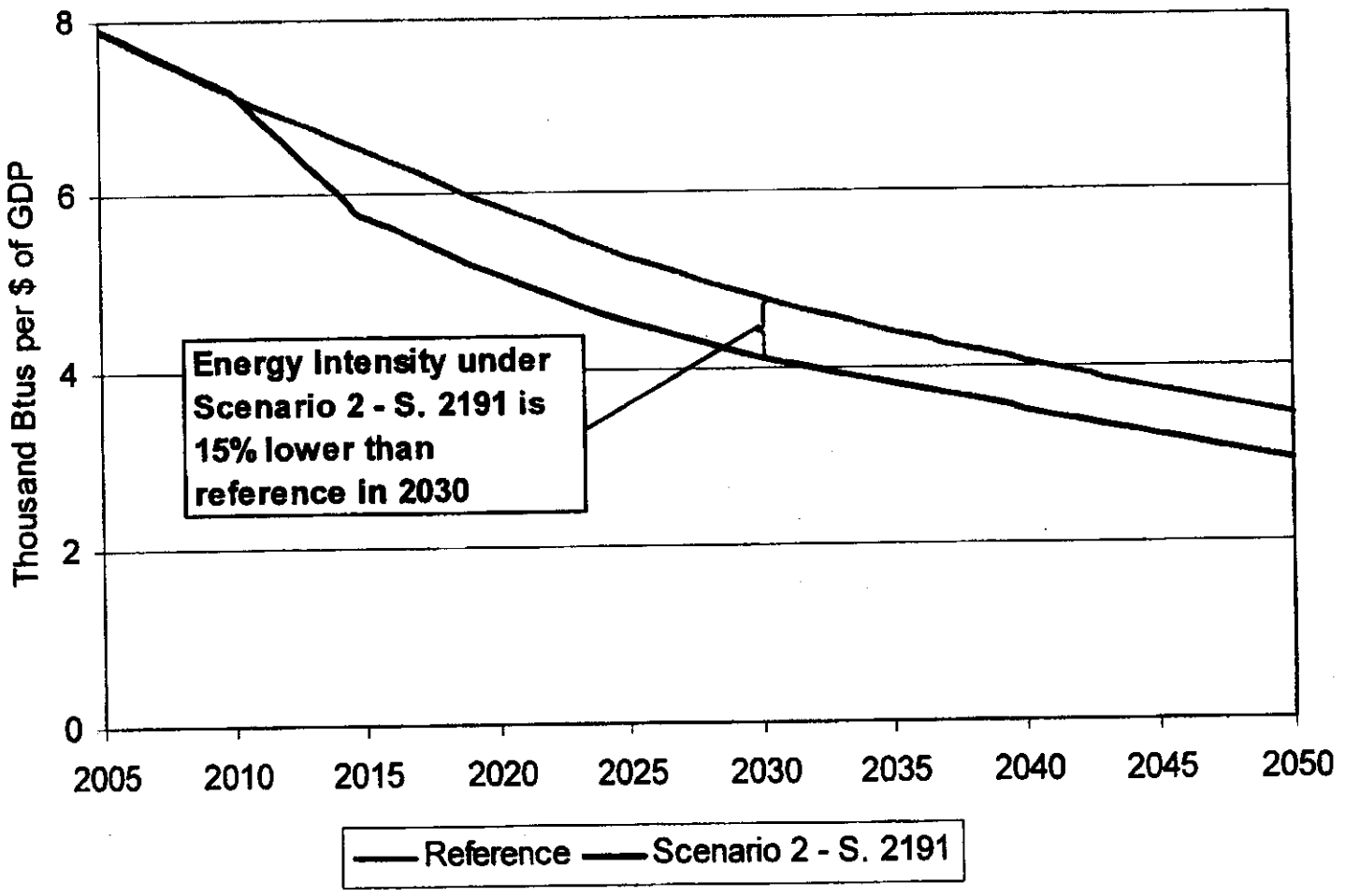


- The ADAGE reference emissions are somewhat lower than IPM, and emission reductions under S. 2191 are greater prior to 2025.
- Electricity generation mix projections are similar, with slightly lower overall electricity demand in ADAGE compared to IPM and lower renewable generation.

FMPA-POD1-00223
HEARING EXHIBIT - 00000386

Results: Scenario 2 – S. 2191

Energy Intensity (ADAGE)

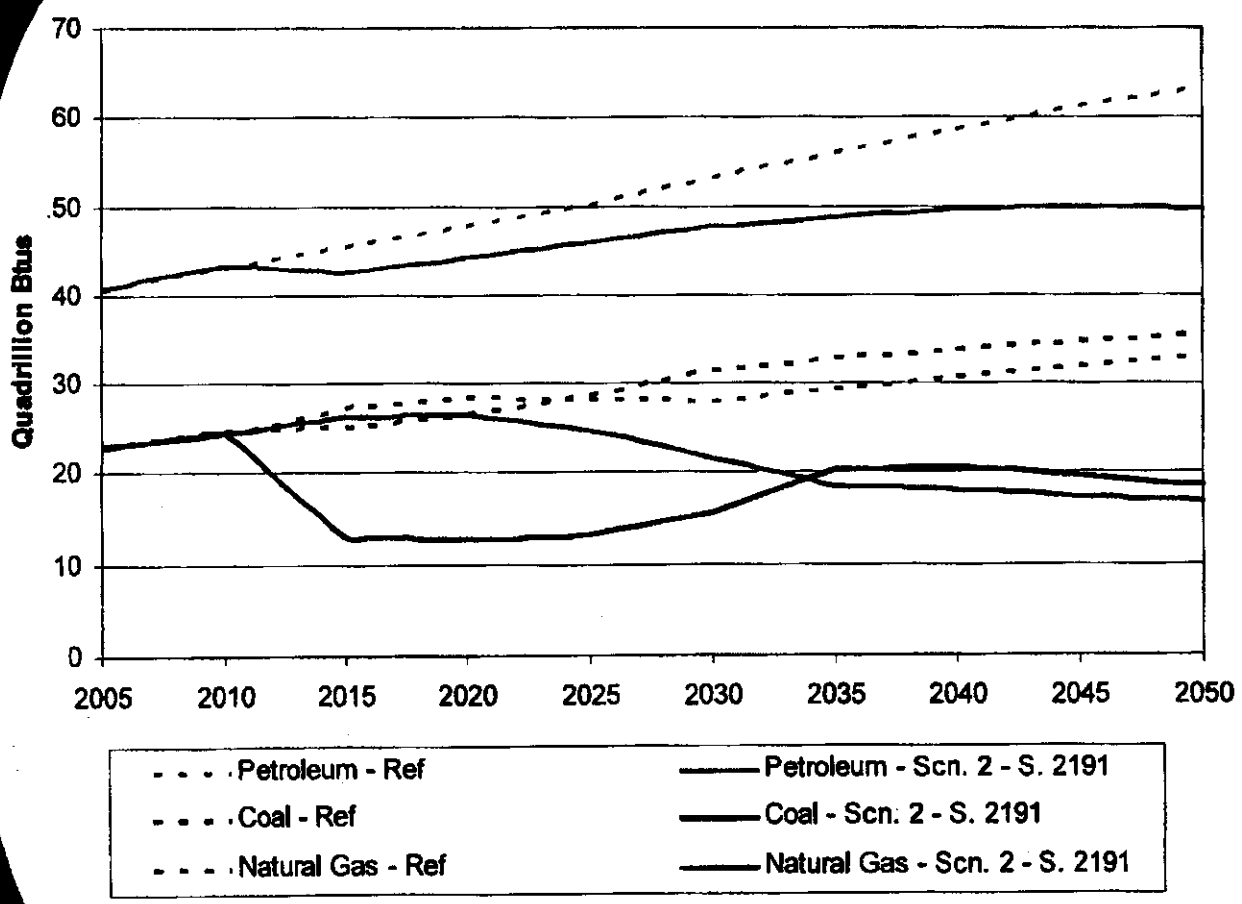


FMPA-POD1-00224

HEARING EXHIBIT - 00000387

Results: Scenario 2 – S. 2191

Primary Energy Use (ADAGE)



- Growth in petroleum use is less under S. 2191 than in the Reference Scenario.
- Coal use falls as S. 2191 is implemented and fuel-switching to natural gas occurs, then rises again in the later years as advanced coal plants with CCS are deployed.
  - Note that the IPM analysis shows a much smaller impact on near-term coal usage.
- The natural gas use trend follows an opposite path to the coal use trend. Natural gas use increases in the earlier years as fuel-switching occurs, and then falls in the later years as CCS is deployed.

FMPA-POD1-00225

HEARING EXHIBIT - 00000388

Appendix 5: Request Letters

FMPA-POD1-00226

HEARING EXHIBIT - 00000389

Request for EPA Analysis

United States Senate

WASHINGTON, DC 20510

November 9, 2007

The Honorable Stephen L. Johnson
Administrator
Environmental Protection Agency
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Dear Administrator Johnson:

We are writing to request that EPA estimate the economic, greenhouse-gas emissions, and atmospheric greenhouse-gas concentration impacts of S.2191, America's Climate Security Act of 2007. A similar request is being sent to the Energy Information Administration.

We ask that EPA begin this process by meeting with our staff as soon as possible to discuss the parameters, methods, and duration of the analysis. Please call David McIntosh in Senator Lieberman's office at (202) 224-5016 or Chelsea Maxwell in Senator Warner's office at (202) 224-6283.

Thank you for your assistance with this analysis.

Sincerely,

Joseph I. Lieberman
UNITED STATES SENATOR

John Warner
UNITED STATES SENATOR

- On November 9, 2007 Senators Lieberman and Warner requested that EPA estimate the economic impacts of the S. 2191, the 'Climate Security Act of 2007' (now the 'Lieberman-Warner Climate Security Act of 2008').
- This document constitutes EPA's analysis in response to this request. The analysis is available online at:

www.epa.gov/climatechange/economics/economicanalyses.html

- The analysis was conducted by EPA's Office of Atmospheric Programs.
  Contact: Francisco de la Chesnaye.
  Tel: 202-343-9010.
  Email: delachesnaye.francisco@epa.gov.

FMPA-POD1-00227

HEARING EXHIBIT - 00000390

United States Senate

WASHINGTON, DC 20510

October 5, 2007

The Honorable Stephen L. Johnson
Administrator
Environmental Protection Agency
Ariel Rios Federal Building
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Dear Mr. Johnson:

As Congress considers policies to address global climate change, the need for robust, objective, and well-grounded technical analysis of the impacts those policies will have on the American economy is imperative. We applaud the Environmental Protection Agency (EPA) for providing credible historical analyses over the years. However, we are concerned that, in its current forecasts, EPA is not considering realistic scenarios of our nation's energy future, and as a result, is not providing an accurate picture of the potential consequences arising from mandatory greenhouse gas emission controls.

As you are well aware, concern about climate change has reinforced opposition in some quarters against certain types of energy production. This seems to be especially true of coal, as the prospects for building new coal-fired power plants look increasingly dire.

The same seems to be true of natural gas, particularly whether producers will have access to domestic supplies. Moreover, opposition to construction of new liquefied natural gas terminals and expansion of domestic production and pipelines, international greenhouse gas mandates, and geopolitical instability also present serious risks for U.S. natural gas supplies. For example, talks of additional carbon reductions beyond those required by the Kyoto Protocol could severely constrain the global natural gas market, while recent news of a possible natural gas cartel between Russia and Iran greatly complicates an already bleak future for U.S. natural gas imports.

In addition, concern about climate change has sparked a renewed interest in nuclear power as a viable alternative to fossil fuels. Yet despite greater acceptance of this important, emissions-free energy resource, nuclear power still faces a host of obstacles and uncertainties that, if unresolved, could inhibit its expansion and prevent the construction of new plants.

These issues raise serious questions as to whether and how this country will meet growing energy demand while complying with constraints on carbon emissions. As such, we are requesting that your agency reanalyze S. 280, "The Climate Stewardship and Innovation Act of 2007," by taking these realities into account. Moreover, we are requesting that your agency factor these realities into *all future analyses of mandatory climate change legislation you undertake.*

Specifically, the reanalysis of S. 280 and all future analyses of climate legislation — including S. 1766, the Low Carbon Economy Act, which I understand you are analyzing now - must include an assessment of the factors outlined in the three following scenarios:

An Alternative Policy Case assuming:

- Nuclear power does not exceed AEO 2007 Reference Case growth through 2030 (increase of 12.5 GWs);
- Biomass power does not exceed AEO 2007 Reference Case growth through 2030 (increase of 64 Billion KWhrs).

Please refer to this alternative policy case as: Reference Nuclear and Biomass Power.

An Alternative Policy Case assuming the Reference Nuclear and Biomass Power case above and assuming:

- Carbon capture and sequestration technology does not become commercially available until 2030;

Please refer to this alternative policy analysis as: Constrained CCS.

An Alternative Policy Case assuming all of the above (Reference Nuclear and Biomass Power and Constrained CCS) and assuming:

- That GHG caps are implemented for all Kyoto Protocol Annex 1 signatory countries and are reduced to 20% below 1990 levels in 2020 and to 80% below 1990 levels in 2050; and
- A functioning natural gas cartel, using the same basic modeling approach used in EIA's assessments of the Organization of the Petroleum Exporting Countries (OPEC) operations.

Please refer to this alternative policy analysis as: Beyond Kyoto Plus Natural Gas Cartel.

The July 2007 EPA analysis of S. 280, the Climate Stewardship and Innovation Act of 2007, identified a number of concerns and key assumptions as well as a number of different models used.

Please provide a description of the model or models that EPA uses to:

1. Determine the marginal abatement curves for greenhouse gases, including CO2;
2. The domestic supply and prices of natural gas;
3. The global supply and prices of natural gas;
4. The deployment of technologies, including advanced coal technologies and carbon capture and storage;
5. The economic impact of policy options at the regional and local level; and
6. The economic impact of policy options out to 2050.

FMPA-PODI-00228

HEARING EXHIBIT - 00000391

For the documentation above please provide information on the compliance of any model used with the EPA's guidelines under Federal Data Quality Guidelines, including model validation by comparing past natural gas forecasts with real data. Also, provide appropriate documentation on these models prepared by EPA's Council for Regulatory Environmental Modeling.

Please provide a detailed comparison between EPA's reference case and EIA's AEO 2007 Reference Case. If EPA has run its models for any constrained natural gas supply case, e.g. comparable to the AEO 2007 Low LNG Case, please provide the data.

Finally, in the recent EIA analysis of S 280 there was reference to use of analysis by MIT. Please explain the extent to which EPA used MIT analysis in providing support for the EIA analysis.

An expedited process would be greatly appreciated as a credible analysis is critical to a well-informed debate concerning climate change and related energy policy choices now before Congress. Either Todd Johnston (202-224-9325), or John Shanahan (202-224-6176), is available to work with you to clarify any issues. Thank you for your attention to this.

Sincerely,

James M. Inhofe
United States Senator

George V. Voinovich
United States Senator

John Barrasso
United States Senator

FMPA-POD1-00229
HEARING EXHIBIT - 00000392

United States Senate

WASHINGTON, DC 20510

November 16, 2007

The Honorable Stephen L. Johnson
Administrator
Environmental Protection Agency
Ariel Rios Federal Building
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Dear Mr. Johnson:

This is a supplemental request to our letter of October 5, 2007 requesting additional analysis of S. 280. We are anxious to receive your response to that letter.

Another proposal to limit greenhouse gas emissions, S. 2191, has been introduced. We understand that Senators Lieberman and Warner requested EPA analysis of their bill and we wanted to assure that your evaluation addressed all interests, and is as comprehensive as possible.

Therefore, in addition to the alternative scenarios outlined in our previous correspondence, we are requesting that your agency provide analysis of S. 2191 using some of the assumptions in your analysis of S. 280. The assumptions are as follows:

Non-Policy Cases:

Reference: Reference case used in the S 280 analysis.

Low LNG Case and Global Carbon Constraint:

- LNG import terminals are limited to those operational by the end of 2008,
- GHG caps are implemented for ALL Kyoto Protocol Annex 1 signatory countries and are reduced to 20% below 1990 levels in 2020 and on a trajectory to 80% below 1990 levels in 2050; and
- A functioning natural gas cartel that can extract natural gas prices equivalent to the energy content parity with Low Sulfur Light imported crude.

Policy Cases:

- The policy cases should include the Core S. 2191 case, the no international offsets case, and the 30 percent fixed offset case patterned after your S 280 analysis.

Alternative Policy Cases:

Your analysis of S. 2191 should include an assessment of the factors outlined in the two following scenarios:

An Alternative Policy Case assuming:

- Nuclear power does not exceed AEO 2007 Reference Case growth through 2030; and
- Biomass power does not exceed AEO 2007 Reference Case growth through 2030.

Please refer to this alternative policy case as: Reference Nuclear and Biomass Power (RefNB).

An Alternative Policy Case assuming the Reference Nuclear and Biomass Power case above and assuming:

- Carbon capture and sequestration technology does not become commercially available until 2030;

Please refer to this alternative policy analysis as: Constrained CCS (RefNB+noCCS).

We have attached a table that summarizes these cases.

In addition, since the costs of greenhouse gas controls escalate over time, an accurate account for the impacts between 2030 and 2050 is required. Therefore, in your analysis of S. 2191, please provide estimates of the economic impacts for the period 2030-2050 including the aggregate loss of GDP for the periods 2008-2030, 2030-2050, and 2008-2050.

EPA should also provide natural gas, electricity, and economic impact data at the state and regional level.

FMPA-POD1-00230

HEARING EXHIBIT - 00000393

An expedited process of this request is appreciated; we expect the results to be released in conjunction with the information provided in response to the request of Senators Lieberman and Warner. Todd Johnston (202-224-9325) and John Shanahan (202-224-8072) are available to work with you to clarify any issues. Thank you for your prompt attention to our request.

Sincerely,

James M. Inhofe
United States Senator

George V. Voinovich
United States Senator

John Barrasso
United States Senator

FMPA-POD1-00231

HEARING EXHIBIT - 00000394



Appendix 6: Model Descriptions

FMPA-POD1-00232

HEARING EXHIBIT - 00000395

Intertemporal General Equilibrium Model (IGEM)

- IGEM is a model of the U.S. economy with an emphasis on the energy and environmental aspects.
- It is a dynamic model, which depicts growth of the economy due to capital accumulation, technical change and population change.
- It is a detailed multi-sector model covering 35 industries.
- It also depicts changes in consumption patterns due to demographic changes, price and income effects.
- The model is designed to simulate the effects of policy changes, external shocks and demographic changes on the prices, production and consumption of energy, and the emissions of pollutants.
- The main driver of economic growth in this model is capital accumulation and technological change. It also includes official projections of the population, giving us activity levels in both level and per-capita terms.
- Capital accumulation arises from savings of a household that is modeled as an economic actor with "perfect foresight."
- This model is implemented econometrically which means that the parameters governing the behavior of producers and consumers are statistically estimated over a time series dataset that is constructed specifically for this purpose.
- This is in contrast to many other multi-sector models that are calibrated to the economy of one particular year.
- These data are based on a system of national accounts developed by Jorgenson (1980) that integrates the capital accounts with the National Income Accounts.
- These capital accounts include an equation linking the price of investment goods to the stream of future rental flows, a link that is essential to modeling the dynamics of growth.
- The model is developed and run by Dale Jorgenson Associates for EPA.
- Model Homepage: http://post.economics.harvard.edu/faculty/jorgenson/papers/papers.html

FMPA-POD1-00233
HEARING EXHIBIT - 00000396

Applied Dynamic Analysis of the Global Economy (ADAGE)

- ADAGE is a dynamic computable general equilibrium (CGE) model capable of examining many types of economic, energy, environmental, climate-change mitigation, and trade policies at the international, national, U.S. regional, and U.S. state levels.
- To investigate policy effects, the CGE model combines a consistent theoretical structure with economic data covering all interactions among businesses and households.
- A classical Arrow-Debreu general equilibrium framework is used to describe economic behaviors of these agents.

- ADAGE has three distinct modules: International, U.S. Regional, and Single Country.
- Each module relies on different data sources and has a different geographic scope, but all have the same theoretical structure.
- This internally consistent, integrated framework allows its components to use relevant policy findings from other modules with broader geographic coverage, thus obtaining detailed regional and state-level results that incorporate international impacts of policies.
- Economic data in ADAGE come from the GTAP and IMPLAN databases, and energy data and various growth forecasts come from the International Energy Agency and Energy Information Administration of the U.S. Department of Energy.
- Emissions estimates and associated abatement costs for six types of greenhouse gases (GHGs) are also included in the model.

- The model is developed and run by RTI International for EPA.
- Model Homepage: http://www.rti.org/adage

FMPA-POD1-00234
HEARING EXHIBIT - 00000397

Non-CO_2 GHG Models

- EPA develops and houses projections and economic analyses of emission abatement through the use of extensive bottom-up, spreadsheet models.
- These are engineering–economic models capturing the relevant cost and performance data on over 15 sectors emitting the non-CO_2 GHGs.
- For the emissions inventory and projections, all anthropogenic sources are covered. For mitigation of methane, the sources evaluated include coal mining, natural gas systems, oil production, and solid waste management.
- For mitigation of HFC, PFC, and SF6, the sources evaluated include over 12 industrial sectors.
- For mitigation of nitrous oxide, sources evaluated include adipic and nitric acid production.
- Only currently available or close-to-commercial technologies are evaluated.
- The estimated reductions and costs are assembled into marginal abatement curves (MACs).
- MACs are straightforward, informative tools in policy analyses for evaluating economic impacts of GHG mitigation. A MAC illustrates the amount of reductions possible at various values for a unit reduction of GHG emissions and is derived by rank ordering individual opportunities by cost per unit of emission reduction. Any point along a MAC represents the marginal cost of abating an additional amount of a GHG.
- The total cost of meeting an absolute emission reduction target can be estimated by taking the integral of a MAC curve from the origin to the target.
- Global mitigation estimates are available aggregated into nine major regions of the world including the U.S. and are reported for the years 2010, 20015 and 2020.
- The data used in the report are from *Global Mitigation of Non-CO_2 Greenhouse Gases* (EPA Report 430-R-06-005). www.epa.gov/nonco2/econ-inv/international.html

FMPA-POD1-00235
HEARING EXHIBIT - 00000398

Forest and Agriculture Sector Optimization Model-GHG

- FASOM-GHG simulates land management and land allocation decisions over time to competing activities in both the forest and agricultural sectors. In doing this, it simulates the resultant consequences for the commodity markets supplied by these lands and, importantly for policy purposes, the net greenhouse gas (GHG) emissions.
- The model was developed to evaluate the welfare and market impacts of public policies and environmental changes affecting agriculture and forestry. To date, FASOMGHG and its predecessor models FASOM and ASM have been used to examine the effects of GHG mitigation policy, climate change impacts, public timber harvest policy, federal farm program policy, biofuel prospects, and pulpwood production by agriculture among other policies and environmental changes.
- FASOMGHG is a multiperiod, intertemporal, price-endogenous, mathematical programming model depicting land transfers and other resource allocations between and within the agricultural and forest sectors in the US. The model solution portrays simultaneous market equilibrium over an extended time, typically 70 to 100 years on a ten year time step basis.
- The results from FASOMGHG yield a dynamic simulation of prices, production, management, consumption, GHG effects, and other environmental and economic indicators within these two sectors, under the scenario depicted in the model data.
- The principal model developer is Dr. Bruce McCarl, Department of Agricultural Economics, Texas A&M University.
- The data used in the report are from *Greenhouse Gas Mitigation Potential in U.S. Forestry and Agriculture* (EPA Report 430-R-05-006). http://www.epa.gov/sequestration/greenhouse_gas.html.
- Model Homepage: http://agecon2.tamu.edu/people.faculty/mccarl-bruce/FASOM.html

EMPA-POD1-00236

HEARING EXHIBIT - 00000399

Global Timber Model (GTM)

- GTM is an economic model capable of examining global forestry land-use, management, and trade responses to policies. In responding to a policy, the model captures afforestation, forest management, and avoided deforestation behavior.
- The model estimates harvests in industrial forests and inaccessible forests, timberland management intensity, and plantation establishment, all important components of both future timber supply and carbon flux. The model also captures global market interactions.
- The model is a partial equilibrium intertemporally optimizing model that maximizes welfare in timber markets over time across approximately 250 world timber supply regions by managing forest stand ages, compositions, and acreage given production and land rental costs. The model equates supply and demand in each period, and predicts supply responses to current and future prices. The 250 supply regions are delineated by ecosystem and timber management classes, as well as geo-political regional boundaries. The model runs on 10-year time steps.
- The model has been used to explore a variety of climate change mitigation policies, including carbon prices, stabilization, and optimal mitigation policies.
- The principal model developer is Brent Sohngen, Department of Agricultural, Environmental, and Development Economics, Ohio State University. Other key developers and collaborators over the life of the model include Robert Mendelsohn, Roger Sedjo, and Kenneth Lyon. For this analysis, the model was run by Dr. Sohngen for EPA.
- Website for GTM papers and input datasets: http://aede.osu.edu/people/sohngen.1/forests/ccforest.htm#gfmod

FMPA-POD1-00237
HEARING EXHIBIT - 00000400

Mini-Climate Assessment Model (MiniCAM)

- The MiniCAM is a highly aggregated integrated assessment model that focuses on the world's energy and agriculture systems, atmospheric concentrations of greenhouse gases (CO_2 and non-CO_2) and sulfur dioxide, and consequences regarding climate change and sea level rise.
- It has been updated many times since the early eighties to include additional technology options. MiniCAM is capable of incorporating carbon taxes and carbon constraints in conjunction with the numerous technology options including carbon capture and sequestration.
- The model has been exercised extensively to explore how the technology gap can be filled between a business-as-usual emissions future and an atmospheric stabilization scenario.
- The MiniCAM model is designed to assess various climate change policies and technology strategies for the globe over long time scales. It is configured as a partial equilibrium model that balances supply and demand for commodities such as oil, gas, coal, biomass and agricultural products.
- The model runs in 15-year time steps from 1990 to 2095 and includes 14 geographic regions.
- The model is developed and run at the Joint Global Change Research Institute, University of Maryland. Model Homepage: http://www.globalchange.umd.edu

FMPA-POD1-00238

HEARING EXHIBIT - 00000401

The Integrated Planning Model (IPM)

- EPA uses the Integrated Planning Model (IPM) to analyze the projected impact of environmental policies on the electric power sector in the 48 contiguous states and the District of Columbia.
- IPM is a multi-regional, dynamic, deterministic linear programming model of the U.S. electric power sector.
- The model provides forecasts of least-cost capacity expansion, electricity dispatch, and emission control strategies for meeting energy demand and environmental, transmission, dispatch, and reliability constraints.
- IPM can be used to evaluate the cost and emissions impacts of proposed policies to limit emissions of sulfur dioxide (SO_2), nitrogen oxides (NOx), carbon dioxide (CO_2), and mercury (Hg) from the electric power sector.
- The IPM was a key analytical tool in developing the Clean Air Interstate Regulation (CAIR) and the Clean Air Mercury Rule (CAMR).
- IPM provides both a broad and detailed analysis of control options for major emissions from the power sector, such as power generation adjustments, pollution control actions, air emissions changes (national, regional/state, and local), major fuel use changes, and economic impacts (costs, wholesale electricity prices, closures, allowance values, etc.).
- The model was developed by ICF Resources and is applied by EPA for its Base Case. IPM® is a registered trademark of ICF Resources, Inc.
- EPA's application of IPM Homepage: http://www.epa.gov/airmarkets/progsregs/epa-ipm/index.html

FMPA-POD1-00239

HEARING EXHIBIT - 00000402

National Energy Modeling System (NEMS)

- When Senators Lieberman and McCain requested that EPA analyze S. 280, they sent a similar request to the Energy Information Administration (EIA).
- EIA is using NEMS for its analysis of S. 280.
- NEMS is also used to produce the Annual Energy Outlook (AEO).
- NEMS represents domestic energy markets by explicitly representing the economic decision making involved in the production, conversion, and consumption of energy products.
- Where possible, NEMS includes explicit representation of energy technologies and their characteristics.
- NEMS is organized and implemented as a modular system.
  - For each fuel and consuming sector, NEMS balances the energy supply and demand, accounting for the economic competition between the various energy fuels and sources.
  - The modules represent each of the fuel supply markets, conversion sectors, and end-use consumption sectors of the energy system.
  - NEMS also includes a macroeconomic and an international module.
  - For purposes of S.280 analysis, NEMS is augmented with a representation of greenhouse gas emissions outside of the energy sector and uses marginal abatement curves to represent opportunities to reduce them.
- NEMS includes regional detail (nine Census divisions).
- NEMS runs in annual time steps through 2030.

FMPA-POD1-00240

HEARING EXHIBIT - 0000403

Differences between NEMS and IGEM / ADAGE

- Analysis Time Frame
  - ADAGE and IGEM report through 2050
  - NEMS reports through 2030
- Technology Detail
  - ADAGE and IGEM are top-down models with limited technology detail
  - NEMS is a bottom-up model with extensive technology detail
- Macroeconomic Effects
  - NEMS Macroeconomic Activity Module is based on the Global Insight Model of the U.S. Economy, which is a macroeconomic forecasting model.
    - Based on estimated relationships at an aggregate level, using adaptive rather than rational expectations.
    - Forecasts effects at the aggregate level, such as how GDP and unemployment, are affected by changes in inflation or fiscal and monetary policies.
    - These types of models can capture short- and medium-term disequilibrium adjustments in response to exogenous shocks. They can address short and medium-term transition costs of energy policies as the economy transitions to a long-run growth path. They have more detailed government sectors and a well-defined set of fiscal policies. In addition, they can incorporate accommodating monetary policies.
  - IGEM and ADAGE are Computable General Equilibrium models
    - Structural models based on microeconomic foundations.
    - They build up their representation of the whole economy through the interactions of multiple agents (e.g. households and firms), whose decisions are based upon optimization.
    - These models are best suited for capturing long-run equilibrium responses, and unique characteristics of specific sectors of the economy.

FMPA-POD1-00241

HEARING EXHIBIT - 00000404

Attachment POD-2.2 Analysis of EPA's CO2 Emission Allowance Price Projections

HEARING EXHIBIT - 00000406

FMPA-POD1-00242

Analysis of EPA's S.2191 CO2 Emission Allowance Price Projections

Analysis of S.2191

	EPA - ADAGE Model of "S.2191 Scenario 2" (2005 $/ton)	Five Year Average Annual Escalation Rate	EPA - IGEM Model of "S.2191 Scenario 2" (2005 $/ton)	Five Year Average Annual Escalation Rate	Values Used in Table 20-1 (Nominal $/ton)
2012	-	-	$34.57	-	**$40.54**
2013	-	-	$36.30	-	**$43.54**
2014	-	-	$38.10	-	**$46.76**
2015	$29.00	-	$40.00	-	**$50.21**
2016	$30.45	-	$41.99	-	**$53.93**
2017	$31.97	-	$44.08	-	**$57.91**
2018	$33.56	-	$46.28	-	**$62.19**
2019	$35.24	-	$48.58	-	**$66.79**
2020	$37.00	1.0499	$51.00	**1.0498**	**$71.73**
2021	$38.98	-	$53.54	-	**$77.03**
2022	$41.06	-	$56.20	-	**$82.72**
2023	$43.25	-	$58.99	-	**$88.83**
2024	$45.57	-	$61.92	-	**$95.39**
2025	$48.00	1.0534	$65.00	**1.0497**	**$102.43**
2026	$50.36	-	$68.26	-	**$110.04**
2027	$52.83	-	$71.68	-	**$118.21**
2028	$55.42	-	$75.27	-	-
2029	$58.14	-	$79.04	-	-
2030	$61.00	1.0491	$83.00	**1.0501**	-

8

FMPA's Response to Staff's Third Request for Production of Documents (Nos. 5-6, 8-10)

HEARING EXHIBIT - 00000407

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition to determine need for Cane Island Power Park Unit 4 electrical power plant in Osceola County, by Florida Municipal Power Agency.	DOCKET NO. 080253-EM DATED: July 2, 2008

RECEIVED
JUL 32 2008
FLORIDA PUBLIC SERVICE COMMISSION
OFFICE OF THE GENERAL COUNSEL

FLORIDA MUNICIPAL POWER AGENCY RESPONSES TO
STAFF'S THIRD REQUEST FOR PRODUCTION DOCUMENTS (NOS. 5-10)

Florida Municipal Power Agency (FMPA) pursuant to Rule 28-106.26, Florida Administrative Code, and Rule 1.350, Florida Rules of Civil Procedure, hereby responds to Staff's Third Request for Production of Documents (Nos. 5-10).

DOCUMENTS REQUESTED

5. **Regarding the financial and economic parameters assumed in the application, please provide complete copies of all source documents, reports, etc. that support the selection of the assumed escalation rates, the assumed long-term tax-exempt municipal bond interest rate, and the assumed present worth discount rates.**

Response to Request 5: Please see the attached memo on Blue Chip Economic Indicators, which was prepared for FMPA by R.W. Beck on October 22, 2007. The selection of the general inflation and escalation rates used consistently throughout the Cane Island 4 Need for Power Application (2.3 percent) was based on the Consumer Price Index (CPI) projections included in the previously referenced memo.

The selection of the long-term tax-exempt municipal bond rate (5.0 percent) was based on a consistent long-term tax-exempt municipal bond rate. As discussed in response to Staff's Interrogatory No. 22, for comparison purposes the 30 year tax-exempt municipal bond rate presented June 17, 2008 on Blomberg.com (www.bloomberg.com/markets/rates) for AAA rated, tax-exempt insured revenue bonds was 4.85 percent.

The 5.0 percent interest rate used in the Application does not include issuance fees, which were accounted separately in the Cane Island 4 Need for Power Application.

The present worth discount rate was assumed to be equal to the long-term tax-exempt municipal bond rate (5.0 percent). There are no specific source documents or reports that were relied upon in making this assumption.

6. **Please provide a complete copy of each FMPA member's most recent registration statement for the issuance of securities.**

Response to Request 6: Through discussions with counsel for the Commission, FMPA has confirmed that production of the attached official statement entitled *All-Requirements Power Supply Project Revenue Bonds, Series 2006B and Series 2006C,* dated March 24, 2006 will satisfactorily address the request made by Staff in Production of Documents Request No. 6. As a municipal utility, FMPA does not have registration statements.

8. **Please provide a copy of the most recent Moody's Investor Service's credit report and analysis for FMPA.**

Response to Request 8: Please refer to the attached Moody's Investor Services' rating of FMPA's revenue bonds, dated March 17, 2006.

9. **Please provide a copy of the most recent Fitch Rating's credit report and analysis for FMPA.**

Response to Request 9: Please refer to the attached Fitch Ratings' rating of FMPA's revenue bonds, dated March 8, 2006.

10. **Please refer to page 8, lines 2-5, of the direct testimony of Myron R. Rollins. Please provide complete copies of all source documents, reports, etc. that support the selection of 2.0 percent bond issuance fee, an assumed 0.50 percent annual property insurance cost, and a debt service reserve fund equal to 100 percent of the average annual debt service requirement earning interest at an interest rate equal to the bond interest rate.**

Response to Request 10: The 2.0 percent bond issuance fee, 0.50 percent annual property insurance cost, and debt service reserve fund (equal to 50 percent of the average annual debt service, or 6 months, not 100 percent as incorrectly stated in Witness Rollins' direct testimony) were selected as appropriate values that may be considered typical for financing projects similar to the proposed Cane Island 4 generating unit. There are no specific source documents or reports that were relied upon in selecting these parameters.

Respectfully submitted this 2nd day of July, 2008.

HOPPING GREEN & SAMS, P.A.

Gary V. Perko
Hopping Green & Sams, P.A.
123 S. Calhoun Street
Tallahassee, FL 32314
(850) 222-7500 (telephone)
(850) 224-8551 (facsimile)
Email: GPerko@hgslaw.com

Attorney for Florida Municipal Power Agency

MEMORANDUM

RW BECK

To: Distribution List

From: Richard Cuthbert

Subject: **Blue Chip Economic Indicator Projections**

Date: October 22, 2007

Attached is a summary of financial projections from the October 10, 2007 *Blue Chip Economic Indicators (BCEI)*. The attached sheet provides both short-term and long-term projections through the year 2018 for the gross domestic product (GDP) chained price index, the consumer price index (CPI), and average yields on 3-month Treasury bills and 10-year Treasury notes. Two graphs are included, which compare historical and projected changes in inflation and overall growth of the U.S. economy as measured by the CPI and the Real GDP Index (Chained). Changes in projections for these two indicators from prior *BCEI* publications are also shown.

Current forecasts indicate a higher level of projected inflation for 2007 than previously anticipated (now 2.7% for both the CPI and the GDP Price Index). The housing sector downturn continues to be of concern to economists as this may affect consumer spending and business investments. Long-term projections indicate lower inflationary levels in the following years despite these concerns. The projected average long-term rates of inflation reflect moderately low inflation levels at approximately 2.3% annually for the CPI and at 2.1% annually for the GDP Price Index for 2007 to 2018. In general the GDP Price Index should be used as a default for utility forecasting.

Interest rates for the 3-month Treasury bills are projected to decline from current levels to 4.2% while the 10-year Treasury notes are expected to remain at current levels through 2008. Long-term interest rate projections indicate slight decreases in the 3-month Treasury rates to approximately 4.5% and the 10-year Treasury rates to 5.1%. Overall current projections assume slightly lower economic growth than previously reported with real GDP averaging about 2.7% per year from 2007 through 2018.

This memorandum is updated twice each year, but monthly data is also available. For information, please contact Gina Baxter at (206) 695-4768. The firm also maintains on-line internet access to numerous data series and projections. Please feel free to contact me or one of the other economists in the firm if you need additional information.

RWC:
Attachments

Economic Projections (Summarized from "Blue Chip Economic Indicators")

SHORT-TERM PROJECTIONS: October 10, 2007

Blue Chip Consensus Annual Projections:

Percent Change Over Prior Year

	2007				2008			
	Average	6-months Ago	Top 10	Bottom 10	Average	6-months Ago	Top 10	Bottom 10
GDP Price Index	2.7	2.2	2.9	2.5	2.1	2.1	2.7	1.6
CPI	2.7	2.0	2.9	2.6	2.4	2.4	3.0	1.8

Average for Year

	2007				2008			
	Average	6-months Ago	Top 10	Bottom 10	Average	6-months Ago	Top 10	Bottom 10
Treasury Bills - 3-month	4.6	5.0	4.8	4.3	4.2	4.9	4.7	3.7
Treasury Notes - 10-year	4.7	4.8	4.8	4.6	4.8	5.0	5.2	4.5

Blue Chip Consensus Quarterly Projections:

		*% Change from Prior Quarter **		*Average Yield for Quarter **	
		GDP Price Index	CPI	3-month T-Bills	10-year T-Notes
2006	1st Quarter Actual	3.4	1.8	4.4	4.6
	2nd Quarter Actual	3.5	5.1	4.7	5.1
	3rd Quarter Actual	2.4	3.0	4.9	4.9
	4th Quarter Actual	1.7	-2.0	4.9	4.6
2007	1st Quarter Actual	4.2	3.8	5.0	4.7
	2nd Quarter Actual	2.6	6.0	4.7	4.9
	3rd Quarter Forecast	1.7	1.9	4.3	4.7
	4th Quarter Forecast	1.9	2.0	4.1	4.6
2008	1st Quarter Forecast	2.4	2.3	4.1	4.7
	2nd Quarter Forecast	2.1	2.3	4.1	4.7
	3rd Quarter Forecast	2.1	2.3	4.2	4.8
	4th Quarter Forecast	2.0	2.1	4.3	4.9

* Note - Figures represent annualized % change from prior quarter. Use quarterly information with care; estimates are subject to revisions, even "actuals".

LONG-TERM PROJECTIONS: October 10, 2007

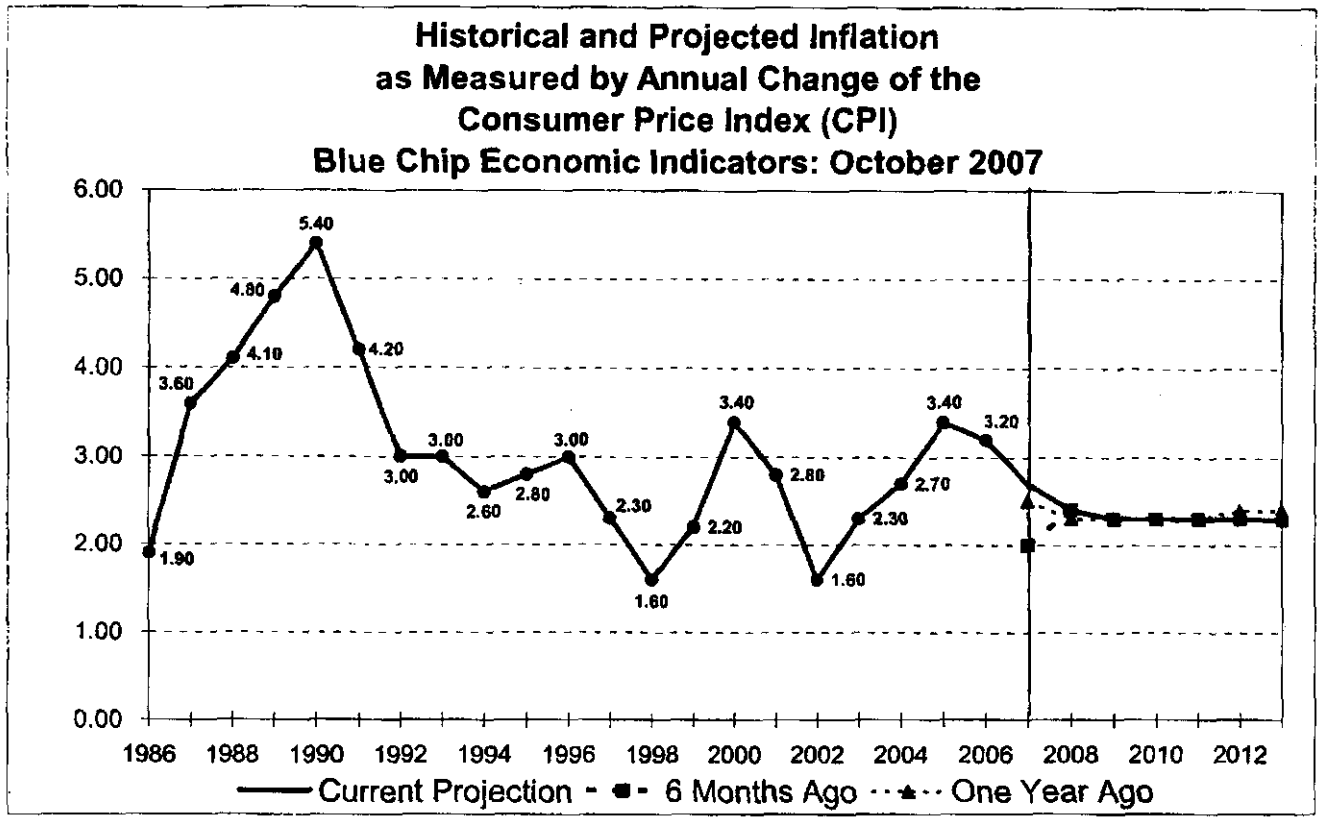
Percent Change from Prior Year's Annual Rate

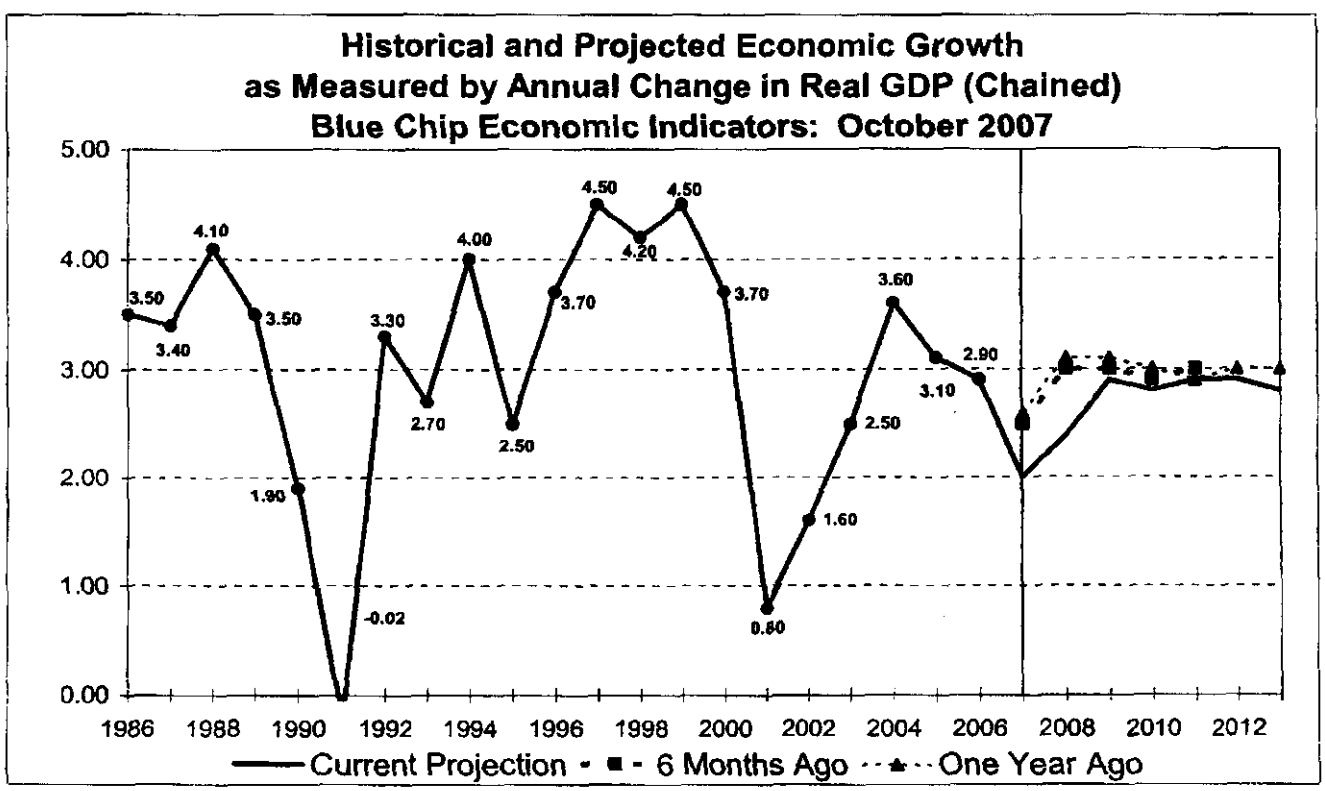
	2009	2010	2011	2012	2013	*Annual Rates* 2009 - 2013	2007 - 2018
GDP Price Index							
Blue Chip Consensus	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Consensus - Six Months Ago	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Top 10 Average	2.5	2.5	2.4	2.4	2.5	2.5	2.5
Bottom 10 Average	1.9	1.7	1.9	1.9	1.9	1.8	1.9
Consumer Price Index (CPI)							
Blue Chip Consensus	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Consensus - Six Months Ago	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Top 10 Average	2.7	2.7	2.7	2.6	2.6	2.6	2.7
Bottom 10 Average	1.8	1.8	1.9	1.9	1.9	1.9	1.9

Annual Average

	2009	2010	2011	2012	2013	2009 - 2013	2007 - 2018
Treasury Bills - 3-month							
Blue Chip Consensus	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Consensus - Six Months Ago	4.7	4.6	4.6	4.7	4.7	4.6	4.7
Top 10 Average	4.9	5.0	4.9	4.9	5.0	5.0	4.9
Bottom 10 Average	4.1	4.1	4.1	4.2	4.1	4.1	4.1
Treasury Notes - 10-Year							
Blue Chip Consensus	5.1	5.2	5.2	5.2	5.2	5.2	5.1
Consensus - Six Months Ago	5.2	5.1	5.2	5.2	5.3	5.2	5.2
Top 10 Average	5.4	5.6	5.6	5.6	5.7	5.6	5.5
Bottom 10 Average	4.8	4.9	4.8	4.8	4.8	4.8	4.7

HEARING EXHIBIT - 00000412


Historical and Projected Inflation
as Measured by Annual Change of the
Consumer Price Index (CPI)
Blue Chip Economic Indicators: October 2007
6.00
5.00
4.00
3.00
2.00
1.00
0.00
1986 1988 1990 1992 1994 1996 1998 2000 2002 2004 2006 2008 2010 2012
Current Projection
6 Months Ago
One Year Ago


Historical and Projected Economic Growth
as Measured by Annual Change in Real GDP (Chained)
Blue Chip Economic Indicators: October 2007
5.00
4.00
3.00
2.00
1.00
0.00
1986 1988 1990 1992 1994 1996 1998 2000 2002 2004 2006 2008 2010 2012
Current Projection
6 Months Ago
One Year Ago

NEW ISSUE—BOOK-ENTRY-ONLY

Ratings: *Moody's: Aaa (CIFG Insured)*
Fitch: AAA (CIFG Insured)
See "Credit Ratings" herein.

In the opinion of Bond Counsel, under existing law and assuming compliance with the tax covenants described herein, and the accuracy of certain representations and certifications made by FMPA as described herein, interest on the Series 2006B Bonds is excluded from gross income for Federal income tax purposes under Section 103 of the Internal Revenue Code of 1986, as amended (the "Code"). Bond Counsel is also of the opinion that such interest is not treated as a preference item in calculating the alternative minimum tax imposed under the Code with respect to individuals and corporations. Interest on the Series 2006B Bonds is, however, included in the adjusted current earnings of certain corporations for purposes of computing the alternative minimum tax imposed on such corporations. Interest on the Series 2006C Bonds is not excluded from gross income for Federal income tax purposes. Bond Counsel is further of the opinion that the Offered Securities and the interest thereon are exempt from taxation under existing laws of the State of Florida, except as to estate taxes and taxes imposed by Chapter 220, Florida Statutes, on interest, income or profits on debt obligations owned by corporations, banks and savings associations. See "TAX MATTERS" herein regarding certain other tax considerations.

$270,825,000
FLORIDA MUNICIPAL POWER AGENCY
All-Requirements Power Supply Project Revenue Bonds,
$225,825,000 Series 2006B (Auction Rate Securities)
$45,000,000 Taxable Series 2006C (Auction Rate Securities)

Dated: Date of Issuance **Due:** as shown on the inside front cover

The Series 2006B Bonds are being issued by the Florida Municipal Power Agency ("FMPA" or the "Agency") to provide a portion of the funds needed to (i) finance the acquisition and construction of the Treasure Coast Energy Center, (ii) finance certain obligations of FMPA relating to Public Gas Partners, (iii) refinance certain loans of FMPA related to the All-Requirements Project and (iv) pay the costs of issuance of the Series 2006B Bonds. The Series 2006C Bonds are being issued by FMPA to provide a portion of the funds needed to finance certain other obligations of FMPA related to Public Gas Partners Pool and pay the costs of issuance of the Series 2006C Bonds. The Series 2006B Bonds and Series 2006C Bonds together are referred to herein as the Offered Securities. The Offered Securities are payable and secured on a parity with FMPA's senior lien Bonds issued for the All-Requirements Power Supply Project (the "Project"), including those senior lien Bonds presently outstanding and those that may be issued for the Project in the future, including $125,020,000 of senior lien Bonds to be issued as fixed rate bonds simultaneously with the Offered Securities.

The Offered Securities are issuable as fully registered bonds and when issued will be registered in the name of Cede & Co., as Bondholder and Securities Depository Nominee of The Depository Trust Company, New York, New York. Individual purchases will be made in book-entry-only form through DTC Participants. Wachovia Bank, National Association, Jacksonville, Florida, is the Trustee, Paying Agent and Bond Registrar for the Offered Securities and all other parity senior lien Bonds.

The Offered Securities will accrue interest from the date of original issuance for the initial Dutch Auction Rate Periods at rates established by the Underwriters prior to the delivery of the Offered Securities. After the initial Dutch Auction Rate Period, the Offered Securities will accrue interest for each subsequent Dutch Auction Rate Period (initially, the Standard Auction Period is seven days for the Series 2006B-1 Bonds, Series 2006B-2 Bonds, Series 2006B-3 Bonds, Series 2006B-4 Bonds and Series 2006C Bonds) at the Dutch Auction Rate for such period determined pursuant to the Dutch Auction Procedures described in Appendix H hereto. Prospective purchasers of the Offered Securities should carefully review the Dutch Auction Procedures and should note that such procedures provide that (i) a Bid or Sell Order constitutes a commitment to purchase or sell Offered Securities based upon the results of an Auction, (ii) Auctions will be conducted through telephone communications and (iii) settlement for purchases and sales will be made on the Business Day following an Auction. Beneficial interests in the Offered Securities may be transferred only through a Broker-Dealer or pursuant to a Bid or Sell Order placed in an Auction. See "DESCRIPTION OF THE OFFERED SECURITIES—Special Considerations."

The Series 2006B Bonds while bearing interest at the Dutch Auction Rates are subject to sinking fund redemption prior to maturity as described herein. The Offered Securities while bearing interest at the Dutch Auction Rates are subject to optional redemption prior to maturity as described herein. The Offered Securities are also subject to mandatory tender for purchase upon conversion to another Interest Mode from the Dutch Auction Mode.

The Offered Securities are direct and special obligations of FMPA, payable out of the revenues and other funds of the Project pledged thereto under the Resolution. Neither the State of Florida nor any political subdivision thereof other than FMPA, nor any Member of FMPA, is obligated to pay the Offered Securities. Neither the full faith and credit nor the taxing power of the State of Florida or any political subdivision thereof or any Member is pledged to the payment of the Offered Securities. FMPA has no taxing power.

The scheduled payment of principal of and interest on the Offered Securities when due will be guaranteed under insurance policies to be issued concurrently with the delivery of the Offered Securities by CIFG ASSURANCE NORTH AMERICA, INC.

CIFG
IXIS FINANCIAL GUARANTY

The Offered Securities are offered when, as and if issued and received by the Underwriters, subject to the approval of legality by Nixon Peabody LLP, New York, New York, Bond Counsel. Certain legal matters in connection with the Offered Securities will be passed upon for the Underwriters by their counsel, Orrick, Herrington & Sutcliffe LLP, New York, New York. Certain legal matters in connection with the Offered Securities are subject to the approval of Frederick M. Bryant, Esquire, FMPA's General Counsel. Dunlap & Associates, Inc., Winter Park, Florida, is acting as FMPA's Financial Advisor. It is expected that the Offered Securities in book-entry-only form will be available for delivery through The Depository Trust Company in New York, New York on or about March 30, 2006.

A.G. Edwards
JPMorgan

Merrill Lynch & Co.
UBS Investment Bank

Dated: March 24, 2006

FMPA-POD3-00004

HEARING EXHIBIT - 00000414

Insert to Pages 8 and 9

to the

OFFICIAL STATEMENT

of the

FLORIDA MUNICIPAL POWER AGENCY

Relating to its

$270,825,000

ALL-REQUIREMENTS POWER SUPPLY PROJECT REVENUE BONDS,
$225,825,000 SERIES 2006B (AUCTION RATE SECURITIES)
$45,000,000 TAXABLE SERIES 2006C (AUCTION RATE SECURITIES)

Under the heading "DESCRIPTION OF THE OFFERED SECURITIES--Redemption Provisions--Mandatory Redemption," the mandatory redemption schedules for the Series 2006B-1 Bonds, Series 2006B-2 Bonds, Series 2006B-3 Bonds and Series 2006B-4 Bonds incorrectly contain two entries for the year 2018. In each case the second reference to 2018 should be to 2019.

HEARING EXHIBIT - 00000415

$225,825,000
ALL-REQUIREMENTS POWER SUPPLY PROJECT REVENUE BONDS, SERIES 2006B (AUCTION RATE SECURITIES)

$55,450,000 Series 2006B-1 Bonds	**Due: October 1, 2027**
$55,450,000 Series 2006B-2 Bonds	**Due: October 1, 2027**
$55,450,000 Series 2006B-3 Bonds	**Due: October 1, 2027**
$59,475,000 Series 2006B-4 Bonds	**Due: October 1, 2035**

Dated: Date of Issuance

Price: 100%

Series 2006B-1

Auction Periods:	First Auction Date:	First Interest Payment Date:	Initial CUSIP No[(1)].:
Seven-day	April 10, 2006	April 11, 2006	342816 UG8

Series 2006B-2

Auction Periods:	First Auction Date:	First Interest Payment Date:	Initial CUSIP No[(1)].:
Seven-day	April 10, 2006	April 11, 2006	342816 UH6

Series 2006B-3

Auction Periods:	First Auction Date:	First Interest Payment Date:	Initial CUSIP No[(1)].:
Seven-day	April 12, 2006	April 13, 2006	342816 UJ2

Series 2006B-4

Auction Periods:	First Auction Date:	First Interest Payment Date:	Initial CUSIP No[(1)].:
Seven-day	April 7, 2006	April 10, 2006	342816 UK9

$45,000,000
ALL-REQUIREMENTS POWER SUPPLY PROJECT REVENUE BONDS, SERIES 2006C (AUCTION RATE SECURITIES)

Dated: Date of Issuance **Price: 100%** **Due: October 1, 2025**

Auction Periods:	First Auction Date:	First Interest Payment Date:	Initial CUSIP No[(1)].:
Seven-day	April 13, 2006	April 14, 2006	342816 UL7

(1) CUSIP numbers have been assigned by an organization not affiliated with FMPA and are included solely for the convenience of the holders of the Offered Securities. FMPA is not responsible for the selection or uses of these CUSIP numbers, nor is any representation made as to their correctness on the Offered Securities or as indicated above.

FLORIDA MUNICIPAL POWER AGENCY

8553 Commodity Circle
Orlando, Florida 32819
(407) 355-7767
Telecopy: (407) 355-5793

OFFICERS OF THE BOARD
and
OFFICERS OF THE EXECUTIVE COMMITTEE

Elie J. Boudreaux III, Chairman
Vicente R. Ruano, Vice Chairman
Susan Freiden, Secretary
James C. Welsh, Treasurer

PARTICIPANTS IN THE PROJECT

City of Bushnell
City of Clewiston
City of Fort Meade
Fort Pierce Utilities Authority
City of Green Cove Springs
Town of Havana
City of Jacksonville Beach
Utility Board of the City of Key West
Kissimmee Utility Authority
City of Lake Worth
City of Leesburg
City of Newberry
City of Ocala
City of Starke
City of Vero Beach

MANAGEMENT

Roger A. Fontes, General Manager and CEO
Frederick M. Bryant, Esquire, General Counsel
Richard L. Casey, Assistant General Manager, Power Resources
Mark J. Larson, CPA, Assistant General Manager, CFO and Risk Manager
Thomas E. Reedy, P.E., Assistant General Manager, Member and Administrative Services

FINANCIAL ADVISOR
Dunlap & Associates, Inc.
Winter Park, Florida

BOND COUNSEL
Nixon Peabody LLP
New York, New York

TRUSTEE
Wachovia Bank, National Association
Jacksonville, Florida

INDEPENDENT ACCOUNTANTS
Purvis Gray & Company
Ocala, Florida

FMPA-POD3-00007

HEARING EXHIBIT - 00000417

No dealer or any other person has been authorized to give any information or to make any representation, other than the information and representations contained herein, in connection with the offering of the Offered Securities and, if given or made, such information or representations must not be relied upon. This Official Statement does not constitute an offer to sell or a solicitation of an offer to buy, nor shall there be any sale of the Offered Securities, to any person in any jurisdiction to whom it is unlawful to make such solicitation, offer or sale. The information and expressions of opinion herein are subject to change without notice, and neither the delivery of this Official Statement nor any sale made hereunder shall create, under any circumstances, any implication that there has been no change in the affairs of the Insurer, FMPA or the Participants since the date hereof.

The information in this Official Statement has been furnished by FMPA, the Participants and the Insurer and includes information obtained from other sources, all of which are believed to be reliable. The purpose of this Official Statement is to provide information to prospective investors in the Offered Securities and is not to be used for any other purpose or relied on by any other person.

This Official Statement contains statements which, to the extent they are not recitations of historical fact, constitute "forward-looking statements." In this respect, the words "estimate", "project", "anticipate", "expect", "intend", "believe" and similar expressions are intended to identify forward-looking statements. A number of factors affecting FMPA's, the Participants' and the Insurer's business and financial results could cause actual results to differ materially from those stated in the forward-looking statements.

IN CONNECTION WITH THE OFFERING OF THE OFFERED SECURITIES, THE UNDERWRITERS MAY OVERALLOT OR EFFECT TRANSACTIONS THAT STABILIZE OR MAINTAIN THE MARKET PRICES OF SUCH OFFERED SECURITIES AT A LEVEL ABOVE THAT WHICH MIGHT OTHERWISE PREVAIL IN THE OPEN MARKET. SUCH STABILIZING, IF COMMENCED, MAY BE DISCONTINUED AT ANY TIME.

THE OFFERED SECURITIES HAVE NOT BEEN REGISTERED UNDER THE SECURITIES ACT OF 1933 NOR HAS THE RESOLUTION BEEN QUALIFIED UNDER THE TRUST INDENTURE ACT OF 1939 IN RELIANCE UPON EXEMPTIONS CONTAINED IN SUCH ACTS.

Certain materials filed with the Nationally Recognized Municipal Securities Information Repositories (each, a "NRMSIR") are included herein by reference. While such information is also available on FMPA's website, only the materials filed with the NRMSIRs are included by reference herein. Information appearing on FMPA's website and not otherwise appearing or included by reference from materials filed with the NRMSIRs herein is not a part of this Official Statement. See "FMPA FINANCIAL STATEMENTS" herein.

The Underwriters have provided the following sentence for inclusion in this Official Statement: The Underwriters have reviewed the information in this Official Statement in accordance with, and as part of, their responsibilities to investors under the federal securities laws as applied to the facts and circumstances of this transaction, but the Underwriters do not guarantee the accuracy or completeness of such information.

Other than with respect to information concerning CIFG Assurance North America, Inc. ("CIFG") contained under the caption "Bond Insurance—CIFG Assurance North America, Inc." "—General" "—Capitalization" and APPENDIX G - "FORM OF BOND INSURANCE POLICY" herein, none of the information in this Official Statement has been supplied or verified by CIFG and CIFG makes no representation or warranty, express or implied, as to (i) the accuracy or completeness of such information; (ii) the validity of the Offered Securities; or (iii) the tax exempt status of the interest on the Offered Securities.

FMPA-POD3-00008

HEARING EXHIBIT - 00000418

TABLE OF CONTENTS

Page

FLORIDA MUNICIPAL POWER AGENCY i
INTRODUCTION 1
Florida Municipal Power Agency 1
The Project 1
Authority for the Offered Securities 2
Purpose of the Offered Securities 2
Outstanding Indebtedness 2
Trustee 3
Payments under the Power Supply Contracts 3
Security for the Offered Securities 3
Possible Consolidation of Other Projects into the Project and Addition of Participants to the Project 3
Additional Bonds 4
Subordinated Indebtedness 4
Major Participants 4
Bond Insurance 4
DESCRIPTION OF THE OFFERED SECURITIES 4
General Description 4
Auction Agent 6
Orders of Existing Owners and Potential Owners 6
Change of Dutch Auction Period 6
Special Considerations 6
Redemption Provisions 8
PLAN OF FINANCE 10
ESTIMATED SOURCES AND USES OF FUNDS 11
DEBT SERVICE REQUIREMENTS 12
RISK MANAGEMENT 13
General 13
Natural Gas Supply 13
Rate Setting 13
Interest Rate Swaps 13
SECURITY AND SOURCES OF PAYMENT FOR THE OFFERED SECURITIES 16
Pledge under the Resolution 16
Rates 17
All-Requirements Power Supply Contracts 17
Additional Bonds 17
Possible Consolidation of Other Projects Into the Project and Addition of Participants to the Project 17
Flow of Funds Under the Resolution 18
Debt Service Reserve 18
THE POWER SUPPLY CONTRACTS 18
Introduction 18
Purchase and Sale 19
Early Termination of a Power Supply Contract 19
Contract Rate of Delivery 19
Payments under Power Supply Contracts 20
BOND INSURANCE 20
General 20
CIFG Assurance North America, Inc. 21
General 21
Capitalization 21
FLORIDA MUNICIPAL POWER AGENCY 22
General 22
Organization and Management 22
THE PROJECT 25
Introduction 25
Project Generating Facilities Owned by FMPA 25
Purchased Power and Other Contracts 27
Member Contributed Resources 27
Future Power Supply 28
Fuel Supply 28
Transmission and Dispatch Agreements 29
Florida Municipal Power Pool 30
Future Capital Requirements 30
Project Operations 30
Historical and Estimated Future Capacity Requirements and Resources 31

Page

HISTORICAL OPERATING RESULTS FOR THE PROJECT 33
THE PROJECT PARTICIPANTS 34
Description of the Participants 34
Change in Status of Certain Participants 34
Major Participants' Historical Net Energy Requirements and Peak Demand 35
Major Participants 35
OTHER FMPA PROJECTS 35
Introduction 35
Stanton Project 36
Stanton II Project 37
St. Lucie Project 37
Tri-City Project 38
Future Power Supply and Operations 39
Pooled Loan Project 39
STATE REGULATION 39
COMPETITIVE POSITION OF FMPA AND THE PARTICIPANTS 40
General 40
FMPA's Competitive Position 40
Expected Effects of Retail Competition 40
Competitive Position of FMPA's Members 41
CERTAIN FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY 41
General 41
Energy Policy Act of 1992 41
FERC Transmission Initiatives 42
2005 Energy Policy Act 42
Environmental 43
UNDERWRITING 44
FINANCIAL ADVISOR 44
LITIGATION 44
ENFORCEABILITY OF REMEDIES 44
CREDIT RATINGS 45
Offered Securities 45
General 45
TAX MATTERS 45
Federal Income Taxes–Series 2006B Bonds 45
Federal Income Taxes – Series 2006C Bonds (Taxable Auction Rate Securities) 46
State Taxes 47
APPROVAL OF LEGAL PROCEEDINGS 47
RELATIONSHIPS AMONG PARTIES 48
VALIDATION 48
FMPA FINANCIAL STATEMENTS 48
ADDITIONAL FMPA INFORMATION; CONTINUING DISCLOSURE 48
DISCLOSURE REQUIRED BY FLORIDA BLUE SKY REGULATIONS 49
MISCELLANEOUS 49
APPENDIX A — MEMBERS' PARTICIPATION IN FMPA PROJECTS A-1
APPENDIX B — THE MAJOR PARTICIPANTS B-1
APPENDIX C — SUMMARY OF CERTAIN PROVISIONS OF THE RESOLUTION AND POWER SUPPLY CONTRACTS C-1
APPENDIX D — PROPOSED FORM OF OPINIONS OF BOND COUNSEL D-1
APPENDIX E — BOOK-ENTRY-ONLY SYSTEM E-1
APPENDIX F — CONTINUING DISCLOSURE UNDER SEC RULE 15C2-12 ..... F-1
APPENDIX G — FORM OF BOND INSURANCE POLICY G-1
APPENDIX H —DUTCH AUCTION PROCEDURES H-1

FMPA-POD3-00009

HEARING EXHIBIT - 00000419

[This Page Intentionally Left Blank]

HEARING EXHIBIT - 00000420

OFFICIAL STATEMENT
of the

FLORIDA MUNICIPAL POWER AGENCY

Relating to its

$270,825,000

ALL-REQUIREMENTS POWER SUPPLY PROJECT REVENUE BONDS,
$225,825,000 SERIES 2006B (AUCTION RATE SECURITIES)
$45,000,000 TAXABLE SERIES 2006C (AUCTION RATE SECURITIES)

INTRODUCTION

The purpose of this Official Statement (which includes the cover page and appendices and the information incorporated in this Official Statement by reference) of the Florida Municipal Power Agency ("FMPA" or the "Agency") is to set forth information concerning FMPA and its $225,825,000 principal amount of All-Requirements Power Supply Project Revenue Bonds, Series 2006B Bonds (Auction Rate Securities) consisting of $55,450,000 Series 2006B-1 Bonds, $55,450,000 Series 2006B-2 Bonds, $55,450,000 Series 2006B-3 Bonds and $59,475,000 Series 2006B-4 Bonds, (the "Series 2006B-1 Bonds," "Series 2006B-2 Bonds," "Series 2006B-3 Bonds" and "Series 2006B-4 Bonds," respectively, and collectively, the "Series 2006B Bonds") and $45,000,000 principal amount of All-Requirements Power Supply Project Revenue Bonds, Taxable Series 2006C Bonds (the "Series 2006C Bonds," and together with the Series 2006B Bonds, the "Offered Securities").

This Introduction contains a summary of certain of the information contained in this Official Statement. In order to make an informed decision as to whether to invest in the Offered Securities, a potential investor must read this Official Statement in its entirety.

Capitalized terms not otherwise defined in this Official Statement shall have the meanings set forth in the Appendices to this Official Statement.

Florida Municipal Power Agency

FMPA is a governmental legal entity, organized and existing under (i) Section 163.01 of the Florida Statutes (the "Florida Interlocal Cooperation Act"), (ii) Chapter 361, Part II of the Florida Statutes (the "Joint Powers Act"), and (iii) an interlocal agreement creating FMPA among the 29 members of FMPA (each individually a "Member" and collectively, the "Members") executed pursuant to the foregoing statutory authority (the "Interlocal Agreement"). The Members of FMPA are 29 Florida city commissions, city and town councils, utility commissions or utility authorities. Under Florida law, FMPA has authority to undertake and finance specified projects and, among other things, to plan, finance, acquire, construct, reconstruct, own, lease, operate, maintain, repair, improve, extend or otherwise participate jointly in those projects. FMPA has the authority to issue bonds or bond anticipation notes for the purpose of financing or refinancing the costs of these projects. See "FLORIDA MUNICIPAL POWER AGENCY."

The Project

The All-Requirements Power Supply Project (the "Project") is a power supply project under which FMPA provides to each of the participants (the "Participants") in the Project their individual "All-Requirements Service." For a particular Participant, its All-Requirements Service is all of the electric power and energy, transmission and associated services except for certain excluded resources. See "THE PROJECT PARTICIPANTS—Change in Status of Certain Participants." A Participant purchases its All-Requirements Service pursuant to an All-Requirements Power Supply Project Contract with FMPA (the "Power Supply Contracts"). See "THE POWER SUPPLY CONTRACTS."

The power supply assets of the Project include (i) undivided interests in generating facilities that are owned by FMPA; (ii) power supply resources under long- and short-term contracts to FMPA; (iii) generation assets owned

HEARING EXHIBIT - 00000421

by some of the Participants or in which some Participants have entitlement shares, the capacity and energy of which are sold to the Project; and (iv) transmission arrangements. For further description of the Project, see "THE PROJECT."

Authority for the Offered Securities

The Offered Securities are being issued pursuant to the Florida Interlocal Cooperation Act, the Joint Powers Act and Chapter 166, Part II, Florida Statutes, (collectively, the "Act"), and the All-Requirements Power Supply Project Revenue Bond Resolution, adopted on March 22, 1985, as amended and restated in its entirety on May 23, 2003, as amended and supplemented, including as supplemented by the Multiple Series Supplemental All-Requirements Power Supply Project Revenue Bond Resolution as amended by the Amendment No. 1 to Multiple Series Supplemental All-Requirements Power Supply Project Revenue Bond Resolution each adopted on November 2, 2005 and as further amended by the Amendment No. 2 to Multiple Series Supplemental All-Requirements Power Supply Project Revenue Bond Resolution adopted on February 23, 2006 (collectively, the "Resolution").

Purpose of the Offered Securities

The proceeds of the Series 2006B Bonds, together with the proceeds of $125,020,000 of FMPA's All-Requirements Power Supply Project Revenue Bonds, Series 2006A (the "Series 2006A Bonds"), expected to be issued simultaneously with the Offered Securities, will be used to provide a portion of the funds needed to (i) finance the acquisition and construction of a 300 MW combined cycle unit natural gas plant (the "Treasure Coast Energy Center"), (ii) finance certain obligations of FMPA relating to Public Gas Partners, (iii) partially refinance certain loans of FMPA related to the Project and (iv) pay the costs of issuance of the Series 2006A Bonds and Series 2006B Bonds. See "PLAN OF FINANCE."

The proceeds of the Series 2006C Bonds will be used to finance certain other obligations of FMPA related to Public Gas Partners Pool and pay the costs of issuance of the Series 2006C Bonds. See "PLAN OF FINANCE."

Outstanding Indebtedness

Upon issuance of the Offered Securities and the Series 2006A Bonds, FMPA will have outstanding the following Bonds related to the All-Requirements Project: the Offered Securities, the Series 2006A Bonds, $52,535,000 Series 2003A Bonds (the "Series 2003A Bonds"), $35,750,000 Series 2003B-1 Bonds (the "Series 2003B-1 Bonds"), $54,900,000 Series 2003B-2 Bonds (the "Series 2003B-2 Bonds," and together with the Series 2003B-1 Bonds, the "Series 2003B Bonds"), $20,125,000 Series 2000 Bonds (the "Series 2000 Bonds"), $30,000,000 Series 2000-1 (the "Series 2000-1 Bonds") and $40,000,000 Series 2000-2 Bonds (the "Series 2000-2 Bonds").

The Offered Securities, the Series 2006A Bonds, the Series 2003A Bonds, the Series 2003B Bonds, the Series 2000 Bonds, the Series 2000-1 Bonds and the Series 2000-2 Bonds will be parity senior lien bonds and, together with all additional senior lien bonds on a parity therewith issued in the future (the "Additional Bonds"), are called the "Bonds."

FMPA has ten loans on behalf of the Project from FMPA's Pooled Loan Project (the "Pooled Loan Obligations") with an aggregate outstanding principal amount of $129,970,000. Proceeds of three of the loans, in the aggregate principal amount of approximately $40,059,000, is financing the development costs of the Treasure Coast Energy Center. The proceeds of two of the loans, in the aggregate principal amount of approximately $58,000,000, financed certain other Project related activities, including the design and construction of Stock Island Unit 4 combustion turbine currently under construction at the Stock Island Plant near Key West and the acquisition of the 3,300-acre Taylor Energy Center site in Taylor County, Florida. The proceeds of the remaining five loans financed a portion of various facilities that have been completed. See "THE PROJECT—Future Power Supply." FMPA anticipates that the Pooled Loan Obligations will be retired with the proceeds of the Series 2006B Bonds and the Series 2006A Bonds.

FMPA-POD3-00012

HEARING EXHIBIT - 00000422

FMPA maintains a $100 million line of credit with Wachovia Bank, National Association ("Wachovia") for the Project's natural gas supply management program and other purposes. Drawings under the line of credit are subject to certain limitations. See "RISK MANAGEMENT." FMPA also has two taxable loans with Wachovia in the amount of $5,718,000 and $1,200,000.

Trustee

Wachovia is the Trustee under the Resolution for all debt issued under the Resolution, including all Bonds. Wachovia Corporation has entered into a definitive agreement to sell its corporate trust and structured finance trust services businesses to U.S. Bank National Association, this transaction closed on December 30, 2005. The Wachovia affiliate named as fiduciary or agent, as applicable, under each client agreement will continue in that role until U.S. Bank succeeds to that role in accordance with the terms of the governing instrument or agreement and applicable law. The date of such succession for the Offered Securities has not yet been determined.

Payments under the Power Supply Contracts

The Power Supply Contracts provide for payments by the Participants of amounts sufficient to pay debt service on all Bonds, including the Offered Securities, and Subordinated Debt and all other payments required by the Resolution, such as operation and maintenance costs of the Project and deposits to reserves. See "THE POWER SUPPLY CONTRACTS."

Security for the Offered Securities

The Offered Securities are direct and special obligations of FMPA payable solely from and secured solely by a pledge and assignment of (i) the proceeds of the sale of the Offered Securities, (ii) all right, title and interest of FMPA in, to and under the Power Supply Contracts, (iii) the Revenues (as defined in the Resolution), and (iv) all funds established by the Resolution including the investment income, if any, thereof, subject only to the provisions of the Resolution permitting the application thereof for the purposes and on the terms and conditions set forth in the Resolution.

FMPA has covenanted in the Resolution to fix, charge and collect rates and charges for the sale of the output of the Project to generate revenues in each year in an amount (with other available funds of FMPA) sufficient to pay all of FMPA's costs and expenses of the Project for that year, including Project operation and maintenance costs and all debt service on all Bonds and Subordinated Debt for that year.

Each Participant has agreed in its Power Supply Contract to fix, charge and collect rates and charges for the services of its electric or integrated utility system in each year sufficient to pay costs and expenses of its utility system for that year, including all amounts payable to FMPA under its Power Supply Contract for that year.

There is no Debt Service Reserve Requirement for the Offered Securities.

See "SECURITY AND SOURCES OF PAYMENT FOR THE OFFERED SECURITIES."

Possible Consolidation of Other Projects into the Project and Addition of Participants to the Project

The bond resolutions for certain other FMPA projects provide that under certain circumstances FMPA could issue Additional Bonds in exchange for the outstanding bonds for such projects and consolidate them with the Project. Such a consolidation could result in the addition of new Participants, the addition of new power resources to the Project and the incurrence of Additional Bonds. In order for such a consolidation to occur, FMPA would have to meet the test for the Additional Bonds to be issued under the Resolution. FMPA cannot predict the likelihood or timing of any such consolidation.

HEARING EXHIBIT - 00000423

Additional Bonds

FMPA may, upon compliance with certain terms and conditions set forth in the Resolution, issue additional parity senior lien bonds ("Additional Bonds") in an unlimited amount for the purpose of providing additional funds to finance costs incurred by FMPA in connection with the Project, including developmental costs, costs of acquisition and construction of additional power supply resources, operating costs and retirement costs. See "THE PROJECT – Future Capital Requirements" for a discussion of future additional power supply resources. The Resolution also authorizes the issuance of Additional Bonds to refund outstanding Bonds under the conditions specified in the Resolution.

Subordinated Indebtedness

The Resolution authorizes FMPA to incur subordinated indebtedness ("Subordinated Debt") in an unlimited amount for any lawful purpose of FMPA related to the Project. All Subordinated Debt will be subordinate as to security and source of payment to the Bonds, including all Additional Bonds.

Major Participants

Attached hereto as Appendix B is certain information for the following five Participants - Jacksonville Beach, Key West, Kissimmee Utilities Authority ("KUA"), Ocala and Vero Beach - each of which provided, to FMPA at least 9% of the revenues from the Project as of September 30, 2005. These five Participants are referred to in this Official Statement as the "Major Participants." The aggregate payments to FMPA by the Major Participants with respect to the Project as of September 30, 2005 was approximately 72% of all revenues of the Project. See "PROJECT PARTICIPANTS."

Bond Insurance

CIFG Assurance North America, Inc. (the "Insurer" or "CIFG") will issue a financial guaranty insurance policy with respect to each of the Series 2006B Bonds and the Series 2006C Bonds (each a "Policy" and together, the "Policies") guaranteeing the scheduled payment of the principal and interest on the Offered Securities. See "BOND INSURANCE."

DESCRIPTION OF THE OFFERED SECURITIES

The following is a summary of certain provisions of the Offered Securities. Reference is made to the Offered Securities themselves for the complete text thereof and to the Resolution, and the discussion herein is qualified by such references.

Each Series of the Offered Securities will initially bear interest at a Dutch Auction Rate but may be converted at the option of FMPA, subject to certain restrictions, to Offered Securities which bear interest at different rates including a Daily Rate, Weekly Rate, Flexible Rate or Fixed Rate. On the date of any such conversion, the Offered Securities will be subject to mandatory tender at a purchase price equal to 100% of the principal amount thereof, plus accrued interest; provided, however, that in the event of a failed conversion, the Offered Securities will not be subject to mandatory tender, will be returned to their owners, will automatically be converted to a Standard Auction Period and will bear interest at the Maximum Dutch Auction Rate for such Auction Period. The following description applies separately to each Series of the Offered Securities.

The following description applies to Series 2006B Bonds and Series 2006C Bonds while bearing interest at Dutch Auction Rates only.

General Description

The Offered Securities will be dated their date of issuance and will be initially in a Standard Auction Period of seven days in the case of the Series 2006B-1 Bonds, Series 2006B-2 Bonds, Series 2006B-3 Bonds, Series 2006B-4 Bonds and Series 2006C Bonds, subject to conversion in whole only to another Auction Period or in whole or in part to another Interest Mode as FMPA shall determine. The Series 2006B-1 Bonds, Series 2006B-2 Bonds

FMPA-POD3-00014

HEARING EXHIBIT - 00000424

and Series 2006B-3 Bonds will mature on October 1, 2027, the Series 2006B-4 Bonds will mature on October 1, 2035 and the Series 2006C Bonds will mature on October 1, 2025. The Series 2006B Bonds and Series 2006C Bonds are issuable only as fully registered bonds in authorized denominations of $25,000 or any integral multiple of $5,000 in excess thereof while in a Dutch Auction Mode. The Offered Securities will be registered in the name of Cede & Co., as Bondholder and Securities Depository Nominee of The Depository Trust Company, New York, New York. Individual purchases will be made in book-entry form only through DTC Participants. So long as the Offered Securities are registered in the name of Cede & Co., principal of, and interest on, the Offered Securities will be paid to Cede & Co. as the registered owner. See APPENDIX E-"BOOK-ENTRY-ONLY SYSTEM."

Interest on the Offered Securities in a Dutch Auction Mode will be computed on the basis of a 360-day year for the actual number of days elapsed.

The initial Dutch Auction Rate for each of the Offered Securities for the period from the date of issuance of the Offered Securities through the first Auction Date for such Series will be determined by the Underwriters, prior to delivery of the Offered Securities. During any Dutch Auction Rate Period, the Offered Securities will bear interest at the applicable Dutch Auction Rate. Except as otherwise provided in the Resolution, the "Dutch Auction Rate" will be the rate of interest per annum that results from implementation of the Dutch Auction Procedures as set forth in APPENDIX H; provided that such interest rate will not exceed the Maximum Dutch Auction Rate.

The Dutch Auction Rate for the next succeeding Auction Period will be determined as follows:

(A) if Sufficient Clearing Bids exist, then the Dutch Auction Rate for the next succeeding Auction Period therefor will be equal to the Winning Bid Rate so determined;

(B) if Sufficient Clearing Bids do not exist (other than because all of the Offered Securities are the subject of Submitted Hold Orders), then the Dutch Auction Rate for the next succeeding Auction Period therefor will be equal to the Maximum Dutch Auction Rate; and

(C) if all of the Offered Securities are subject to Submitted Hold Orders, then the Dutch Auction Rate for the next succeeding Auction Period therefor will be equal to the All Hold Rate.

Determination of the Dutch Auction Rate pursuant to the Dutch Auction Procedures shall be suspended upon the occurrence of an Event of Default consisting of the failure to pay principal or interest on the Offered Securities. Upon the occurrence of such an Event of Default on any Auction Date, no Auction will be held and the Dutch Auction Rate shall be equal to the Overdue Rate as determined on and as of the immediately preceding Auction Date for each Auction Period, commencing after the occurrence of such Event of Default.

Except as described above, in the event the Auction Agent shall fail to calculate or, for any reason, fails to provide the Auction Rate for any Auction Period, (i) if the preceding Auction Period was a period of 35 days or less, the new Auction Period shall be the same as the preceding Auction Period and the Dutch Auction Rate for the new Auction Period shall be the same as the Dutch Auction Rate for the preceding Auction Period, and (ii) if the preceding Auction Period was a period of greater than 35 days, the preceding Auction Period shall be extended to the next seventh day following the day that would have been the last day of such Auction Period had it not been extended (or if such seventh day is not followed by a Business Day then to the next succeeding day which is followed by a Business Day) and the Dutch Auction Rate in effect for the preceding Auction Period will continue in effect for the Auction Period as so extended. In the event the Auction Period is extended as set forth in clause (ii) of the preceding sentence, an Auction shall be held on the last Business Day of the Auction Period as so extended to take effect for an Auction Period beginning on the Business Day immediately following the last day of the Auction Period as extended which Auction Period will end on the date it would otherwise have ended on had the prior Auction Period not been extended.

"Auction Date" means for each Series of the Series 2006B Bonds and Series 2006C Bonds the first auction date set forth on the inside front cover page of this Official Statement for such series, and with respect to (i) the Series 2006B-1 Bonds and Series 2006B-2 Bonds for each Auction Period thereafter the last Monday of the immediately preceding Auction Period or, if such last Monday is not a Business Day, the next preceding Business

HEARING EXHIBIT - 00000425

Day; (ii) the Series 2006B-3 Bonds for each Auction Period thereafter the last Wednesday of the immediately preceding Auction Period or, if such last Wednesday is not a Business Day, the next preceding Business Day; (iii) the Series 2006B-4 Bonds for each Auction Period thereafter the last Friday of the immediately preceding Auction Period or, if such last Friday is not a Business Day, the next preceding Business Day; and (iv) the Series 2006C Bonds for each Auction Period thereafter the last Thursday of the immediately preceding Auction Period or, if such last Thursday is not a Business Day, the next preceding Business Day.

"Auction Period" means, during a Dutch Auction Rate Period, each period from and including the dated date of the Offered Securities to and including April 10, 2006 in the case of the Series 2006B-1 Bonds and Series 2006B-2 Bonds, April 12, 2006 in the case of the Series 2006B-3 Bonds, April 9, 2006 in the case of the Series 2006B-4 Bonds and April 13, 2006 in the case of the Series 2006C Bonds and, thereafter, for each Series of the Series 2006B Bonds and Series 2006C Bonds from and including the last Interest Payment Date for the immediately preceding Auction Period, to and including the earliest of (i) October 1, 2027, in the case of the Series 2006B-1 Bonds, Series 2006B-2 Bonds and Series 2006B-3 Bonds, October 1, 2035, in the case of the Series 2006B-4 Bonds and October 1, 2025, in the case of the Series 2006C Bonds, (ii) the day next preceding the last Interest Payment Date in respect of each Auction Period and (iii) the last day of such Dutch Auction Rate Period.

"Interest Payment Date" means the dates shown for each Series on the inside front cover page of this Official Statement as the first interest payment dates and, as to any Offered Security in a Dutch Auction Mode, (1) for an Auction Period of 91 days or less, the Business Day immediately succeeding the last day of such Auction Period and (2) for an Auction Period of more than 91 days, each 13th Tuesday in the case of the Series 2006B-1 Bonds and Series 2006B-2 Bonds, each 13th Thursday in the case of the Series 2006B-3 Bonds, each 13th Monday in the case of the Series 2006B-4 Bonds and each 13th Friday in the case of the Series 2006C Bonds (or if such day is not a Business Day, the next succeeding Business Day) after the first day of such Auction Period and the Business Day immediately succeeding the last day of such Auction Period.

Auction Agent

The Agency will enter into the Auction Agreement initially with Deutsche Bank Trust Company Americas, pursuant to which Deutsche Bank Trust Company Americas, as Agent for the Agency, will perform the duties of Auction Agent. The Auction Agreement will provide, among other things, that the Auction Agent will determine the Auction Rate for each Auction in accordance with the Auction Procedures.

Orders of Existing Owners and Potential Owners

The procedure for submitting orders prior to the Submission Deadline on each Auction Date is described in APPENDIX H, as are the particulars with regard to the determination of the Auction Rate and the allocation of Offered Securities bearing interest at Dutch Auction Rates.

Change of Dutch Auction Period

FMPA may change the length of an Auction Period or Standard Auction Period for any Series of the Offered Securities. The length of an Auction Period or the standard Auction Period may not be changed pursuant to the Resolution unless sufficient Clearing Bids existed at both the Auction immediately preceding the date the notice of such change was given and the Auction immediately preceding such changed Auction Period.

Special Considerations

Broker-Dealer May Bid for Its Own Account. A.G. Edwards & Sons, Inc., J.P. Morgan Securities Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated and UBS Securities LLC has each been appointed to serve as a Broker-Dealer (the "Initial Broker-Dealers"). Each Broker-Dealer is permitted to submit Orders in an auction for its own account. The Initial Broker-Dealers routinely place one or more orders in auctions generally for which they serve as broker-dealers, even after obtaining knowledge of some or all of the other orders, and they may do so with respect to the Offered Securities. If an Initial Broker-Dealer submits an Order in an Auction for Offered Securities for its own account, it is likely to have an advantage over other Bidders because it would have knowledge of all

FMPA-POD3-00016

HEARING EXHIBIT - 00000426

Orders placed through it in the Auction, and thus could determine the rate and size of its Order so as to ensure that its Order is likely to be accepted in the Auction and the Auction is likely to clear at a particular rate. Each of the Initial Broker-Dealers also routinely places one or more bids in auctions generally to prevent a failed auction or a clearing rate it believes is not a market rate. While they may do so with respect to the Offered Securities, they are not obligated to do so and may elect not to do so. Each of the Initial Broker-Dealers routinely encourages bidding by others in auctions generally to prevent a failed auction or a winning bid rate which they believe is not a market rate. By submitting Orders for its own account or encouraging other Bidders to submit Orders in an Auction, an Initial Broker-Dealer may cause some Bidders' Orders to be rejected in the Auction and may cause the Auction to clear at an interest rate that is lower than otherwise might apply to the Offered Securities.

The Ability to Resell Bonds May be Limited. During an Auction Period a beneficial owner of an Offered Security may sell, transfer or dispose of an Offered Security only in an Auction, pursuant to a Bid or Sell Order in accordance with the Dutch Auction Procedures (see "APPENDIX H- DUTCH AUCTION PROCEDURES"), or outside an Auction, to or through a Broker-Dealer. From time to time the Initial Broker-Dealers may sell auction rate securities to dealers who are not broker-dealers in the auctions for such securities for resale to the customers of such dealer. If a Holder purchases its Offered Security through a dealer which is not a Broker-Dealer for the Offered Securities, such Holder's ability to sell its Offered Securities may be affected by the continued ability of its dealer to transact trades through a Broker-Dealer. The ability to sell a Offered Security in an Auction would be adversely affected if there are not sufficient buyers willing to purchase all the Offered Securities offered for sale at a rate equal to or less than the Maximum Interest Rate. As noted in the prior paragraph, Broker-Dealers may submit Orders for their own accounts in an Auction in order to prevent the Auction from failing, they are not obligated to do so, and there is no assurance that any one or more Auctions will not fail. The ability to sell outside an Auction may also be limited. The Initial Broker-Dealers have advised FMPA that they intend to buy and sell Offered Securities for their own accounts between Auctions, as a market-maker or otherwise. The Initial Broker-Dealers have no obligation to make a market in the Offered Securities and may discontinue any such market making or other trading at any time without notice. Consequently, there is no assurance that beneficial owners of Offered Securities will be able to resell the Offered Securities on the terms or at the times they desire.

If, as noted above, the number of Offered Securities offered for sale exceeds the number offered to be purchased in any Auction, the Auction will fail and beneficial owners may not be able to sell their Offered Securities at that time. Their ability to sell outside an Auction may also be adversely affected by a relative lack of demand for the Offered Securities. The relative buying and selling interest of market participants in Offered Securities, both within and outside of an Auction, will vary over time. These variations may be affected by, among other things, news relating to FMPA, the attractiveness of alternative investments, the perceived risk of owning the Offered Securities or auction-rate securities generally (whether related to credit, liquidity or any other risk), the tax or accounting treatment accorded the Offered Securities or auction-rate securities generally (including recent clarification of U.S. generally accepted accounting principles as they apply to the accounting treatment of such securities), reactions of market participants to regulatory actions (such as those described in the next paragraph) or press reports, financial reporting cycles and market conditions generally. The willingness of a Broker-Dealer to buy Offered Securities for its own account, in an Auction or otherwise, may also vary, depending on the size of its inventory and other factors, and this could significantly affect demand for the Offered Securities. Shifts in demand for the Offered Securities in response to any one or more events cannot be predicted and may be short-lived or continue for longer periods. Consequently, beneficial owners who wish to sell their Offered Securities at a particular time may be unable to do so, either in an Auction or outside an Auction, and may have to hold their Offered Securities for a longer period than they intended, during which the market value of their Offered Securities could decline.

The SEC is Reviewing Broker-Dealer Practices in the Market for Auction-Rate Securities. According to published news reports, the staff of the Securities and Exchange Commission ("SEC") has requested information from a number of broker-dealers regarding certain of their practices involving auction-rate securities, including practices of the kind described in the preceding paragraphs. The Initial Broker-Dealers have advised FMPA that they and certain other participants in the markets for auction-rate securities, including both taxable and tax-exempt securities, have received letters from the SEC staff requesting that they voluntarily conduct a review of their practices and procedures in those markets. Pursuant to these requests, the Initial Broker-Dealers conducted their own voluntary review and reported its findings to the SEC staff. At the SEC staff's request, the Initial Broker-Dealers and certain other market participants are engaging in discussions with the SEC staff concerning its inquiry.

HEARING EXHIBIT - 00000427

No assurance can be given as to the outcome of this process or whether or how this process may affect the market for auction-rate securities generally or the Offered Securities or any Auction in particular.

Auction Agent and Broker-Dealer May Resign, Causing Auctions to Be Cancelled. The Auction Agreement provides that the Auction Agent may resign from its duties as Auction Agent by giving at least 45 days notice to FMPA and the Trustee and does not require, as a condition to the effectiveness of such resignation, that a replacement Auction Agent be in place if its fee has not been paid. The Broker-Dealer Agreement provides that the Broker-Dealer thereunder may resign upon 30 days notice or immediately, in certain circumstances, and does not require, as a condition to the effectiveness of such resignation, that a replacement Broker-Dealer be in place. For any Auction Period during which there is no duly appointed Auction Agent, or during which there is no duly appointed Broker-Dealer, it will not be possible to hold Auctions, with the result that the interest rate on the Offered Securities will be determined as described in APPENDIX H–"Auction Period–General."

Auction Periods and Dates May Change. The Auction Periods and Auction Dates may be changed by FMPA, the Auction Agent and the Broker-Dealer without amending the Dutch Auction Procedures. Thus, these changes may be made without the consent of any beneficial owner of the Offered Securities.

Redemption Provisions

Mandatory Redemption. The Series 2006B-1 Bonds are subject to mandatory redemption upon notice prior to maturity on October 1 in each of the years and in the respective principal amounts set forth below pursuant to mandatory Sinking Fund Installments (the particular bonds to be redeemed to be selected by the Trustee by lot as provided in the Resolution), in each case at a redemption price of 100% of their principal amount plus accrued interest to the date of redemption.

Year	Amount	Year	Amount
2017	$4,100,000	2023	$5,200,000
2018	4,275,000	2024	5,425,000
2018	4,450,000	2025	5,600,000
2020	4,625,000	2026	5,850,000
2021	4,800,000	2027*	6,100,000
2022	5,025,000		

*Final Maturity

The Series 2006B-2 Bonds are subject to mandatory redemption upon notice prior to maturity on October 1 in each of the years and in the respective principal amounts set forth below pursuant to mandatory Sinking Fund Installments (the particular bonds to be redeemed to be selected by the Trustee by lot as provided in the Resolution), in each case at a redemption price of 100% of their principal amount plus accrued interest to the date of redemption.

Year	Amount	Year	Amount
2017	$4,100,000	2023	$5,200,000
2018	4,275,000	2024	5,425,000
2018	4,450,000	2025	5,600,000
2020	4,625,000	2026	5,850,000
2021	4,800,000	2027*	6,100,000
2022	5,025,000		

*Final Maturity

FMPA-POD3-00018

HEARING EXHIBIT - 00000428

The Series 2006B-3 Bonds are subject to mandatory redemption upon notice prior to maturity on October 1 in each of the years and in the respective principal amounts set forth below pursuant to mandatory Sinking Fund Installments (the particular bonds to be redeemed to be selected by the Trustee by lot as provided in the Resolution), in each case at a redemption price of 100% of their principal amount plus accrued interest to the date of redemption.

Year	Amount	Year	Amount
2017	$4,100,000	2023	$5,200,000
2018	4,275,000	2024	5,425,000
2018	4,450,000	2025	5,600,000
2020	4,625,000	2026	5,850,000
2021	4,800,000	2027*	6,100,000
2022	5,025,000		

*Final Maturity

The Series 2006B-4 Bonds are subject to mandatory redemption upon notice prior to maturity on October 1 in each of the years and in the respective principal amounts set forth below pursuant to mandatory Sinking Fund Installments (the particular bonds to be redeemed to be selected by the Trustee by lot as provided in the Resolution), in each case at a redemption price of 100% of their principal amount plus accrued interest to the date of redemption.

Year	Amount	Year	Amount
2017	$4,525,000	2027	$ 850,000
2018	4,150,000	2028	850,000
2018	4,100,000	2029	850,000
2020	4,250,000	2030	850,000
2021	4,425,000	2031	850,000
2022	3,325,000	2032	850,000
2023	3,450,000	2033	850,000
2024	3,600,000	2034	850,000
2025	8,700,000	2035*	8,000,000
2026	4,150,000		

*Final Maturity

Optional Redemption. The Offered Securities bearing interest at a Dutch Auction Rate are subject to redemption prior to maturity at the election of FMPA, as a whole or in part, on the Business Day immediately following an Auction Date. Such Offered Securities will be redeemed at a Redemption Price equal to 100% of the principal amount thereof, plus accrued interest thereon, if any.

To effect such an optional redemption, FMPA must pay or cause to be paid to the Trustee, in advance of notice to the Holders of such redemption (which notice must be given to such Holders at least 12 days prior to the redemption date), amounts sufficient to pay 100% of the principal amount of the Offered Securities to be redeemed on the redemption date.

Redemption Procedures. In the event of redemption of less than all of the Outstanding Offered Securities, the Trustee will select the Offered Securities to be redeemed in such manner as the Trustee deems fair and appropriate. The Trustee will mail any required notice of redemption to the registered Holders of any Offered Securities or portions thereof which are to be redeemed, but receipt of such notice will not be a condition precedent to such redemption, and failure to receive any such notice will not affect the validity of the proceedings for the redemption of Offered Securities as to which proper mailing was made. New Offered Securities representing the unredeemed balance of the principal amount of any such Offered Securities shall be issued to the registered owner thereof (which shall be Cede & Co., as Securities Depository Nominee of DTC, for so long as the system of registration described in APPENDIX E—"BOOK-ENTRY-ONLY SYSTEM" shall be in effect), without charge

FMPA-POD3-00019

HEARING EXHIBIT - 00000429

therefor, in any authorized denominations in an aggregate unpaid principal amount equal to the unredeemed portion of the Offered Securities surrendered.

If the Offered Securities are being held by DTC under the book-entry system and less than all of such Offered Securities within a maturity are being redeemed, DTC's current practice is to determine by lot the amount of the ownership interest of each DTC Participant in such maturity to be called for redemption, and each DTC Participant is to then select by lot the ownership interest in such maturity to be redeemed. See APPENDIX E—"BOOK-ENTRY-ONLY SYSTEM."

Notice of Redemption. In the event that any of the Offered Securities are called for redemption, the Trustee must give notice, in the name of FMPA, of the redemption of such Offered Securities, which notice must specify the date of redemption, the Redemption Price and the place or places where amounts due upon such redemption will be payable and, if less than all of the Offered Securities are to be redeemed, the numbers of such Offered Securities and the principal portions thereof to be redeemed. Such notice shall further state that on such date thereof there shall become due and payable upon such Offered Securities or portions thereof to be redeemed the Redemption Price, together with interest accrued to the redemption date, if such redemption date is not an Interest Payment Date, and that from and after the redemption date interest thereon shall cease to accrue and be payable.

Any notice of optional redemption may state that it is conditional upon receipt by the Trustee of monies sufficient to pay the Redemption Price of the Offered Securities or upon the satisfaction of any other condition, or that it may be rescinded upon the occurrence of any other event. Any such conditional notice may be rescinded at any time before payment of the Redemption Price if any specified condition is not satisfied or any specified event occurs. Notice of such rescission shall be given by the Trustee to affected Bondholders as promptly as practicable upon the failure of such condition or the occurrence of such event.

For so long as the Offered Securities are registered in the name of DTC or its nominee, notice of redemption, or any rescission thereof, of any Offered Securities will be given by the Trustee to DTC or such nominee only. See APPENDIX E-"BOOK-ENTRY-ONLY SYSTEM."

PLAN OF FINANCE

The proceeds of the Series 2006B Bonds, together with the proceeds the Series 2006A Bonds, will be used to provide a portion of the funds needed to (i) finance the acquisition and construction of the Treasure Coast Energy Center, (ii) finance certain obligations of FMPA relating to Public Gas Partners, (iii) refinance certain loans of FMPA related to the Project and (iv) pay the costs of issuance of the Series 2006A Bonds and Series 2006B Bonds. For a description of the interest rate swap agreements to be terminated, see "RISK MANAGEMENT—Interest Rate Swap Agreements." For a description of the Treasure Coast Energy Center, see "THE PROJECT—Future Power Supply." For a description of the Public Gas Partners, see "THE PROJECT—Fuel Supply."

The proceeds of the Series 2006C Bonds, will be used to finance certain other obligations of FMPA related to Public Gas Partners and pay the costs of issuance of the Series 2006C Bonds.

FMPA-POD3-00020
HEARING EXHIBIT - 00000430

ESTIMATED SOURCES AND USES OF FUNDS

The following table sets forth the estimated sources and uses of funds for the Offered Securities, Series 2006B Bonds and Series 2006C Bonds:

Sources	
Principal Amount of the Series 2006A Bonds	$ 125,020,000
Net Original Issue Premium on the Series 2006A Bonds	1,742,148
Principal Amount of the Series 2006B Bonds	225,825,000
Principal Amount of the Series 2006C Bonds	45,000,000
Total	$397,587,148
Uses	
Deposit to Construction Fund	$382,716,850
Capitalized Interest	11,242,440
Costs of Issuance[1]	3,627,858
Total	$397,587,148

[1] Including the fees and expenses of attorneys, accountants and advisors, printing expenses, the bond insurance premium and underwriters' discount.

HEARING EXHIBIT - 00000431

DEBT SERVICE REQUIREMENTS

The following schedule shows the debt service requirements for the Offered Securities, the Series 2006A Bonds, the Series 2003A Bonds, the Series 2003B Bonds the Series 2000 Bonds, the Series 2000-1 Bonds and the Series 2000-2 Bonds:

Period Ending October 1	Series 2006A Bonds Debt Service		Series 2006B Bonds and Series 2006C Bonds Debt Service		Debt Service on Outstanding Bonds[3]	Aggregate Debt Service on All Bonds
	Principal	Interest[1]	Principal	Interest[2]		
2006		$ 2,556,856	-	$ 5,355,978	$ 14,369,017	$ 22,281,851
2007	$ 2,640,000	5,085,459	-	10,652,774	14,340,629	32,718,862
2008	11,210,000	4,993,059	-	10,652,774	14,287,610	41,143,443
2009	11,755,000	4,490,234	-	10,652,774	14,391,783	41,289,791
2010	12,275,000	3,976,684	-	10,652,774	14,363,876	41,268,334
2011	12,875,000	3,472,059	-	10,652,774	14,373,218	41,373,051
2012	13,540,000	2,926,409	-	10,652,774	14,337,311	41,456,494
2013	14,205,000	2,338,159	-	10,652,774	14,372,422	41,568,355
2014	14,265,000	1,809,220	-	10,652,774	14,395,120	41,122,114
2015	15,865,000	1,267,637	-	10,652,774	13,369,798	41,155,209
2016	16,390,000	655,248	-	10,652,774	13,363,756	41,061,778
2017	-	-	$16,825,000	10,652,774	13,398,018	40,875,792
2018	-	-	16,975,000	10,033,621	13,370,546	40,379,167
2019	-	-	17,450,000	9,408,835	13,383,502	40,242,337
2020	-	-	18,125,000	8,766,534	13,409,600	40,301,134
2021	-	-	18,825,000	8,099,407	13,423,070	40,347,477
2022	-	-	18,400,000	7,406,540	13,448,909	39,255,449
2023	-	-	19,050,000	6,728,988	13,436,101	39,215,089
2024	-	-	19,875,000	6,027,535	13,460,539	39,363,074
2025	-	-	70,500,000	5,295,732	33,595,434	109,391,166
2026	-	-	21,700,000	2,025,881	2,577,275	26,303,156
2027	-	-	19,150,000	1,226,974	2,577,275	22,954,249
2028	-	-	850,000	521,312	2,577,275	3,948,587
2029	-	-	850,000	489,547	2,577,275	3,916,822
2030	-	-	850,000	457,783	72,577,275	73,885,058
2031	-	-	850,000	426,018	-	1,276,018
2032	-	-	850,000	394,254	-	1,244,254
2033	-	-	850,000	362,489	-	1,212,489
2034	-	-	850,000	330,725	-	1,180,725
2035	-	-	8,000,000	298,960	-	8,298,960
Total:	$125,020,000	$33,571,022	$270,825,000	$190,837,622	$379,776,634	$1,000,030,278

(1) Based on a swap rate of 3.72%, 3.79%, 3.86%, and 3.91% for the CPI Bonds maturing in 2013, 2014, 2015, and 2016, respectively.
(2) Based on an assumed weighted average swap rate of 3.688% for the Series 2006B Bonds and 5.175% for the Series 2006C Bonds.
(3) Based on a swap rate of 3.581% for the Series 2003B-1 Bonds, 4.0765% for the Series 2003B-2 Bonds, 3.669% for the Series 2000 Bonds, 3.667% for the Series 2000-1 Bonds and a weighted average swap rate of 3.6929% for the Series 2000-2 Bonds.

FMPA-POD3-00022

HEARING EXHIBIT - 00000432

RISK MANAGEMENT

General

The Agency has formalized its risk management activities through the creation and adoption by its Board of an Agency-wide risk management program. The FMPA Board created a Risk Oversight Committee ("ROC") in fiscal year 2002 and has adopted several risk-related policies to guide Agency activities since then. These policies include its Agency-wide risk management, energy risk management, investments, debt, credit, and insurance policies. Additional policies covering other areas such as general financial policies, power supply and resource planning, operations, contract management, human resources, records and data management, contingency and disaster planning, statutory and regulatory matter have been directed by the ROC to be written and presented to the FMPA Board for adoption. Policy-specific staff members comprise a Risk Management Group ("RMG"), chaired by the Agency's risk manager, who also serves as its Assistant General Manager and CFO.

Natural Gas Supply

An area of great interest to Participants has been controlling the financial impact of highly volatile natural gas prices. Fuel costs and purchased power cost keyed to natural gas prices represents more than a third of the Project's total budget. In response, the Agency has hired specialized staff, familiar with the energy financial markets and the use of hedging as a financial strategy. Currently the Project has over 3743 natural gas futures and options contracts, cleared through Calyon Financial, Inc., with some back- and mid- office support from The Energy Authority. These NYMEX hedges cover the period from March 2006 out to December 2008. A multi-year hedging approach is taken with hedge levels (of total price exposure to natural gas) determined by Board policy. Statistical modeling tools are used to help the RMG decide hedge levels within parameters set by the Board. Since inception, volatility in the Project's natural gas costs has diminished relative to market movements. The Project manages its exposure to NYMEX margin requirements by (i) employing a rate-making process which responds quickly and automatically to cash needs and (ii) maintaining the line of credit with Wachovia. A discussion of the natural gas futures and options contracts used by FMPA in its natural gas supply management program is included in Note VI. B. "Derivative Financial Instruments—Natural Gas Futures Contracts and Options" in the audited financial statements included in FMPA's Annual Audit Report for its fiscal year ended September 30, 2005. See "FMPA FINANCIAL STATEMENTS" for direction as to how to obtain FMPA Annual Audit Reports.

Rate Setting

In response to a volatile fuel cost environment, the FMPA Board approved two changes at its February 2006 meeting. All Project rates – energy, demand and transmission – will have, effective March 1, 2006, automatic monthly cost adjustments. Tied to its Operating and Maintenance Fund cash position and the cash balance target which is set by Board policy, the rate process includes a base rate and a cost adjustment factor which is calculated to maintain the Project's cash target, given the cost outlook for the following four months. This new billing structure makes automatic the rate change process, not requiring any action by the governing body and increases the speed that over and under recoveries are dealt with through the billing process. The contracts require that all expenses of the Project be paid by participants. This new billing process increases the speed in which recoveries take place. This new approach replaces a cost-recovery process which was completed either over a one or two year period and was subject to review and confirmation at the next regularly scheduled All Requirements Project Participant meeting.

At its February 2006 meeting FMPA's Board also approved increasing an existing line of credit with Wachovia from $50 million to $100 million. This action was taken in recognition of the possibilities, although remote, that very significant swings in the costs of the Project could outpace the newly adopted billing and rate change process.

Interest Rate Swaps

As part of its debt management policy, FMPA uses interest rate swap agreements to lower borrowing costs and reduce the risk of fluctuating interest rates. By entering into interest rate swap agreements that exchange

FMPA-POD3-00023

HEARING EXHIBIT - 00000433

variable payments for fixed payments, FMPA effectively achieves a lower interest rate than it would have had it issued fixed rate debt while at the same time producing a more certain liability than it would have had it not hedged its variable rate liability. A discussion of the interest rate swap agreements employed by FMPA in its debt management program is included in Note VI. A. "Derivative Financial Instruments—Swap Agreements" in the audited financial statements included in FMPA's Annual Audit Report for its fiscal year ended September 30, 2005. See "FMPA FINANCIAL STATEMENTS" for direction as to how to obtain FMPA Annual Audit Reports.

In December 2005, FMPA entered into a series of floating to fixed rate interest rate swap agreements on a forward basis having a combined notional amount of $451,339,000 in order to hedge the risk of increases in interest rates prior to the issuance of the Offered Securities, the Series 2006A Bonds and Bonds expected to be issued related to PGP Pool No. 1 (as defined herein). Since FMPA has made certain changes in the proposed structure of its financing involving the Offered Securities and the Series 2006A Bonds, principally its determination to issue the Series 2006A Bonds as fixed rate bonds, it expects to terminate approximately $125,544,000 in notional amount of the swaps in connection with the issuance of the Offered Securities and the Series 2006A Bonds. It is anticipated that such termination will be accomplished in general by reducing a pro rata portion of each related swap representing notional amounts previously intended to be amortized between 2007 and 2016. The remaining portion of each related swap will remain in effect and will relate to the Series 2006B Bonds and the Series 2006C Bonds, respectively, as described below.

The counterparties to the interest rate swap agreements relating to the Series 2006B Bonds are Merrill Lynch Capital Services, Inc., with a guarantee provided by Merrill Lynch & Co., Inc., Goldman Sachs Capital Markets, L.P. , with a guarantee provided by The Goldman Sachs Group, Inc., Morgan Stanley Capital Services Inc., with a guarantee provided by Morgan Stanley, Bear Stearns Capital Markets Inc., with a guarantee provided by The Bear Stearns Companies, Inc., Wachovia and JPMorgan Chase Bank, National Association ("JPMorgan"). Pursuant to the terms of such interest rate swap agreements, on certain periodic payment dates FMPA will make periodic payments to the respective counterparties computed on the basis of fixed rates of interest ranging from 3.612% to 3.737% and the counterparties will make periodic payments to FMPA computed on the basis of variable rates of interest based on a percentage of LIBOR, provided, however that only the net amounts due to either FMPA or the respective counterparties will be paid on such periodic payment dates. The periodic payments to be made by FMPA will be secured on a parity with FMPA's obligations to pay principal and interest on the Series 2006B Bonds. Such interest rate swap agreements will remain in effect, subject to scheduled reduction of notional amounts corresponding to scheduled amortization of the Series 2006B Bonds, until their scheduled termination dates which occur on October 1, 2026, October 1, 2027 and October 1, 2035, unless terminated sooner in accordance with their terms.

Wachovia is the sole counterparty to the interest rate swap agreement relating to the Series 2006C Bonds. Pursuant to such interest rate swap agreement, on certain periodic payment dates FMPA will make periodic payments to Wachovia computed on the basis of a fixed rate of interest of 5.175% and Wachovia will make periodic payments to FMPA computed on the basis of a variable rate of interest based on LIBOR, provided, however that only the net amounts due to either FMPA or Wachovia will be paid on such periodic payment dates. The periodic payments to be made by FMPA will be secured on a parity with FMPA's obligations to pay principal and interest on the Series 2006C Bonds. The interest rate swap agreement with Wachovia is scheduled to terminate on October 1, 2025 (unless terminated sooner in accordance with its terms), and it had a notional amount of $50,000,000 as of its trade date of December 9, 2005.

In connection with the issuance of certain of the Series 2006A Bonds maturing in 2013, 2014, 2015, and 2016 (the "CPI Bonds"), FMPA has entered into interest rate swap agreements (the "2006 Hedge Agreements") with Merrill Lynch Capital Services, Inc. and Morgan Stanley Capital Services Inc. (the "2006 Hedge Providers"). The aggregate notional amount under the 2006 Hedge Agreements is equal to the aggregate principal amount of the CPI Bonds. The 2006 Hedge Agreements provide that FMPA will pay to the 2006 Hedge Providers fixed rates of 3.72%, 3.79%, 3.86%, and 3.91% on the notional amounts associated with the CPI Bonds maturing in 2013, 2014, 2015, and 2016, respectively, and the 2006 Hedge Providers will pay to FMPA a floating amount on such notional amounts based on a rate of interest based on the change in the consumer price index over a one year period plus a spread for the respective maturities of the CPI Bonds, provided, however that only the net amounts due to either FMPA or the respective 2006 Hedge Providers will be paid on such periodic payment dates. The 2006 Hedge Agreements are Qualified Swaps under the Resolution. FMPA's payments to the 2006 Hedge Providers under the

HEARING EXHIBIT - 00000434

2006 Hedge Agreements are secured on a parity with FMPA's obligations to pay principal and interest on the Series 2006A Bonds. The obligation of the 2006 Hedge Providers to make scheduled payments under the 2006 Hedge Agreements is separately guaranteed by their respective corporate parents, Merrill Lynch & Co., Inc. and Morgan Stanley. Failure of any 2006 Hedge Provider to make any scheduled payment to FMPA under any 2006 Hedge Agreement will not affect FMPA's obligations to pay the principal of and interest on the CPI Bonds when due.

UBS AG is the sole counterparty to the interest rate swap agreement relating to Bonds expected to be issued in connection with the financing of PGP Pool No. 1 ("PGP No. 1 Bonds"). Pursuant to such interest rate swap agreement, on certain periodic payment dates FMPA will make periodic payments to UBS AG computed on the basis of a fixed rate of interest of 3.745% and UBS AG will make periodic payments to FMPA computed on the basis of a variable rate of interest based on a percentage of LIBOR, provided, however that only the net amounts due to either FMPA or UBS AG will be paid on such periodic payment dates. The periodic payments to be made by FMPA will be secured on a parity with FMPA's obligations to pay principal and interest on the PGP No. 1 Bonds. The interest rate swap agreement with UBS AG is scheduled to terminate on October 1, 2025 (unless terminated sooner in accordance with its terms), and it has a notional amount of $55,000,000.

The senior unsecured debt of Merrill Lynch & Co., Inc. is currently rated "Aa3" and "A+" by Moody's and Standard & Poor's, respectively. The senior unsecured debt of Goldman Sachs Group, Inc. is currently rated "Aa3" and "A+" by Moody's and Standard & Poor's, respectively. The senior unsecured debt of Morgan Stanley is currently rated "Aa3" and "A+" by Moody's and Standard & Poor's, respectively. The senior unsecured debt of Wachovia is currently rated "Aa2" and "AA-" by Moody's and Standard & Poor's, respectively. The senior unsecured debt of UBS AG is currently rated "Aa2" and "AA+" by Moody's and Standard & Poor's, respectively. The senior unsecured debt of The Bear Stearns Companies, Inc. is currently rated "A1" and "A" by Moody's and Standard & Poor's, respectively. The senior unsecured debt of JPMorgan is currently rated "Aa2" and "AA-" by Moody's and Standard & Poor's, respectively.

In connection with the issuance of the Series 2003B Bonds, FMPA entered into two floating to fixed rate interest rate swap agreements, each scheduled to terminate on October 1, 2025 (unless terminated sooner in accordance with its terms) and having a combined notional amount of $90,975,000 as of their trade date of July 8, 2003, with JPMorgan and Citibank, N.A., New York, respectively, as counterparties. Pursuant to such interest rate swap agreements, on certain periodic payment dates FMPA will make periodic payments to the respective counterparties computed on the basis of fixed rates of interest ranging from 3.581% to 4.0765% and the counterparties will make periodic payments to FMPA computed on the basis of variable rates of interest based on the BMA Index or a percentage of LIBOR, as the case may be, provided, however that only the net amounts due to either FMPA or the counterparties will be paid on such periodic payment dates. The periodic payments to be made by FMPA will be secured on a parity with FMPA's obligations to pay principal and interest on the Series 2003B Bonds.

The senior unsecured debt of Citibank, N.A., New York is currently rated "Aa1" and "AA" by Moody's and Standard & Poor's, respectively.

FMPA entered into a floating to fixed rate interest rate swap agreement relating to the Series 2000 Bonds scheduled to terminate on October 1, 2025 (unless terminated sooner in accordance with its terms) and having a notional amount of $20,125,000 as of its trade date of December 21, 2005, with UBS AG, as counterparty. Pursuant to such interest rate swap agreement, on certain periodic payment dates FMPA will make periodic payments to the counterparty computed on the basis of ă fixed rate of interest of 3.669% and the counterparty will make periodic payments to FMPA computed on the basis of variable rates of interest based on a percentage of LIBOR, provided, however that only the net amounts due to either FMPA or the counterparty will be paid on such periodic payment dates. The periodic payments to be made by FMPA will be secured on a parity with FMPA's obligations to pay principal and interest on the Series 2000 Bonds.

FMPA entered into a floating to fixed rate interest rate swap agreement relating to the Series 2000-1 Bonds scheduled to terminate on October 1, 2030 (unless terminated sooner in accordance with its terms) and having a notional amount of $30,000,000 as of its trade date of December 22, 2005, with JPMorgan, as counterparty. Pursuant to such interest rate swap agreement, on certain periodic payment dates FMPA will make periodic payments to the counterparty computed on the basis of a fixed rate of interest of 3.667% and the counterparty will

HEARING EXHIBIT - 00000435

make periodic payments to FMPA computed on the basis of variable rates of interest based on a percentage of LIBOR, provided, however that only the net amounts due to either FMPA or the counterparty will be paid on such periodic payment dates. The periodic payments to be made by FMPA will be secured on a parity with FMPA's obligations to pay principal and interest on the Series 2000-1 Bonds.

FMPA entered into two floating to fixed rate interest rate swap agreements relating to the Series 2000-2 Bonds each scheduled to terminate on October 1, 2030 (unless terminated sooner in accordance with its terms) and having a combined notional amount of $40,000,000 as of their trade dates of December 21, 2005 and December 22, 2005, with Bear Stearns and JPMorgan, respectively, as counterparties. Pursuant to such interest rate swap agreements, on certain periodic payment dates FMPA will make periodic payments to the respective counterparties computed on the basis of fixed rates of interest ranging from 3.667% to 3.7085% and the counterparties will make periodic payments to FMPA computed on the basis of variable rates of interest based on a percentage of LIBOR, provided, however that only the net amounts due to either FMPA or the counterparties will be paid on such periodic payment dates. The periodic payments to be made by FMPA will be secured on a parity with FMPA's obligations to pay principal and interest on the Series 2000-2 Bonds.

Arrangements made under the Interest Rate Swap Agreements do not alter FMPA's obligation to pay principal of and interest on the Series 2006B Bonds, the Series 2006C Bonds, the Series 2003B Bonds, the Series 2000 Bonds, the Series 2000-1 Bonds or the Series 2000-2 Bonds.

UNDER CERTAIN CIRCUMSTANCES, EACH INTEREST RATE SWAP AGREEMENT IS SUBJECT TO EARLY TERMINATION AS STIPULATED BY ITS TERMS. IN THE EVENT OF ANY SUCH EARLY TERMINATION, FMPA WOULD STILL BE OBLIGATED TO PAY THE RATE ESTABLISHED FOR SERIES 2006B BONDS, SERIES 2006C BONDS, SERIES 2003B BONDS, SERIES 2000 BONDS, SERIES 2000-1 BONDS OR SERIES 2002-2 BONDS, AS THE CASE MAY BE, AND FMPA COULD BE REQUIRED TO MAKE A TERMINATION PAYMENT TO THE RESPECTIVE COUNTERPARTY. DEPENDING UPON MARKET CONDITIONS AT THE TIME OF ANY SUCH EARLY TERMINATION, THE TERMINATION FEE PAYABLE BY FMPA COULD BE SUBSTANTIAL. PURSUANT TO THE INTEREST RATE SWAP AGREEMENTS, ANY SUCH TERMINATION PAYMENT WOULD BE SUBORDINATE TO PAYMENT OF DEBT SERVICE ON THE SERIES 2006A BONDS, SERIES 2006B BONDS, SERIES 2006C BONDS, SERIES 2003B BONDS, SERIES 2000 BONDS, SERIES 2000-1 BONDS OR SERIES 2002-2 BONDS.

SECURITY AND SOURCES OF PAYMENT FOR THE OFFERED SECURITIES

Pledge under the Resolution

The principal of and premium, if any, and interest on all Bonds issued under the Resolution, including the Offered Securities and any Additional Bonds hereafter issued and any Parity Debt are payable solely from and secured as to payment of the principal and redemption price thereof, and interest thereon, in accordance with their terms and the provisions of the Resolution solely by (i) proceeds of the sale of the Offered Securities, (ii) all right, title and interest of FMPA in, to and under the Power Supply Contracts, (iii) the Revenues and (iv) all funds established by the Resolution including investment income, if any, thereof, subject only to the provisions of the Resolution permitting the application thereof for the purposes and on the terms and conditions set forth in the Resolution.

The Offered Securities are direct and special obligations of FMPA payable solely out of the Revenues and other funds pledged thereto under the Resolution as described above. Neither the State of Florida nor any political subdivision thereof nor any city or other entity which is a member of FMPA, other than FMPA, is obligated to pay the principal of and premium, if any, and interest on the Offered Securities, and neither the faith and credit nor the taxing power of the State of Florida or any political subdivision thereof or of any city or other entity is pledged to the payment of the principal of and premium, if any, and interest on the Offered Securities. FMPA has no taxing power. FMPA may issue Additional Bonds on a parity basis with the Offered Securities pursuant to the Resolution.

HEARING EXHIBIT - 00000436

For a more extensive discussion of the terms and provisions of the Resolution, the levels at which the funds and accounts established thereby are to be maintained and the purposes to which moneys in such funds and accounts may be applied, see APPENDIX C - SUMMARY OF CERTAIN PROVISIONS OF THE RESOLUTION AND THE POWER SUPPLY CONTRACTS."

Rates

FMPA has covenanted in the Resolution to fix, establish, maintain and collect rents, rates, fees and charges under the Power Supply Contracts and to otherwise charge and collect rents, rates, fees and charges for the use or the sale of the output, electric capacity and energy or service of the System which, together with other available Revenues, are reasonably expected to yield Net Revenues for the twelve-month period commencing with the effective date of such rents, rates and charges which shall be equal to at least the Aggregate Debt Service for such period and, in any event, as shall be required, together with other available funds, to pay or discharge all other indebtedness, charges and liens whatsoever payable out of Revenues under the Resolution, excluding from Aggregate Debt Service for purposes of the foregoing, a Refundable Principal Installment, but only to the extent that FMPA intends to pay such Refundable Principal Installment from sources other than Revenues.

Each Participant is required by the terms of its respective Power Supply Contract to establish, levy and collect rents, rates and other charges for the products and services provided by its electric or integrated utility system, which rents, rates and other charges shall be at least sufficient (i) to meet the operation and maintenance expenses of such electric or integrated utility system, (ii) to comply with all covenants pertaining thereto contained in, and all other provisions of, any resolution, trust indenture, or other security agreement relating to any bonds or other evidences of indebtedness issued or to be issued by the Participant, (iii) to generate funds sufficient to fulfill the terms of all other contracts and agreements made by the Participant, including, without limitation, its Power Supply Contract, and (iv) to pay all other amounts payable from or constituting a lien or charge on the revenues of its electric or integrated utility system.

See "RISK MANAGEMENT—Rate Setting."

All-Requirements Power Supply Contracts

The Power Supply Contracts provide for payments by the Participants of amounts sufficient to pay debt service on all Bonds (including the Offered Securities) and Subordinated Debt, and all other payments required by the Resolution, such as operation and maintenance costs of the Project and deposits to reserves. See "THE POWER SUPPLY CONTRACTS" and See "THE PROJECT-Member Contributed Resources."

Additional Bonds

FMPA may, upon compliance with certain terms and conditions set forth in the Resolution, issue additional bonds for the purpose of (i) providing additional funds to finance costs incurred by FMPA in connection with the All-Requirements Project, including developmental costs, costs of acquisition and construction of additional power supply resources, operating costs and retirement costs and (ii) refunding any of the Bonds then outstanding under the Resolution ("Additional Bonds").

Possible Consolidation of Other Projects Into the Project and Addition of Participants to the Project

The bond resolutions for certain other FMPA projects provide that under certain circumstances FMPA could issue Additional Bonds in exchange for the outstanding bonds for such projects and consolidate them with the Project. Such a consolidation could result in the addition of new Participants, the addition of new power resources to the Project and the incurrence of Additional Bonds. In order for such a consolidation to occur, FMPA would have to meet the test for the Additional Bonds to be issued under the Resolution. FMPA cannot predict the likelihood or timing of any such consolidation.

FMPA-POD3-00027

HEARING EXHIBIT - 00000437

Flow of Funds Under the Resolution

Pursuant to the Resolution, all Revenues are deposited with FMPA to the credit of the Revenue Fund. Each month funds are to be transferred from the Revenue Fund in the following amounts and in the order of priority set forth below:

First, to the Operation and Maintenance Fund held by FMPA (i) for credit to the Operation and Maintenance Account in the amount, if any, required so that the balance credited to said Account equals the amount estimated to be necessary for the payment of Operation and Maintenance Expenses for the succeeding month, (ii) for credit to the Working Capital Account in the amount budgeted, if any, required so that the balance credited to said Account equals the amount budgeted therefore, and (iii) for credit to the Rate Stabilization Account Reserve in the amount, if any, required so that the balance credited to said Account equals the amount so budgeted therefore.

Second, to the Debt Service Fund held by the Trustee for credit to the Debt Service Account, the amount required so that the balance in such Account (excluding capitalized interest on deposit therein in excess of the amount thereof to be applied to pay interest accrued and to accrue on all outstanding Bonds for the Period) shall equal the Accrued Aggregate Debt Service;

Third, to reimburse each Reserve Account Credit Facility Provider for any amounts advanced under its Reserve Account Credit Facility;

Fourth, to the Debt Service Fund held by the Trustee for credit to each subaccount of the Debt Service Reserve Account, the amount required for such subaccount to equal the Debt Service Reserve Requirement;

Fifth, to the Subordinated Debt Fund maintained and held as determined by the Supplemental Resolution, the amount, if any, required to pay principal or sinking fund installments of or premium, if any, and interest on each issue of Subordinated Debt and reserves therefor, as required by the Supplemental Resolution authorizing such issue of Subordinated Debt;

Sixth, for credit to the Reserve and Contingency Fund maintained and held by FMPA (i) for credit to the Renewal and Replacement Account, the amount budgeted therefor and (ii) for credit to the Contingency Account, the amount required for such account to equal the Contingency Requirement;

Seventh, for credit to the Decommissioning Fund, if one has been established pursuant to the Resolution, the amount budgeted for credit to such fund for the month, if any and

Eight, for credit to the General Reserve Fund maintained and held by FMPA, the remaining balance, if any, of moneys in the Revenue Fund.

Debt Service Reserve

There is no Debt Service Reserve Requirement for the Offered Securities.

THE POWER SUPPLY CONTRACTS

Introduction

Each Participant in the Project has entered into a Power Supply Contract with FMPA. Subject to the early withdrawal from the Project of a Participant, as discussed below, each Power Supply Contract had an initial term of 30 years. Each year the Power Supply Contract is automatically extended for one additional year so that it will always have a term of at least 30 years unless a Project Participant affirmatively elects, upon one year's prior notice to FMPA, not to extend the Power Supply Contract. Except for the Power Supply Contracts with respect to Starke and Green Cove Springs, as described below, the All-Requirements Power Supply Contracts will remain in effect until at least October 1, 2037.

FMPA-POD3-00028

HEARING EXHIBIT - 00000438

In 2003 and 2005, respectively, Starke and Green Cove Springs each gave notice to FMPA of its election not to extend its respective Power Supply Contract. Upon expiration of their respective contracts in 2036 and 2037, respectively, Starke and Green Cove Springs will no longer be Participants in the Project. See "PROJECT PARTICIPANTS— Change in Status of Certain Participants."

In December 2004, Vero Beach gave notice that it was exercising its contractual right to reduce its obligation to purchase electric power and energy to a contract rate of delivery as defined in the Power Sales Contract. Beginning in 2010 and continuing for the term of the Power Sales Contract, the Project will serve Vero Beach with a load to be calculated in December 2009 (currently estimated to be approximately 33 MW). At the time of such withdrawal, Vero Beach will no longer sell capacity and energy to the Project under its Capacity and Energy Sales Contract. See "PROJECT PARTICIPANTS— Change in Status of Certain Participants " and "Contract Rate of Delivery" below.

Purchase and Sale

Under the Power Supply Contract with a particular Participant, FMPA agrees to sell and deliver to that Participant, and that Participant agrees to purchase from FMPA, that Participant's "All-Requirements Service." For a particular Participant, its All-Requirement Service is all of the electric power and energy, transmission and associated services except for energy supplied by the excluded resources which consist of entitlement shares in the St. Lucie Project and ownership shares of Crystal River Unit No. 3. If and to the extent that such Participant has any Excluded Power Supply Resources, FMPA agrees to sell and deliver to such Participant and such Participant agrees to purchase and receive from FMPA generating support services for such Excluded Power Supply Resources including reserves, deficiency energy, transmission losses and firming capacity associated with the delivery of the Excluded Power Supply Resources or the replacement thereof and any associated transmission and dispatching services (the "Back-up and Support Services").

Early Termination of a Power Supply Contract

A Participant may, but only upon satisfaction of the conditions described below, terminate its Power Supply Contract by written notice given at least three years prior to the intended Withdrawal Date (which date must be a September 30). Any such notice by the Participant shall be irrevocable.

The conditions which must be satisfied before any such withdrawal may occur include: (i)(a) payment by the withdrawing Participant of an amount in cash equal to the amount necessary to call a percentage of Bonds and Subordinated Debt equal to the withdrawing Participant's share of the current total energy load of the Project plus (b) the payment of the present value of all additional costs FMPA determines at its sole discretion may be incurred as a result of such withdrawal; (ii) the obtaining of any required approval of any credit facility providers if any Bonds and Subordinated Debt are then secured by a credit facility; (iii) the confirmation of then effective ratings on any Bonds and Subordinated Debt not secured by a credit facility and rated by a national rating agency; and (iv) a determination by bond counsel for FMPA that such withdrawal does not adversely affect the exclusion from gross income for Federal tax purposes of and/or the State of Florida tax exemption of interest on outstanding or future Bond and Subordinated Debt. Within 180 days after the first anniversary of the Withdrawal Date and annually thereafter for the remaining term of the withdrawing Participants' Power Supply Contract, FMPA will reimburse the Participant in an amount equal to the additional benefits, if any, actually received by FMPA during such preceding year as a result of the withdrawal from the Project by the Participant as solely determined by FMPA. The net amount of such payments by FMPA to the Participant shall not exceed 90% of the payment made by the Participant to FMPA under clause (i)(b) above.

See APPENDIX C - "SUMMARY OF CERTAIN PROVISIONS OF THE RESOLUTION AND THE POWER SUPPLY CONTRACTS."

Contract Rate of Delivery

Effective on any January 1 upon at least five years' prior written notice to FMPA prior to that January 1, a Participant may limit the maximum amount of electric capacity and energy required as All–Requirements Service

FMPA-POD3-00029

HEARING EXHIBIT - 00000439

for the remainder of the term of its Power Supply Contract so as not to exceed the "Contract Rate of Delivery." The Contract Rate of Delivery is the peak demand of a Participant for electric capacity and energy as All-Requirements Service under the Power Supply Contract during the preceding twelve-month period preceding the date one month prior to the date that such limitation shall become effective, adjusted up or down by FMPA by not more than fifteen percent reserve margin, so as to provide optimal utilization of the FMPA power supply resources, such adjustment to be made by FMPA in its sole discretion, and subject to certain other reductions relating to capacity available from the Participant's own generating facilities and from contractual arrangements under which the Participant is entitled to receive capacity and energy, including contracts relating to other FMPA projects. The obligations of FMPA and a particular Participant in respect to the Back-up and Support Services will not be affected in any way by an election of such Participant to limit its obligation to its Contract Rate of Delivery. As discussed above, in December 2004, Vero Beach notified FMPA of its intent to limit its obligations under its Power Supply Contract to its Contract Rate of Delivery effective January 1, 2010.

Payments under Power Supply Contracts

Payments made under the Power Supply Contracts are payable solely from the Participants' electric or integrated utility system revenues. Payments by a Participant under its Power Supply Contract are operating expenses of the Participant's electric or integrated utility system, payable on a parity with the system's operation and maintenance expenses and before debt service on the system's senior and subordinated debt.

The Power Supply Contracts may not be amended, terminated or modified in any manner which will materially adversely affect the security for the Offered Securities.

See APPENDIX C - "SUMMARY OF CERTAIN PROVISIONS OF THE RESOLUTION AND THE POWER SUPPLY CONTRACTS - Summary of Certain Provisions of the Power Supply Contracts. See also "STATE REGULATION" and "PROJECT PARTICIPANTS— Change in Status of Certain Participants " herein.

BOND INSURANCE

General

It is a condition to the issuance of the Offered Securities that the Insurer issue the Policies. The Insurer has agreed, subject to the provisions of its commitment, to issue the Policies concurrently with the initial issuance of the Offered Securities.

The following provisions of the Supplement Resolution and Bond Series Certificate will apply to the Insurer: (a) No provision of the Supplemental Resolution or the Bond Series Certificate expressly recognizing or granting rights in or to the Insurer may be amended in any way that affects such rights without the prior written consent of the Insurer; (b) the Insurer's consent is required, in lieu of consent of the Holders of the Offered Securities, to execute and deliver certain supplemental resolutions or to amend or supplement the Power Supply Contracts, to remove the Trustee or Paying Agent and appoint a successor trustee or paying agent, or to take any other action which requires the consent of the Holders; and (c) upon the occurrence of an event of default under the Resolution, the Insurer shall control and direct the enforcement of all rights and remedies granted to the Holders of the Offered Securities or to the Trustee for the benefit of the Holders. See APPENDIX C – "SUMMARY OF CERTAIN PROVISIONS OF THE RESOLUTION AND THE POWER SUPPLY CONTRACTS."

There follows under this caption certain information concerning the Insurer and the Policies which has been supplied by the Insurer. The Insurer has also supplied the specimen of the Policies attached to this Official Statement as APPENDIX G. No representation is made by FMPA, the Underwriters or any of their counsel as to the accuracy, completeness or adequacy of such information, or as to the absence of material adverse changes in such information subsequent to the date hereof. Neither FMPA, the Underwriters or any of their counsel has made any independent investigation of the Insurer or the Policies, and reference should be made to the information set forth below. The Policies do not constitute a part of the contract between FMPA and the holders of the Offered Securities as evidenced by the Offered Securities or the Resolution. Except for payment of the premium for the

FMPA-POD3-00030

HEARING EXHIBIT - 00000440

Policies by FMPA, neither FMPA nor the Underwriters have any responsibility whatsoever with respect to the Policies, including the maintenance or enforcement thereof or collection of amounts payable thereunder.

CIFG Assurance North America, Inc.

The information set forth in the following paragraphs has been provided by CIFG Assurance North America, Inc., referred to in this Official Statement as the Insurer or CIFG, for inclusion in this Official Statement.

General

CIFG Assurance North America, Inc. is a monoline financial guaranty insurance company incorporated under the laws of the State of New York. The address of the principal executive offices of the Insurer is 825 Third Avenue, Sixth Floor, New York, New York 10022; its toll-free telephone number is (866) CIFG-212 and its general telephone number is (212) 909-3939.

The Insurer is a member of the CIFG Group of financial guaranty companies, which also includes CIFG Europe, a French insurance company licensed to do business in the European Union, and CIFG Guaranty, a dedicated French reinsurance corporation. In addition to its capital and surplus as set forth below, the Insurer is supported by a net worth maintenance agreement from CIFG Guaranty, which provides that CIFG Guaranty will maintain the Insurer's New York statutory capital and surplus at no less than $80 million, and may cede a substantial portion (not to exceed 90%) of its exposure on each transaction to CIFG Guaranty through a facultative reinsurance agreement.

Each of the Insurer, CIFG Europe and CIFG Guaranty has received an insurer financial strength rating of "AAA" from Fitch, an insurer financial strength rating of "Aaa" from Moody's, and an insurer financial enhancement rating of "AAA" from Standard and Poor's, the highest rating assigned by each rating agency. Each such rating should be evaluated independently. The ratings reflect the respective rating agency's current assessment of each company's capacity to pay claims on a timely basis and are not recommendations to buy, sell or hold the Offered Securities. Such ratings may be subject to revision or withdrawal at any time.

The Insurer is licensed and subject to regulation as a financial guaranty insurance corporation under the laws of the State of New York, its state of domicile, and is licensed to do business in 46 jurisdictions. The Insurer is subject to Article 69 of the New York Insurance Law which, among other things, limits the business of such insurers to financial guaranty insurance and related lines, requires that such insurers maintain a minimum surplus to policyholders, establishes contingency, loss and unearned premium reserve requirements for such insurers, and limits the size of individual transactions and the volume of transactions that may be underwritten by such insurers. Other provisions of the New York Insurance Law applicable to non-life insurance companies such as the Insurer regulate, among other things, permitted investments, payment of dividends, transactions with affiliates, mergers, consolidations, acquisitions or sales of assets and incurrence of liabilities for borrowings.

Capitalization

The following tables set forth the capitalization of the Insurer on the basis of accounting practices prescribed or permitted by the New York State Insurance Department ("statutory accounting practices").

	Statutory Accounting Practices December 31, 2004 (in thousands of US dollars)
Admitted Assets	$ 152,361
Liabilities	$ 38,733
Capital and Surplus	$ 113,628

FMPA-POD3-00031

HEARING EXHIBIT - 00000441

The following table sets forth the capitalization of CIFG Guaranty on the basis of accounting principles generally accepted in France ("French GAAP").

	French GAAP December 31, 2004	
	(in thousands of euros)	(in thousands of US dollars) (1)
Assets	€ 653,332	$ 891,145
Liabilities	€ 71,763	$ 97,885
Shareholder's Equity	€ 581,569	$ 793,260

(1) The translation of euros to U.S. dollars is presented solely for the convenience of the reader, using the observed exchange rate at December 31, 2004 of $1.364 to €1.00. The convenience translation should not be construed as representation that the euro amounts have been, could have been, or in the future could be, converted into U.S. dollars at this or any rate of exchange.

For further information concerning the Insurer and CIFG Guaranty, see the audited financial statements of both companies, including the respective notes thereto, prepared on the basis of statutory accounting practices in the case of the Insurer and in accordance with French GAAP in the case of CIFG Guaranty, as of December 31, 2004 and 2003 and for each of the three years in the period ended December 31, 2004, which are available on the CIFG Group's website at www.cifg.com. Copies of prior audited annual financial statements of the Insurer and CIFG Guaranty prepared in accordance with statutory accounting practices and French GAAP, respectively, are also available on the website. Copies of all such financial statements may be obtained, without charge, upon request to the Insurer at its address above, Attention: Finance Department.

FLORIDA MUNICIPAL POWER AGENCY

General

FMPA was created on February 24, 1978 in accordance with the provisions of Article VII, Section 10 of the Florida Constitution, the Florida Interlocal Cooperation Act, the Joint Powers Act and the Interlocal Agreement as executed by the then Members of FMPA.

FMPA has authority to plan, finance, acquire, construct, reconstruct, own, lease, operate, maintain, repair, improve, extend or otherwise participate jointly in projects, including projects for the generation and transmission of electricity and to issue bonds or bond anticipation notes for the purpose of financing or refinancing the costs of such projects.

Organization and Management

Each of the 29 Members appoints its board member to the Board of Directors of FMPA (the "Board"). The Board is FMPA's governing body. The Board has the responsibility for developing and approving FMPA's budget, hiring a General Manager and General Counsel and establishing bylaws, which govern how FMPA operates, and policies which implement such bylaws. The Board also authorizes all debt issued by FMPA. The Board elects a Chairman, a Vice-Chairman, a Secretary, a Treasurer and an Executive Committee. The Executive Committee consists of nine members of the Board elected by the Board plus the current Chairman, Vice-Chairman, Secretary and Treasurer of the Board. The officers of the Board also serve in the same positions on the Executive Committee.

The current Chairman, Elie J. "Bud" Boudreaux III, is expected to retire and not seek re-election as Chairman in July 2006. A new Chairman is expected to be elected at the Board's annual meeting in July 2006.

The Executive Committee meets regularly to control FMPA's day-to-day operations and approve expenditures and contracts. The Executive Committee is also responsible for assuring that budgeted expenditure levels are not exceeded and that authorized work is completed in a timely manner.

HEARING EXHIBIT - 00000442

In order to facilitate the Project decision-making process for each Project, there is a Project Committee comprised of one individual designated by each Participant. The Project Committee serves only in an advisory capacity, and all decisions concerning the Project are decided by the Executive Committee or the Board of Directors, as appropriate.

Decisions of the Board of Directors are made pursuant to a weighted voting system, with each Member entitled to a vote that is weighted on the basis of such Member's retail sales to its own customers. A majority of the total weighted votes represented on the Board must be present in order to establish a quorum. Actions of the Board of Directors require approval by a majority of the weighted votes present.

The following is a brief description of the officers of the Board and the Executive Committee, and the principal staff members of FMPA:

Chairman of Board and Executive Committee: ELIE J. "BUD" BOUDREAUX III, P.E.

Mr. Boudreaux has served as Director of Utilities for the Fort Pierce Utilities Authority since 1994. In all, he has 22 years of experience in the utility industry. Prior to joining Fort Pierce, he served as the director for the Utilities Construction and Contract Management Department in Pasco County, Florida for three years, was Owner and Manager of Suncoast Quality Builders, Inc. for four years and served as the chief of operations for Base Civil Engineering at the MacDill Air Force Base for three years. Mr. Boudreaux was elected as FMPA's Chairman in 2003. Previously he served one year as FMPA's Vice Chairman and three years as FMPA's Treasurer. Mr. Boudreaux has been a member of FMPA's Board of Directors since 1994 and a member of the Executive Committee since 1995. Mr. Boudreaux is a registered professional engineer in the state of Florida. He holds a bachelor's degree in mechanical engineering from the University of Southwestern Louisiana and a master's degree in facilities management from the Air Force Institute of Technology.

Vice-Chairman of Board and Executive Committee: VICENTE R. RUANO

Mr. Ruano is the City Manager for the City of Bushnell, Florida, a position he has held since December 1981. Prior to 1981, he spent five years as the Public Works Director for the City of Mascotte, Florida. Mr. Ruano has been a State Certified Operator of Water and Wastewater Plants for over 28 years. Mr. Ruano studied Engineering at the University of Maryland, and also studied Business at the University of Central Florida. Mr. Ruano was elected FMPA's Vice Chairman in 2003. Previously, he served nine years as FMPA's Secretary and four years as FMPA's Assistant Secretary-Treasurer. He has been a member of FMPA's Board of Directors since 1985 and a member of the Executive Committee since 1987. Mr. Ruano is Past President of the Florida Municipal Electric Association.

Secretary of Board and Executive Committee: SUSAN J. FREIDEN

Ms. Freiden is Town Manager of the Town of Havana, Fla., and she serves as the elected Secretary of the Florida Municipal Power Agency. Ms. Freiden has served as Havana's Town Manager since 1994, and previously, she served as Assistant Town Manager for three and a half years. In all, Ms. Freiden has 15 years of experience in the municipal electric utility industry. Prior to joining the Town of Havana, Ms. Freiden worked in commercial real estate for two years. She was first elected as FMPA's Secretary in July 2003. Ms. Freiden has been a member of FMPA's Board of Directors since 1994 and a member of the Executive Committee since 2000. Ms. Freiden is active with the Florida Municipal Electric Association (FMEA). Ms. Freiden served as FMEA's President in 2002-2003. Ms. Freiden holds bachelor's degrees in political science and public administration from the University of Oklahoma.

HEARING EXHIBIT - 00000443

Treasurer of Board and Executive Committee: JAMES C. WELSH, P.E.

Mr. Welsh is President and General Manager (CEO) for the Kissimmee Utility Authority in Kissimmee, Florida, a position he has held since 1982. Mr. Welsh has 33 years of experience in the utility industry. Prior to joining Kissimmee Utility Authority, he served for three years as lead engineer for the East Kentucky Power Cooperative, for one year as senior engineer with R.W. Beck & Associates, and for five years as an engineer with Philadelphia Electric Company. Mr. Welsh is a registered professional engineer in the states of Florida and Pennsylvania and has previously been registered in Colorado and Kentucky. He holds a bachelor's and a master's degree in engineering from the University of Pennsylvania and a master's degree in business administration from Rollins College in Winter Park, Florida. Mr. Welsh was elected as FMPA's Treasurer in 2002. Previously, he served as FMPA Vice Chairman, Secretary-Treasurer and Assistant Secretary-Treasurer. Mr. Welsh has been a member of FMPA's Board of Directors since 1982 and a member of the Executive Committee since 1984.

General Manager and CEO of FMPA: ROGER A. FONTES

Mr. Fontes has over 36 years of experience in the utility industry and joined FMPA in March 2001. Prior to joining FMPA, Mr. Fontes spent 20 years with Northern California Power Agency. He served 13 years as assistant general manager and seven years as engineering manager. Mr. Fontes was previously employed by the California Energy Commission from 1976 to 1981 and was with the Los Angeles Department of Water and Power from 1971 to 1976. Mr. Fontes is co-founder and executive committee member of the Transmission Access Policy Study Group (TAPS). FMPA is a member of TAPS. He is a member and past chair of APPA's Legislative and Resolutions Committee. Mr. Fontes holds a bachelor's degree in mechanical engineering from California State University and a master's degree in environmental engineering from the University of Southern California. Mr. Fontes has been elected to the APPA Board of Directors. Mr. Fontes is President of the Board of Directors of Public Gas Partners; a Georgia non-profit corporation engaged in acquiring natural gas reserves.

General Counsel of FMPA: FREDERICK M. BRYANT, ESQUIRE

Mr. Bryant has over 36 years of experience in the municipal electric industry and has held the position of General Counsel to FMPA since FMPA's creation in 1978. Mr. Bryant received a bachelor's degree in history and political science from Stetson University and his law degree from the University of Florida Law School. Mr. Bryant is a past Chairman of the American Public Power Association Legal Section, and he has authored numerous continuing legal education articles and legal seminar presentations. Mr. Bryant is also General and Regulatory Counsel to the Florida Municipal Electric Association.

Assistant General Manager, CFO and Risk Manager of FMPA: MARK J. LARSON, CPA

Mr. Larson has 23 years of experience in municipal utility finance and has served as Assistant General Manager, CFO and Risk Manager of FMPA since November 2004. Prior to his recent position, he was FMPA's Director of Finance and CFO for two years. Prior to joining FMPA, Mr. Larson was Director of Finance of the Greenville, North Carolina Utilities Commission for more than ten years. Mr. Larson is a member of the North Carolina Association of Certified Public Accountants and the Government Finance Officers Association of U.S. and Canada. Mr. Larson holds a bachelor's degree in business administration and a master of science degree in accounting from North Texas State University, now known as University of North Texas and a Master of Public Administration degree from East Carolina University. He also holds the designation of Certified Public Accountant (CPA) from the state of North Carolina.

FMPA-POD3-00034

HEARING EXHIBIT - 00000444

Assistant General Manager, Power Resources of FMPA: RICHARD L. CASEY

Mr. Casey has 33 years of experience in the electric utility industry. and has served as Assistant General Manager, Power Resources for FMPA since November 2004. Prior to his current position, he was FMPA's Planning and Contracts Manager for 11 years. Prior to joining FMPA, he worked for Texas Utilities for 21 years. While there, he held various engineering positions, including five years as Principal Engineer. He spent seven years with Texas Utility's Interutilities Services, dealing with interconnection, transmission service and power sales agreements. Mr. Casey is actively involved in the Florida Reliability Coordinating Council, one of the 10 regional councils in the North American Electric Reliability Council, where he serves on the Available Transmission Capacity Working Group. He is also a member of the Institute of Electrical and Electronic Engineers. Mr. Casey holds a bachelor's degree in electrical engineering from Lamar University in Beaumont, Texas.

Assistant General Manager, Member Services of FMPA: THOMAS E. REEDY, P.E.

Mr. Reedy has 29 years of experience in the electric utility industry and has held the position of Assistant General Manager, Member Services of FMPA since November 2004. Prior to his recent position, he was FMPA's Director of Member Services for six years. He has been with FMPA since 1995, when he was hired as member services coordinator and subsequently served as member services manager. Prior to joining FMPA, he served four years as an executive consultant for Resource Management International, Inc. His background includes experience in cogeneration development, electric utility planning, electric utility dispatching and operations, forecasting and load research. At FMPA, his responsibilities include all information systems and all aspects of member services, including the Joint Purchase Project, the Energy Services Project and environmental services. Mr. Reedy has a bachelor's degree in electrical engineering from the University of Florida, and is a registered professional engineer in the state of Florida.

THE PROJECT

Introduction

The Participants in the Project are the following 15 Members: Bushnell, Clewiston, Fort Meade, Fort Pierce, Green Cove Springs, Havana, Jacksonville Beach, Key West, Kissimmee, Lake Worth, Leesburg, Newberry. Ocala, Starke and Vero Beach.

FMPA has the responsibility to plan for the Participant's future power supply needs. FMPA is continually evaluating its power supply resource mix, projecting the Project's future power needs, and seeking cost-effective generation additions. See "COMPETITIVE POSITION OF FMPA AND THE PARTICIPANTS."

Project Generating Facilities Owned by FMPA

Stanton Units No. 1 and No. 2. As part of the Project, FMPA owns a 6.5060% undivided ownership in Stanton Unit No. 1 ("Stanton Unit No. 1"), and a 5.1724% undivided ownership interest in Stanton Unit No. 2 ("Stanton Unit No. 2" and, together with Stanton Unit No. 1, the "Stanton Units") at the Stanton Energy Center of the Orlando Utilities Commission ("OUC") located in Orange County, Florida. The Stanton Units were constructed, and are operated by, OUC.

Additional ownership interest by FMPA and other entities in the Stanton Units is described below under "OTHER FMPA PROJECTS."

Stanton Unit No. 1 began commercial operation on July 1, 1987. The availability factor has averaged 86.89% since that time. For the last five fiscal years, the availability factor has ranged from a low of 81.34% in 2005 to a high of 92.61% in 2001.

HEARING EXHIBIT - 00000445

Stanton Unit No. 2 began commercial operation on June 1, 1996. The availability factor has averaged 88.25% since this time. For the past five fiscal years, the availability factor ranged from a low of 83.16% in 2003 to a high of 92.17% in 2001.

Cooling water for the Stanton Units is provided by the Orange County, Florida Eastern Sub-Regional Wastewater Treatment Plant under an agreement between OUC and Orange County.

Coal is supplied to the Stanton Units No. 1 and 2 under contracts between OUC and TECO Coal Corporation ("TECO"), Black Mountain Resources ("Black Mountain"), James River Coal Company ("James River") and Consolidated Energy Company ("Consolidated Energy"). The contract with TECO Coal will supply a base tonnage of 576,000 tons per year through 2011. The contract with Black Mountain Resources will supply a base tonnage of 700,000 tons per year through 2011. The contract with James River is for 670,000 tons of fuel per year through 2009 including 400,000 tons per year of synfuel for 2006 and 2007, 30,000 tons per year of fixed price purchases for 2006 and 2007 and 240,000 tons per year that are priced at market based levels. For 2008 and 2009, the contract provides for market based pricing. Should OUC and James River fail to agree on a market price for the tonnage, the contract may be terminated. The contract with Consolidated Energy is 240,000 tons for 2006 with an option for 2007. Any deficiencies in supply are made up through short-term purchases at spot market prices.

FMPA believes the Stanton Units are well maintained and are in substantial compliance with all material environmental laws and operating permits. FMPA does not expect any out-of-the ordinary costs and expenses for the Stanton Units.

Stanton Unit A. As part of the Project, FMPA owns a 3.5% ownership interest in a 625 MW, gas-fired combined cycle unit located at OUC's Stanton Energy Center site. The remaining ownership interests are held by KUA (3.5%), OUC (28%) and Southern Power Company ("Southern") (65%). Stanton Unit A was placed in service in 2004. For the first ten years of the unit's commercial operation, OUC, KUA and FMPA are also purchasing Southern's ownership share in the unit though purchase power agreements, with FMPA purchasing 10% of Southern's ownership share. The unit also has fuel oil as a back-up capability. Gas transportation is supplied via the Florida Gas Transmission ("FGT") gas line. Under the Capacity and Energy Sales Contract, KUA's interest is treated as a capacity and energy resource of the Project. See "Member Contributed Resources" below.

Cane Island Units No. 1, No. 2 and No. 3. As part of the Project, FMPA owns a 50% undivided ownership interest in each of Cane Island Unit No. 1 ("Cane Island Unit 1"), Cane Island Unit No. 2 ("Cane Island Unit 2") and Cane Island Unit No. 3 ("Cane Island Unit 3" and, together with Cane Island Unit 1, and Cane Island Unit 2, the "Cane Island Units") located at KUA's Cane Island Site in Osceola County, Florida.

The Cane Island Units are natural gas fired electric generating units with No. 2 oil as a back up capability. Cane Island Unit 1 is a combustion turbine, and Cane Island Unit 2 and Cane Island Unit 3 are combined cycle units. All of the Cane Island Units were constructed, and are operated, by KUA. KUA owns the remaining 50% of the Cane Island Units. Cane Island Unit 1 has a maximum rating of 40 MW and was placed in service in January 1995. Cane Island Unit 2 has a maximum rating of 120 MW and was placed in service in June 1995. Cane Island Unit 3 has a maximum rating of 250 MW and was placed in service in June 2002.

Fuel for the Cane Island Units is transported under long-term firm transmission contracts between FMPA and FGT and between KUA and FGT for firm gas transportation. FMPA has committed to natural gas transportation capacity in the amount of 25,000 MMBTU's per day year round. FMPA administers 55,000 MMBTUs of natural gas and 10,000 MMBTU's of discounted gas for the Project's Participants. FMPA also has interconnection agreements with Gulfstream Natural Gas System for additional gas supply to the Cane Island Units.

FMPA is a 50% owner of the transmission lines that connect the Cane Island site to the grid.

FMPA believes the Cane Island Units are well maintained and in substantial compliance with all material environmental laws and operating permits. FMPA does not expect any out-of-the-ordinary costs and expenses for the Cane Island Units.

HEARING EXHIBIT - 00000446

Indian River Units. As part of the Project, FMPA owns a 39% undivided ownership interest in each of the Indian River Combustion Turbine Units A & B ("Indian River Units A & B") and a 21% undivided ownership interest in each of the Indian River Combustion Turbine Units C & D ("Indian River Units C & D" and, together with Indian River Units A & B, the "Indian River Units") located in Brevard County, Florida. All four Indian River Units are used as peaking units.

In addition to FMPA's ownership interest in Indian River Units A & B that is part of the Project, the other co-owners of undivided ownership interests in the Indian River Units A & B are (i) OUC, which owns 48.8% and (ii) KUA, which owns 12.2%.

In addition to FMPA's ownership interest in Indian River Units C & D that is part of the Project, OUC owns the remaining 79% of Indian River Units C & D.

The Indian River Units were constructed, and are operated by, OUC on behalf of the co-owners.

Indian River Units A & B each have a rating of 37 MW and were placed in service on July 1, 1989. Indian River Units C & D each have a nominal rating of 129 MW and were placed in service in October 1, 1992.

The Indian River Units burn either natural gas or No. 2 fuel oil, with gas transportation supplied via FGT.

FMPA believes the Indian River Units are well maintained and in substantial compliance with all material environmental laws and operating permits. FMPA does not expect any out-of-the-ordinary costs and expenses for the Indian River Units.

Key West Units 2 and 3. FMPA constructed two 17.5 MW combustion turbines at the Stock Island Plant near Key West in 1998 to provide peaking supply and on island reliability for the Key West System. The units are refurbished GE Frame 5 units that burn No. 2 oil. The units are expected to have a life of about 25 years.

Purchased Power and Other Contracts

FMPA has a number of contracts (both long and short term) to purchase power and energy from various electric utilities, including OUC, Florida Power & Light ("FPL"), Gainesville Regional Utilities, the City of Lakeland ("Lakeland"), Progress Energy Florida ("PEF"), Calpine Corporation ("Calpine"), Southern and others. FMPA believes that it will be able to replace these resources when their respective contracts expire with new resources under contracts that will be at market based rates.

Calpine. FMPA and Calpine entered into a power sales agreement providing for the supply of 35 MW beginning in May 2005, increasing to 75 MW on January 1, 2006 and increasing to 100 MW on January 1, 2007 and continuing at that level for the remaining three years of the contract. In December 2005, Calpine filed for Chapter 11 bankruptcy protection. Since December 2005, Calpine has generally been performing under the contract. However, FMPA has withheld certain payments to Calpine because delivery of power under the contract has not been totally in compliance with the contract. FMPA expects to continue to work with Calpine to continue the delivery of power under the existing agreement.

Southern. FMPA and Southern executed an agreement in February 2006 pursuant to which FMPA will purchase 157 MW from a new generating unit to be constructed at an existing Southern location. Generation from the unit is expected to be dedicated to FMPA. The unit is expected to begin commercial operation in late 2007.

Lakeland. FMPA has a 100 MW contract with Lakeland, originally scheduled to expire in 2010. The contract has been recently renegotiated so that it will expire in December, 2007.

Member Contributed Resources

Pursuant to their joining the Project, Fort Pierce, KUA, Lake Worth, Key West and Vero Beach have entered into a Capacity and Energy Sales Contract whereby these Participants sell the capacity and energy from their

HEARING EXHIBIT - 00000447

generating units to the Project. Also covered by the contracts is the long term purchase by Key West of 45 MW from FPL's fossil fuel units through 2013. These Participants also sell to the Project any capacity and energy from any Entitlement Shares they have in the Stanton, Stanton II or Tri-City Projects. In addition, Starke has assigned to the All-Requirements Project its capacity and energy in the Stanton and Stanton II Projects. The price paid by the Project to these Participants is equal to each month's billing from FMPA to each of these Participants for their Entitlement Shares in the Projects. In addition, FMPA pays the fuel costs of the Participants under their fuel supply contracts. See "PROJECT PARTICIPANTS— Change in Status of Certain Participants."

Future Power Supply

Stock Island Unit 4. In November 2005, FMPA began construction on a 42 MW low sulfur oil-fired combustion turbine located at the Stock Island Plant near Key West. The unit is scheduled to begin operation in the summer of 2006. Presently, the combustion turbine and auxiliary facilities have been set on foundations and piping, wiring, and other interconnections have begun. First fire is scheduled for May, 2006. Stock Island Unit 4 will be operated by the Utility Board of the City of Key West and is expected to be 20% more efficient than other units that serve a similar "peaking" function. FMPA has authorized $33.0 million to design and construct the plant.

Treasure Coast Energy Center Unit 1. FMPA has received Florida Public Service Commission ("PSC") certificate of need for a 300 MW natural gas-fired combined cycle unit scheduled to begin operation in 2008. The completed site certification from the State Siting Review Board is scheduled for May 7, 2006. Construction of the unit is expected to begin in August, 2006. The unit will be built at a 69-acre plant site southwest of Fort Pierce, selected for its proximity to several FMPA cities and its favorable position on the transmission grid. Construction contracts have been awarded to The Industrial Company and to Utility Engineers, and the purchase order for the combustion turbine and the steam turbine generators has been awarded to General Electric. The plant will be wholly owned by FMPA, but operated under contract by Fort Pierce Utilities Authority (FPUA).

Taylor Energy Center. FMPA, together with JEA, Reedy Creek Improvement District and the City of Tallahassee have identified a 3,300-acre site in Taylor County, Florida to construct an 800 megawatt coal-fired power plant. Purchase of the site is currently being negotiated and development of the site is contingent upon a change in the local land use designation for the site as well as permitting and licensing requirements. The proposed 800 megawatt unit is expected to cost $1.6 billion and FMPA is expected to receive approximately 300 MW of the plant's output.

Fuel Supply

Coal Supply. For a description of the coal supply to All-Requirements generating facilities, see "Project Generating Facilities Owned by FMPA" above.

Gas Supply. Natural gas for Stanton Unit A is obtained by OUC for itself, KUA and FMPA. All physical supplies of natural gas used at FMPA-owned or Participant-owned generating facilities are purchased by Florida Gas Utility ("FGU") for FMPA under a long term service agreement between FMPA and FGU. Typically these supplies are purchased on a month-to-month basis and are priced at a NYMEX plus basis differential into the Florida Gas Transmission ("FGT") system. FGU also handles all natural gas transportation related functions for FMPA and all of FMPA's Members.

Oil Supply. All physical fuel oil purchases are handled by the individual owners of the generation. Purchases of fuel oil (with the exception of Key West, where fuel oil is the only fuel used) are typically only made to maintain back-up inventories at a level consistent with FMPA's fuel management policies. The purchases are made on a spot basis and at the then effective market price.

Public Gas Partners, Inc. On November 16, 2004, FMPA signed an agreement with six other public gas and electric utilities in five different states to form a gas supply agency called Public Gas Partners, Inc. ("PGP"). PGP is formed under Georgia law as a not-for-profit corporation and is tax-exempt for federal tax purposes. PGP was created to secure economical, long-term wholesale natural gas supplies for its seven members in order to stabilize and reduce the cost of natural gas. The members of PGP, along with FMPA, include Municipal Gas

FMPA-POD3-00038

HEARING EXHIBIT - 00000448

Authority of Georgia, Florida Gas Utility, Lower Alabama Gas District, Patriots Energy Group, Southeast Alabama Gas District and Tennessee Energy Acquisition Corporation.

PGP's acquisition activities are organized by gas supply pools, with PGP entering into production sharing agreement contracts with members that elect to participate in the various pools. Each supply pool stands alone with rights and obligations separate from other pools. FMPA, by joining PGP, has pledged to pay its share of all common costs and 100% of any costs incurred by PGP on FMPA's behalf. By contract FMPA also has accepted a step-up provision which would require a maximum additional exposure of 25% of its original nominated amount. No rights exist to withdraw unless financial obligations to PGP are extinguished or assumed by another PGP member.

PGP Gas Supply Pool No. 1 ("PGP Pool No. 1") was formed by all of the participants as the vehicle for securing the long-term natural gas supplies. PGP Pool No. 1 targeted an initial supply portfolio capable of producing 60,000 MMBTU per day of natural gas or 219 billion cubic feet over a ten year period. FMPA has nominated 15,000 mmBtu/day, which represents approximately 15% of its projected gas needs by 2010.

On October 1, 2005, FMPA signed agreements to participate in PGP Gas Supply Pool No. 2 ("PGP Pool No. 2"). This pool was formed to participate in specific transactions that have different acquisition criteria from PGP Pool No. 1. PGP Pool No. 2 has a total acquisition expenditure limit of $200 million with FMPA's share being $50.0 million as authorized by the Board (before step-up provisions which would increase FMPA's commitment to a maximum of $62.5 million).

Acquisition activity has occurred in Pool No. 2, with initial reserve acquisition financing done through PGP's interim financing capabilities, with the member of each pool determining when the financing is to be used. The Offered Securities and Series 2006A Bonds include funding for FMPA's share of acquisitions completed or anticipated to be completed over the next two years.

At PGP's first governing board meeting on November 2004, the PGP Board of Directors (the "PGP Board") elected Roger Fontes, FMPA's General Manager, as Chairman of the PGP Board, James H. Smith of Southeast Alabama Gas District as Vice Chairman, and Katrina Vaughan of FGU as Secretary/Treasurer. The PGP Board also appointed Susan Reeves, Chief Financial Officer of the Municipal Gas Authority of Georgia, as President of PGP. PGP entered into a service contract with the Municipal Gas Authority of Georgia to act as the corporation's manager.

Transmission and Dispatch Agreements

Transmission. OUC provides transmission service for delivery of power and energy from FMPA's ownership in Stanton Unit No. 1, Stanton Unit No. 2, Stanton Unit A and the Indian River Units for the Project to the FPL and PEF interconnections with OUC for subsequent delivery to the Participants over the life of the Units. Rates for such transmission wheeling service are based upon OUC's costs of providing such transmission wheeling service and under terms and conditions of the OUC-FMPA firm transmission service contracts for the Project.

FMPA has contracts with PEF, FPL and OUC to transmit the various Project resources over the transmission systems of each of these three utilities. The Network Service Agreement with FPL was executed in March 1996 and was subsequently amended to both conform with FERC's Proforma Tariff and to add additional members to the Project. The FPL agreement provides for network transmission service for the Project Participants located in FPL's service territory. To provide transmission wheeling service for Project Participants located in PEF's service territory, FMPA operates under an existing agreement with PEF which was executed in April 1985 and which also provides for network type transmission service as does the FPL agreement. PEF gave notice in December 2004 that the existing agreement will terminate as of December 31, 2010, after which FMPA will be subject to PEF's Proforma Tariff. FMPA also has several transmission wheeling agreements with OUC which are associated with each FMPA generation resource located on OUC's system and which also provide for network type transmission service over OUC's system.

Dispatch. To provide Project capacity and energy to the Participants, FMPA has contracted with OUC for the dispatch of FMPA's generation resources to serve the loads of the Participants on a continuous real-time basis under the Contract for Dispatching Service for FMPA by OUC (the "Dispatch Contract"). The Participant delivery points are effectively removed from the control areas of PEF and FPL and scheduled power deliveries to the Participants are transmitted to the delivery points over the PEF or FPL systems. Regulation of the scheduled deliveries is accomplished by effectively placing the Participants into the OUC control area. In order to integrate the Participants into the OUC control area, each delivery point is equipped by FMPA with a Remote Terminal Unit to collect and transmit necessary real-time load data to the OUC automatic generation control system.

The Dispatch Contract provides for (i) OUC to dispatch FMPA's resources to serve the combined loads of the Participants located in PEF's service territory and the Participants located in FPL's service territory; (ii) FMPA installing and maintaining the necessary equipment on the Participants' systems; (iii) OUC installing and maintaining the necessary equipment on its system; and (iv) pricing and payments for services provided. The term of the Dispatch Contract and all obligations to make payments under the Dispatch Contract commenced upon signing of the Dispatch Contract and will continue in effect for a period of twenty five (25) full calendar years after the All-Requirements Project Services Commencement Date (May 1, 1986).

Florida Municipal Power Pool

The Project is a member of the Florida Municipal Power Pool ("FMPP"). The other members of FMPP are Lakeland and OUC. The FMPP is an operating power pool in which the generating resources of members are centrally dispatched to meet their load requirements. The FMPP began operations in 1988. FMPP resources include the members' coal fired generation, gas/oil fired units, ownership interest in nuclear capacity, and various firm capacity and partial requirements arrangements with other utilities. Each FMPP member is responsible for maintaining sufficient capacity to serve its own load including an adequate amount of reserves. The resources of FMPP are essentially committed and dispatched by OUC, which handles the day-to-day operations of the FMPP.

The Project's membership in the FMPP provides several benefits for the Project. By participating in the FMPP, the Project is able to realize significant savings due to the fact that FMPA is able to utilize more efficient, less costly generation than FMPA could have utilized if the Project were not a member of the pool. A pool marketing group that buys or sells capacity and energy on a daily basis has improved profitability for the Project through the successful sale or purchase of capacity and energy. FMPA is additionally considering "pooling" fuel resources with the possibility of saving more dollars on fuel procurement collectively than could have been saved separately.

Future Capital Requirements

The acquisition and construction of the Taylor Energy Center described above under "Future Power Supply" could result in capital expenditures of approximately $575 million for the Project over the next 6 years. These expenditures could be financed with Additional Bonds or through the Pooled Loan Project discussed under "OTHER FMPA PROJECTS – Pooled Loan Project." In addition FMPA is evaluating other possible additions to the Project which would require capital expenditures.

Project Operations

For the fiscal year that ended on September 30, 2005, the non-coincident peak demand on the Project was 1,527 MW. This peak demand was an 8% increase compared to the 2004 fiscal year.

For the 2005 fiscal year, the Project produced 6.543 million MWh of billable energy, a 3% increase from the 2004 fiscal year.

Sales to the Participants in fiscal year 2005 were $446.4 million, a 12% increase compared to the 2004 fiscal year. This increase was due primarily to fuel price increases and load growth.

For the 2005 fiscal year, Project power costs were 72.57 cents per kWh, a 14% increase compared to the 2004 fiscal year. This increase was primarily due to higher fuel costs.

HEARING EXHIBIT - 00000450

Historical and Estimated Future Capacity Requirements and Resources

The historical and estimated future Project capacity requirements and resources are summarized in the following table.

THE PROJECT
HISTORICAL AND ESTIMATED FUTURE CAPACITY REQUIREMENTS AND RESOURCES

	Actual					Estimated				
Project Requirements (MW)	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Coincident Peak Demand (1)	965	992	1,340	1,416	1,524	1,534	1,570	1,600	1643	1532
Load Management (2)	(4)	(4)	(12)	0	0	0	0	0	0	0
Total Requirements(MW)	961	988	1,328	1,416	1,524	1,534	1,570	1,600	1,643	1,503 (8)
Project Resources (MW)										
Excluded Resources (3)	54	54	85	85	85	84	83	83	83	72
Stanton Unit 1	83	83	122	122	122	123	123	123	123	103
Stanton Unit 2	67	67	98	98	98	101	101	101	101	84
Cane Island Unit 1	15	15	15	15	15	17	17	17	17	17
Cane Island Unit 2	54	54	54	54	54	54	54	54	54	54
Cane Island Unit 3	80	120	120	120	120	123	123	123	123	123
Indian River Units A & B	29	29	37	37	37	37	37	37	37	37
Indian River Units C & D	44	44	44	44	44	45	45	45	45	45
Key West Unit 2&3	35	35	35	35	35	31	31	31	31	31
Key West Unit 4 (4)	0	0	0	0	0	42	42	42	42	42
Treasure Coast Energy Center Unit 1(4)	0	0	0	0	0	0	0	296	296	296
PEF Partial Requirements (5)	40	27	40	20	30	40	30	30	60	40
Indian River Purchase	130	108	87	65	43	22	0	0	0	0
[illegible]nesville Purchase	43	43	3	3	3	3	0	0	0	0
[illegible]C System Purchase	20	20	40	0	0	0	0	0	0	0
Lake Worth Purchase	10	0	0	0	0	0	0	0	0	0
Lakeland	100	100	100	100	100	100	100	0	0	0
FPL Purchase	0	75	75	75	75	75	75	0	0	0
Key West LT FPL	45	45	45	45	45	45	45	45	45	45
Vero Beach Native Generation (6)	150	150	150	150	150	137	137	137	137	0
Ft. Pierce Native Generation (6)	118	118	118	118	118	110	110	0	0	0
Key West Native Generation(6)	50	50	50	50	50	41	41	41	41	41
Kissimmee(5)	210	250	250	250	250	222	222	222	222	222
Lake Worth Native Generation (6)	0	0	86	86	86	87	87	87	87	87
Stanton A	0	0	0	127	127	122	122	122	122	122
Calpine Purchase(6)	0	0	0	0	35	75	100	100	100	0
Southern Power Co Purchase(4)(6)	0	0	0	0	0	0	0	157	157	157
Future New Capacity	0	0	0	0	0	0	0	0	0	84
Total Resources (MW)	1,377	1,487	1,654	1,699	1,722	1,736	1,725	1,893	1,923	1,702
Total Project Reserve Percentage(7)	22.4	28.1	28.5	22.9	14.6	12.8	20.2	15.8	15.8	15.8

(1) Peak demands are at the delivery point level (summer season).
(2) Reductions in peak demand were due to the implementation of a Load Management Program at the cities of Leesburg and Ocala, and Kissimmee. These programs have since been abandoned.
(3) Excluded Power Supply Resources consist of entitlement shares in the St. Lucie Project and ownership shares in Crystal River No. 3.
(4) Currently under construction.
(5) Seller provides reserves for these purchases above the amount shown.
(6) Capacity and Energy purchase.
(7) Total project reserve capacity is based on FMPA's reserve capacity and reserves supplied with Partial Requirements.
(8) The decrease in Total Requirements in 2010 reflects the termination of Vero Beach's obligation to purchase power from the Project. See "PROJECT PARTICIPANTS— Change in Status of Certain Participants."

(Numbers may not add due to rounding.)

Current supply side resources for the Project are classified into five main areas: nuclear capacity, owned generation, member generation, capacity solely owned by FMPA for the Project and purchased power.

FMPA-POD3-00041

HEARING EXHIBIT - 00000451

Nuclear Capacity. A number of Participants own small amounts of capacity in PEF's Crystal River Unit 3. Likewise, a number of Participant's participate in the St. Lucie Project, providing them capacity and energy from St. Lucie Unit No. 2. Capacity from these two nuclear units is classified as "excluded resources" in the Project. As such, the Project members pay their own costs associated with the nuclear units and receive the benefits of the capacity and energy from these units. The Project provides the balance of capacity and energy requirements for the members with participation in these nuclear units. The nuclear units are, however, considered in the capacity planning for the Project.

Owned Generation. This category includes generation that is solely or jointly owned by the Project as well as Participant participation in the Stanton, Tri-City, and Stanton II projects.

Member Generation. Capacity included in this category is generation owned by the Participants either solely or jointly. The Project purchases this capacity from the Participants and then commits and dispatches the generation to meet the total requirements of the Project.

Capacity Solely Owned by FMPA for the Project. This capacity consists of Stock Island Combustion Turbine Units 2 and 3.

Purchased Power. This includes power purchased directly by the Project as well as existing purchase power contracts of individual Participants, which were entered into prior to such Member joining the Project.

FMPA-POD3-00042

HEARING EXHIBIT - 00000452

HISTORICAL OPERATING RESULTS
FOR
THE PROJECT

(Dollars in Thousands)

	Fiscal Year Ending September 30,		
REVENUES:	2003	2004	2005
Participant Payments	$369,166	$401,561	$446,433
Interest Income(1)	1,176	1,197	2,322
Due from Participants(2)	17,419	5,644	28,361
Sales to Others(3)	-	-	33,851
Total Revenues	$387,761	$408,402	$510,967
OPERATING EXPENSES:			
Fixed O and M (4)	$ 34,651	$ 41,457	$ 38,075
Fuel Costs	142,520	132,925	178,227
Purchased Power	164,552	189,925	243,497
General Administrative and Other(5)	9,667	10,062	11,011
Transmission(6)	18,908	21,428	20,832
Total Operating Expenses	$370,298	$394,905	$491,642
NET INCOME	$17,463	$13,497	$19,325
Debt Service(7)	12,111	11,289	14,009
Net Available for Other Purposes	$5,352	$2,208	$5,316
Transfer to:			
Renewal and Replacement Account(8)	$3,681	$1,112	$3,896
Net Sales to Participants (GWh)	6,374	6,378	6,542
Net Power Costs to Participants (Mills/Kwh)	60.5	63.5	72.6

(1) Investment earnings on balances of all funds.
(2) Accounts receivable from Participants due to under recoveries.
(3) Sales to Others in years prior to 2005 were included in Participant Payments.
(4) FMPA's share of operation and maintenance expenses, excluding fuel, allocated to the Project.
(5) Administrative and general expenses for OUC, KUA, FMPA and Southern Company allocated to the Project.
(6) Includes transmission charges over the transmission systems of FPL, Progress Energy and OUC.
(7) Accruals pay principal and interest on the Bonds and any other indebtedness.
(8) Amounts to be charged to Participants for the cost of capital assets.

(Numbers may not add due to rounding)

FMPA-POD3-00043

HEARING EXHIBIT - 00000453

THE PROJECT PARTICIPANTS

Description of the Participants

The fifteen Participants in the Project are twelve Florida municipal corporations, a utility board and two utility authorities. Among the economic factors important to the Participants are agriculture, tourism, retirement and light manufacturing. Each Participant owns and operates a retail electric distribution system. During the calendar year ended December 31, 2005, these systems sold in the aggregate approximately 7,220 GWh of electric services (including sales to other electric utilities), served approximately 270,000 customers, and incurred a coincident peak demand of approximately 1,542 MW.

As set forth in Appendix A hereto, the Participants in the Project are also participants in various other projects of FMPA. See "OTHER FMPA PROJECTS."

Change in Status of Certain Participants

Vero Beach. In March, 2004, Vero Beach requested arbitration against FMPA pursuant to the Capacity and Energy Sales Contract between FMPA and Vero Beach. Vero Beach asserted that FMPA had underpaid Vero Beach for its generation resources for fiscal year 2004 by approximately $7.9 million. In August, 2004, Vero Beach requested arbitration for fiscal years 2005 and 2006, asserting that FMPA underpaid Vero Beach for generation resources for fiscal year 2005 by approximately $6.7 million and will underpay Vero Beach for generation resources for fiscal year 2006 by approximately $8.0 million. In October 2005, the panel of arbitrators decided all contested issues relating to fiscal year 2004 in the arbitration in favor of FMPA and directed that certain of FMPA's costs be paid by Vero Beach. Vero Beach has announced that it will withdraw its request for arbitration with respect to fiscal years 2005 and 2006.

In December 2004, Vero Beach gave notice that it was exercising its contractual right to reduce its obligation to purchase electric power and energy to a contract rate of delivery as defined in the Power Sales Contract. Beginning in 2010 and continuing for the term of the Power Sales Contract, the Project will serve Vero Beach with a load to be calculated in December 2009 (currently estimated to be approximately 33 MW). At the time of such withdrawal, Vero Beach will no longer sell capacity and energy to the Project under its Capacity and Energy Sales Contract.

Starke and Green Cove Springs. The City of Starke and the City of Green Cove Springs have each given FMPA notice pursuant to their Power Supply Project Contracts that the term of their respective contracts will not renew automatically each year after the current contract term. The terms of their respective contracts are now fixed. Starke's contract terminates on October 1, 2036 and Green Cove Springs' contract terminates on October 1, 2037.

FMPA-POD3-00044

HEARING EXHIBIT - 00000454

Major Participants' Historical Net Energy Requirements and Peak Demand

The following table summarizes the historical net energy requirements and aggregate non-coincident peak demand of the five Major Participants.

MAJOR PARTICIPANTS
HISTORICAL NET ENERGY REQUIREMENTS AND PEAK DEMAND
By Fiscal Year
(ending September 30)

Net Energy Requirements (GWh)
(for native load)

Fiscal Year	Jacksonville Beach	Key West	KUA	Ocala	Vero Beach*
2001	743.7	720.6	1,174.4	1,287.6	716.5
2002	750.9	757.5	1,219.2	1,304.5	742.4
2003	777.9	797.3	1,284.1	1,362.8	772.0
2004	786.9	784.9	1,300.3	1,373.5	758.6
2005	804.3	781.4	1,395.2	1,397.0	772.7

*See "PROJECT PARTICIPANTS— Change in Status of Certain Participants."

Peak Demand (MW)

Fiscal Year	Jacksonville Beach	Key West	KUA	Ocala	Vero Beach*
2001	186	129	252	267	176
2002	189	134	262	289	178
2003	227	140	275	286	203
2004	180	141	302	287	163
2005	192	145	346	308	174

*See "PROJECT PARTICIPANTS— Change in Status of Certain Participants."

Major Participants

Appendix B contains certain information about the Major Participants.

OTHER FMPA PROJECTS

Introduction

In addition to the Project, FMPA has four other power supply projects ("Other Projects") in which various Members (including some or all of the Participants) participate — Stanton Project, Stanton II Project, St. Lucie Project and Tri-City Project. FMPA also operates a Pooled Loan Project. (See "Pooled Loan Project" below.)

Each Other Project has been financed by FMPA through senior, and in some cases, subordinated, debt. All debt for a particular Other Project has been issued under various resolutions of FMPA that are applicable only to that Other Project. All debt incurred for a particular Other Project is secured only by the revenues of that Project.

FMPA-POD3-00045

HEARING EXHIBIT - 00000455

Therefore, the revenues of a particular Other Project are not security for the FMPA debt issued for the Project or for any other Other Project.

In the case of the Stanton, Stanton II, St. Lucie and Tri-City Projects Power Sales Contracts and Project Support Contracts, the obligation of a Participant for its share of the costs of an Other Project under the Power Sales Contract for that Other Project is payable solely from the Participant's electric or integrated utility system revenues and are operating expenses of such system, payable on a parity with the system's operation and maintenance expenses and before debt service on the system's senior and subordinated debt. Payment by a Participant of its share of the costs of an Other Project under the Project Support Contract for this Other Project will be made only after payment of all of its system's current operating and maintenance expenses and debt service on the system's senior and subordinated debt.

The following is a brief description of each of the Other Projects. Appendix A gives each Member's participation in any FMPA Project.

Stanton Project

The Stanton Project consists of a 14.8% undivided ownership interest of FMPA in the Stanton Unit No. 1, a coal-fired electric generating unit with a normal high dispatch limit of 425 MW ("Stanton Unit No. 1"). Stanton Unit No. 1 is one of the two-unit coal fired electric generators at the Stanton Energy Center. Stanton Unit No. 1 was constructed, and is operated, by OUC. Power from the Stanton Project is transmitted to the Stanton Participants utilizing the transmission systems of OUC and FPL under the respective contracts with each system. The FPL transmission for the Stanton Project Participants that also participate in the All-Requirements Project (Starke, Fort Pierce, Lake Worth and Vero Beach) is included in the All-Requirements Project Network Transmission Service Agreement with FPL which terminates in 2026. The remaining Stanton Project Participant in FPL's territory (Homestead) receives its transmission service under the Transmission Service Agreement between FMPA and FPL which terminates upon the earlier of retirement of Stanton Unit No. 1 or December 31, 2026. The agreement with OUC expires on the earlier of retirement of Stanton Unit No. 1 or June 2027.

In addition to the ownership of FMPA in Stanton Unit No. 1 representing FMPA's Stanton Project, the other co-owners of undivided ownership interests in Stanton Unit No. 1 are (i) OUC, which owns 68.6%, (ii) FMPA, which owns 5.3% as part of the Tri-City Project discussed below, (iii) FMPA, which owns 6.5% as part of the All-Requirements Project discussed below and (iv) the Kissimmee Utility Authority, which owns 4.8%.

As of March 1, 2006, FMPA had $72,765,000 of senior bonds and $8,472,000 of subordinated debt issued for the Stanton Project, the final maturity of which is 2019.

All debt of FMPA issued for the Stanton Project is payable from amounts payable by the participants in the Stanton Project under power sales contracts and project support contracts of the type described above. Each participant in the Stanton Project is responsible under its power sales contract and project support contract for the costs of the Stanton Project in the amount of its participation share in the Stanton Project as shown on Appendix A.

Stanton Unit No. 1 began commercial operation on July 1, 1987. The availability factor has averaged 86.89% since that time. For the last five fiscal years, the availability factor has ranged from a low of 81.34% in 2005 to a high of 92.61% in 2001. For the last five fiscal years, Stanton Project power costs to its participants have ranged from approximately 3.89 to 5.06 cents per kwh, and were 5.06 cents per kwh for 2005.

FMPA believes the Stanton Project is well maintained and is in substantial compliance with all material environmental laws and operating permits. FMPA does not expect any out-of-the ordinary costs and expenses for the Stanton Project.

Other than the bonds issued with respect to any refunding relating to the Stanton Project, FMPA has no present intention to issue any additional debt for the Stanton Project. To the extent that additional funds are needed for capital expenditures for the Stanton Project, FMPA expects that it would borrow them from the Pooled Loan Project on a subordinated basis.

FMPA-POD3-00046

HEARING EXHIBIT - 00000456

Stanton II Project

The Stanton II Project consists of a 23.2% undivided ownership interest of FMPA in the Stanton Energy Unit No. 2, a coal-fired electric generating unit with a normal high dispatch limit of 429 MW ("Stanton Unit No. 2"). Stanton Unit No. 2 is the second of the two-unit coal fired electric generators at the Stanton Energy Center of OUC. Stanton Unit No. 2 was constructed, and is operated by, OUC. Power from the Stanton II Project is transmitted to the participants utilizing the transmission systems of OUC and FPL under the respective contracts with each system. The FPL transmission for the Stanton II Project Participants that also participate in the All-Requirements Project (Starke, Fort Pierce, Vero Beach, KUA and Key West) is included in the All-Requirements Project Network Transmission Service Agreement with FPL which terminates in 2026. The remaining Stanton II Project Participant in FPL's territory (Homestead) receives its transmission service under the Transmission Service Agreement between FMPA and FPL which terminates upon the earlier of retirement of Stanton Unit No. 2 or December 31, 2032. The agreement with OUC expires on the earlier of retirement of Stanton Unit No. 2 or June 2036.

In addition to the ownership of FMPA in Stanton Unit No. 2 representing FMPA's Stanton II Project, the other co-owners of undivided ownership interests in Stanton Unit No. 2 are (i) OUC, which owns 71.6%, and (ii) FMPA, which also owns 5.2% as part of the Project.

As of March 1, 2006, FMPA had outstanding $191,750,000 of senior bonds and approximately $3,674,000 of subordinated debt for the Stanton II Project, the final maturity of which is October 1, 2027.

All debt of FMPA issued for the Stanton II Project is payable from amounts payable by the participants in the Stanton II Project under power sales contracts and project support contracts of the type described above. Each participant in the Stanton II Project is responsible under its power sales contract and project support contract for the costs of the Stanton II Project in the amount of its participation share in the Stanton Project as shown on APPENDIX A.

Stanton Unit No. 2 began commercial operation on June 1, 1996. The availability factor has averaged 88.25% since this time. For the last five fiscal years, the availability factor has ranged from a low of 83.16% in 2003 to a high of 92.17% in 2001. For the last five fiscal years, Stanton II Project power costs to its participants have ranged from approximately 4.08 to 4.76 cents per kwh, and were 4.76 cents per kwh for 2005.

FMPA believes the Stanton II Project is well maintained and is in substantial compliance with all material environmental laws and operating permits. FMPA does not expect any out-of-the ordinary costs and expenses for the Stanton II Project.

Other than the bonds issued with respect to any refunding relating to the Stanton II Project, FMPA has no present intention to issue any additional debt for the Stanton II Project. To the extent that additional funds were needed for capital expenditures for the Stanton II Project, FMPA expects that it would borrow them from the Pooled Loan Project on a subordinated basis.

St. Lucie Project

The St. Lucie Project consists of a 8.8% undivided ownership interest of FMPA in St. Lucie Unit No. 2, a pressurized water nuclear generating unit with a summer seasonal net capacity of approximately 838 MW ("St. Lucie Unit No. 2"). St. Lucie Unit No. 2 is part of FPL's two-unit nuclear generating station located in St. Lucie County, Florida. St. Lucie Unit No. 2 was constructed and is operated by FPL.

In addition to St. Lucie Unit No. 2, FPL also owns and operates, as part of the St. Lucie nuclear generating station, the St. Lucie Unit No. 1 pressurized water nuclear electric generating unit which has a summer net capacity of 821 MW. St. Lucie Units No. 1 and 2 are similar units.

The St. Lucie Project also consists of a Reliability Exchange between FMPA and FPL under which FMPA exchanges with FPL 50% of its share of the output from St. Lucie Unit No. 2 for a like amount from St. Lucie Unit

HEARING EXHIBIT - 00000457

No. 1 in order to provide output when St. Lucie Unit No. 2 is out of service. The result of this exchange is that if St. Lucie Unit No. 2 is out of service, FMPA obtains 50% of its entitlement from St. Lucie Unit No. 1 and if St. Lucie Unit No. 1 is out of service 50% of FMPA's entitlement from St. Lucie Unit No. 2 is provided to FPL.

FMPA has contracts with both FPL and OUC to transmit power and energy from St. Lucie Units No. 1 and 2 to the participants in the St. Lucie Project. The transmission contract with FPL expires on retirement of St. Lucie Units No. 1 and 2 which is currently expected to be no earlier than 2023. The transmission contract with OUC ends in 2023 or such earlier time as FMPA is no longer entitled to receive output from the St. Lucie Project.

In addition to the ownership of FMPA in St. Lucie Unit No. 2 representing FMPA's St. Lucie Project, the other co-owners of undivided ownership interests in St. Lucie Unit No. 2 are (i) FPL, which owns 85.1% and (ii) OUC, which owns 6.1%.

As of March 1, 2006, FMPA had outstanding $262,000,000 of senior bonds for the St. Lucie Project, the final maturity of which is October 1, 2021.

All debt of FMPA issued for the St. Lucie Project is payable from amounts payable by the participants in the St. Lucie Project under power sales contracts and project support contracts of the type described above. Each participant in the St. Lucie Project is responsible under its power sales contract and project support contract for the costs of the St. Lucie Project in the amount of its participation share in the St. Lucie Project as shown in APPENDIX A.

St. Lucie Unit No. 2 began commercial operation in August, 1983. The capacity factor has averaged 84.3% since that time. For the last five fiscal years, the capacity factor has ranged from a low of 81.7%, in 2002, to a high of 98.9% in 2001. For the last five fiscal years, St. Lucie Project power costs to its participants have ranged from approximately 5.66 cents to 6.42 cents per kwh, and were 6.07 cents per kwh for 2005.

FPL is responsible for obtaining the fuel for both St. Lucie Units No. 2 and No. 1.

FPL has on-site storage sufficient to store spent fuel assemblies for both St. Lucie Unit No. 2 and St. Lucie Unit No. 1 through 2008 and 2012, respectively. FPL is evaluating various options to solve the spent fuel storage issue, such as a rerack of St. Lucie Unit No. 2, and dry cask storage.

The Nuclear Regulatory Commission ("NRC") has granted 20-year operating license renewals for St. Lucie Unit No. 1 and St. Lucie Unit No. 2. The term of the operating licenses for St. Lucie Unit No. 1 and St. Lucie Unit No, 2 previously had been set to expire in 2016 and 2023, respectively. Under the extended terms, the operating licenses for St. Lucie Unit No. 1 and St. Lucie Unit No. 2 will expire in 2036 and 2043, respectively. The NRC has granted a license extension on St. Lucie Unit No. 2. When FPL elects to exercise the license extension, FMPA may issue bonds to finance its portion of the costs associated with the extension.

FMPA believes the St. Lucie Units No. 1 and 2 are well maintained and are in substantial compliance with all material environmental laws and operating permits. FPL replaced the reactor vessel head for St. Lucie Unit No. 1 in 2005 and previously replaced the steam generators. FPL is planning to replace the reactor vessel head and the steam generators for St. Lucie Unit No. 2 in 2007. The cost to FMPA Members of the St. Lucie Project Unit No. 2 is anticipated to be $28 million.

Tri-City Project

The Tri-City Project consists of a 5.3% undivided ownership interest of FMPA in Stanton Unit No. 1. FMPA has contracts with both OUC and FPL to transmit the power and energy from Stanton Unit No. 1 to the participants in the Tri-City Project. See "OTHER FMPA PROJECTS – Stanton Project" above for a further discussion of Stanton Unit No. 1.

FMPA-POD3-00048

HEARING EXHIBIT - 00000458

As of March 1, 2006, FMPA had outstanding $34,935,000 of senior bonds for the Tri-City Project, the final maturity of which is October 1, 2019. As of March 1 , 2006, FMPA also had outstanding $839,000 of subordinated debt issued for the Tri-City Project.

All debt of FMPA issued for the Tri-City Project is payable from amounts payable by the participants in the Tri-City Project under power sales contracts and project support contracts of the type described above. Each participant in the Tri-City Project is responsible under its power sales contract and project support contract for the costs of the Tri-City Project in the amount of its participation share in the Tri-City Project as shown on APPENDIX A.

For the last five fiscal years, Tri-City Project power costs to its participants have ranged from approximately 4.72 cents to 5.66 cents per kwh, and was 5.66 cents per kwh for 2005.

To the extent Funds are needed for capital expenditures for the Tri-City Project, FMPA expects that it would borrow them from the Pooled Loan Project on a subordinated basis.

FMPA believes the Tri-City Project is well maintained and is in substantial compliance with all material environmental laws and operating permits. FMPA does not expect any out-of-the ordinary costs and expenses for the Tri-City Project.

Future Power Supply and Operations

In the future, FMPA may pursue additional power supply alternatives which, if shown to be economically feasible, will be made available to the membership. Power supply alternatives are examined by FMPA to determine if the resource can be competitive with other resources available to the members or if there is some unique feature which justifies further study. A detailed engineering feasibility study is made for those projects which pass this initial screening process. Upon completion of that detailed study, the project is offered to those members of FMPA not participating in the All-Requirements Power Supply Project, who make individual participation decisions, and/or to the All-Requirements Power Supply Project where a decision to participate is made by a majority of the All-Requirements Project members.

Pooled Loan Project

FMPA established the Pooled Loan Project as a vehicle for the financing and refinancing of eligible utility-related projects by its Members. Each Member of FMPA, FMPA itself and FMPA as agent for any of its other projects are eligible to participate in the Pooled Loan Project. FMPA issues commercial paper based on signed loan agreements. Although the Pooled Loan Project was designed with flexibility in mind, its structure does not sacrifice security. Each participant in the pool is separately liable, so the participants bear no financial obligation if another borrower defaults. The Pooled Loan Project has a letter of credit from Wachovia which supports the debt issued to fund Participant loans.

STATE REGULATION

In general, the rates of municipal electric utilities in Florida, including the Participants, are established by the governing bodies of such utilities. Under Chapter 366, Florida Statutes, the PSC has jurisdiction over municipal electric utilities to prescribe uniform systems and classifications of accounts, to require electric power conservation and reliability, to regulate electric impact fees, to establish rules and regulations regarding cogeneration, to approve territorial agreements, to resolve territorial disputes, to prescribe rate structures and to prescribe and require the periodic filing of reports and other data. Pursuant to the rules of the PSC, rate structure is defined as "... the classification system used in justifying different rates and, more specifically...the rate relationship between various customer classes, as well as the rate relationship between members of a customer class." However, the PSC and the Florida Supreme Court have determined that, except as to rate structure, the PSC does not have jurisdiction over municipal electric utility rates, including those of the Participants. The PSC has not asserted any jurisdiction over the rates or rate structure of FMPA. The PSC also has the authority to determine the need for certain new transmission and generation facilities.

HEARING EXHIBIT - 00000459

COMPETITIVE POSITION OF FMPA AND THE PARTICIPANTS

General

The business, affairs and financial condition of municipal, cooperative and investor-owned electric utilities could be affected by the efforts now taking place on both the federal and state levels to restructure the electric utility industry. The goal of this restructuring effort is to change from a traditionally monopolistic industry to one in which there is open competition among electric suppliers on both the wholesale and retail levels. Past Florida and pending and past federal legislation seeks (or sought) to complete this restructuring by providing for competition at the retail level. No legislation is pending or proposed in Florida at this time for retail competition. Any such restructuring of the Florida retail electric utility industry is expected to affect FMPA and its members including the Participants.

FMPA's Competitive Position

FMPA has five separate power supply projects. Four of these projects are direct ownership interests in specific power plants. The fifth project, the All-Requirements Project, is a mixture of ownership interests in several power plants and transmission lines plus power purchases from other utilities. In fiscal year 2005, the Project accounted for more than 82% of FMPA's total revenues.

Power costs for FMPA's Projects have been comparable to rates of regional competitors. The cost of FMPA's All-Requirements Project, a system project, though at an all time high, has been competitive with comparable full-requirements rates (at 60% capacity factor) charged by Florida's two major investor-owned utilities that offer full-requirements service. The costs of FMPA's Stanton and Stanton II projects, which are unit-specific projects, have been lower than the comparable partial-requirements rates (at 75% load factor) charged by Florida's two major investor-owned utilities that offer partial-requirements service. The costs of FMPA's St. Lucie and Tri-City projects have been higher than the comparable partial-requirements rates (at 75% load factor) charged by investor-owned utilities. St. Lucie is among the lowest cost nuclear units in the country and, the cost of power generated by St. Lucie is currently competitive with the market price available from similarly situated natural gas and coal-fired units. The Tri-City Project is FMPA's smallest power supply project. It has had a slightly higher cost than regional benchmarks, but it is still competitive and its prospects are positive.

For all projects, FMPA is constantly searching for ways to reduce costs or better position the projects for the future. For the Project, power supply costs are the largest expense. FMPA has significant control and flexibility in its power supply to make decisions that affect the cost of power over time. FMPA is continually evaluating the Project's power supply resource mix. The power supply resources for the Project comes from power plants owned in part by the Project, power purchased from the Participants and power purchased by FMPA for the Project through a mixture of short, medium and long-term contracts with other electric utilities. This resource diversity provides valuable flexibility that enables FMPA to make economical power supply choices as various contracts for power purchases expire. In addition to cost effective power supply additions, FMPA is active in other areas-such as gaining equal access to the interstate transmission system-that have enhanced the All-Requirement Project's already strong competitive position. See "RISK MANAGEMENT."

Expected Effects of Retail Competition

Each member of FMPA, including the Participants, now has the exclusive right (and obligation) to serve electric utility consumers within its service area at rates set by the relevant governing body at levels determined solely at its discretion. However, if some form of customer choice or restructuring legislation (state or federal) is enacted, some or all of the members are likely to become subject to retail electric competition, where retail, commercial and industrial consumers within a member's service area will be able to choose their electric supplier from multiple competing suppliers, and will pay for such service based on rates set by competition and market conditions. It is not possible to predict the effects of any such competition upon the members or FMPA. However, some potential negative impacts to the members (and hence to FMPA) may include: (i) loss of customers, particularly industrial and commercial customers, (ii) increased costs to remaining customers, (iii) decreased revenues, (iv) decreases in transfers to each member's respective city or town general and other funds, (v) increased difficulties and higher costs in financing their respective systems, (vi) reduction in ratings on bonds and other debt, (vii) the need to recover both the costs of utility plant no longer needed to serve customers that have transferred to a

HEARING EXHIBIT - 00000460

competing supplier and the other costs of electric utility service not recoverable through market pricing ("stranded costs") and (viii) reductions in environmental and social programs relating to electric utility services. FMPA expects that in any restructuring of the electric utility industry, utilities, such as FMPA and the members, will be able to recover some or all of its stranded costs. Any such recovery is expected to come through specific charges which would be passed through to some or all retail consumers. However, no assurance can be given that any such recovery will take place.

Some potential positive effects of retail electric competition on the Participants might include a net gain of customers, lower costs to existing customers, more effective use of existing resources and increased revenues. There can be no assurances that any such positive effects would be experienced by any of the Participants.

Competitive Position of FMPA's Members

Most of FMPA's members currently have average system retail rates that are somewhat above the average retail rates of the state's major investor-owned utilities. The municipal systems have taken action to prepare for competition. Florida is expected to make a slower transition to retail choice because: (i) Florida's energy costs are consistent with the national average, (ii) Florida does not have a large number of industrial customers, which historically have advocated retail choice, (iii) Florida does not have an overabundance of electricity available for additional sales, (iv) Florida is a peninsular state with limited connections to other states, and (v) the existing interstate transmission lines are used at near capacity, leaving limited availability to import or export power.

In recent years, municipal electric utilities in Florida have implemented a wide variety of programs to prepare for competition. These programs include customer satisfaction initiatives, productivity and cost-control programs, power supply changes, electric rate studies that resulted in rate changes, special programs for large customers, revised utility charters, green power and other environmental initiatives, marketing and public relations programs, reduced transfers to city general funds, funding rate stabilization accounts, and new business ventures in areas such as natural gas, telecommunications, internet service and chilled water.

CERTAIN FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY

General

Several factors currently are affecting the electric utility industry, including increasing competition and related regulatory changes, financial difficulties faced by certain industry participants, and costs required to comply with environmental and other regulations. Public power utilities also are affected by factors related to their ability to issue tax-exempt obligations, and restrictions on the ability to sell power and energy to non-governmental entities produced by generation projects financed with outstanding tax-exempt debt. It is not possible to predict the impacts that these factors will have over time on FMPA and the Members. FMPA and its members, including the Participants, also could be adversely affected by technological or market developments that change the relative costs of electric power and energy provided by FMPA to the Participants in comparison with the costs of other utilities in Florida.

FMPA cannot predict what effects these factors will have on the business, operations and financial condition of FMPA or the Participants, but the effects could be significant. The following sections of this caption provide brief discussions of certain of these factors. However, these discussions do not purport to be comprehensive or definitive, and these matters are subject to change subsequent to the date of this Official Statement. Extensive information on the electric utility industry is, and is expected to be, available from legislative and regulatory bodies and other sources in the public domain.

Energy Policy Act of 1992

The Energy Policy Act of 1992 (the "Energy Policy Act") made fundamental changes in the federal regulation of the electric utility industry, particularly in the area of transmission access. The purpose of these changes, in part, was to bring about increased wholesale electric competition. In particular, the Energy Policy Act provides the Federal Energy Regulatory Commission ("FERC") with the authority, upon application by an electric

HEARING EXHIBIT - 00000461

utility, federal power marketing agency, or other power generator, to require a transmitting utility to provide transmission services to the applicant essentially on a cost-of-service basis. Municipally-owned electric utilities are "transmitting utilities" for purposes of these provisions of the Energy Policy Act. At this time, FERC does not have the authority to require "retail wheeling," under which a retail customer of one utility could obtain power from another utility or non-utility power generator.

The energy efficiency title of the Energy Policy Act required states and utilities to consider adopting integrated resource planning ("IRP"), which allows utility investments in conservation and other demand-side management techniques to be at least as profitable as supply investments. The PSC has adopted IRP as a standard. The Energy Policy Act also establishes new efficiency standards in industrial and commercial equipment and lighting and requires states to establish commercial and residential building codes with energy efficiency standards. Additionally, the Energy Policy Act requires utilities to consider energy efficiency programs in their IRPs. The effects on FMPA or the Project, if any, of these standards and requirements cannot be determined at this time.

FERC Transmission Initiatives

On April 24, 1996, FERC issued two final rules and a Notice of Proposed Rulemaking ("NOPR") to address and implement the transmission access provisions of the Energy Policy Act. Order No. 888 established the terms and conditions under which open access would be provided, and Order No. 889 established the rules of conduct surrounding the provision of open access, notably the separating of marketing from transmission and power operations. Municipally-owned electric utilities including FMPA and the Participants are not subject to FERC jurisdiction under these orders but may be denied reciprocal transmission services from a FERC-jurisdictional utility if they do not offer comparable transmission services.

In December 1999, FERC issued its Order No. 2000. Order No. 2000 represents a further measure in FERC's attempt to foster competition in wholesale power markets by encouraging all transmission-owning utilities, including municipal utilities, electric cooperatives and other public power entities, to join Regional Transmission Organizations ("RTO"). The implications of Order No. 2000 were further clarified and broadened when FERC issued its NOPR for a standard market design ("SMD") to accompany the formation of ISO/RTOs. Although this has occurred in many areas of the country, interest in forming such an organization in Florida seems to have diminished. The 2005 Energy Policy Act has further defused the impact of Order 2000 by making the SMD non-mandatory.

Florida has a longer history of quasi open-access transmission than many other parts of the country. An "Energy Broker" system was adopted in the late 1970's to promote efficient generation dispatch. The Energy Broker was eventually replaced by a strong system of bilateral agreements in the aftermath of Order Nos. 888 and 889. In Florida, considerable effort went into attempting to develop a workable ISO/RTO structure called "GridFlorida" pursuant to Order No. 2000. GridFlorida received provisional FERC approval but not PSC approval (the ability to put GridFlorida costs into investor owned utility rate bases was withheld by the PSC). Additional studies have shown GridFlorida not to be cost effective for Florida. Most recently, FMPA has submitted to the PSC a draft outline for an ISO structure that would potentially enhance open access, but the response to this submittal remains to be seen. A motion was recently filed with the PSC to close GridFlorida. FMPA opposes this motion.

2005 Energy Policy Act

On August 8, 2005, President Bush signed into law the 2005 Energy Policy Act. Among other things, the 2005 Energy Policy Act: (a) authorizes FERC to require "unregulated transmitting utilities" that formerly were exempt from regulation under sections 205 and 206 of the Federal Power Act (the "FPA") (including FMPA) to provide open access to their transmission systems and to comply with certain rate change provisions of section 205 of the FPA; (b) authorizes FERC to order refunds for certain short-term wholesale sales made by state and municipal power entities (including FMPA) if such sales violate FERC-approved tariffs or FERC rules; (c) allows load serving entities holding certain firm transmission rights to continue to use those rights to serve their customers; (d) provides that an "electric reliability organization" ("ERO") shall develop reliability standards for operation of the transmission grid subject to FERC approval, that compliance with such standards will be mandatory and enforceable by the ERO and FERC, and that the ERO may delegate its authority to regional entities subject to FERC approval; (e) adds to the FPA a prohibition on market manipulation and submission of false information, and expands civil and

HEARING EXHIBIT - 00000462

criminal penalties for violation of the FPA; (f) authorizes FERC to issue construction permits for transmission projects located in "national interest electric transmission corridors" (to be designated by the Department of Energy) in circumstances where the applicable state or regional siting agency does not timely authorize a project or imposes unreasonable conditions; (g) eliminates certain ownership restrictions on electric utilities regarding "qualifying facilities" under section 210 of the Public Utility Regulatory Reform Act, and authorizes FERC to eliminate prospectively the obligation of electric utilities to purchase and sell electricity to such qualifying facilities if certain market condition findings are made by FERC; (h) requires state utility regulatory commissions and "non-regulated electric utilities" (including the Authority) to consider adopting certain standards on net metering, fuel diversity, fossil fuel plant diversity, certain metering and time-based rate schedules and demand response, and interconnection with distributed generation facilities; (i) repeals the Public Utility Holding Company Act, effective six months after enactment of the 2005 Energy Policy Act; (j) increases FERC's authority to review mergers of public utility companies; and (k) directs FERC to establish transmission investment incentives in transmission rate structures for public utilities.

It is uncertain what the effects of the 2005 Energy Policy Act will be on FMPA or its members. The foregoing discussion of certain provisions of the 2005 Energy Policy Act does not purport to be a comprehensive discussion of the 2005 Energy Policy Act. Information on the 2005 Energy Policy Act is available from many sources in the public domain, and potential purchasers of the Offered Securities should obtain and review such information.

Environmental

FMPA's electric utility operations are subject to continuing environmental regulation. Federal, state, regional and local standards and procedures which regulate the environmental impact of FMPA's system are subject to changes which may arise from continuing legislative, regulatory and judicial action. Consequently, there is no assurance that the units in operation, under construction, or contemplated will remain subject to the regulations currently in effect, will always be in compliance with future regulations or will always be able to obtain all required operating permits. An inability to comply with environmental standards could result in increased costs of operating units, reduced operating levels or the complete shutdown of individual electric generating units not in compliance.

In March 2005, the Environmental Protection Agency (the "EPA") issued the Clean Air Interstate Rule ("CAIR") to permanently cap emissions of sulfur dioxide (SO2) and nitrogen oxides ("NOx") in the eastern United States. At the same time, the EPA issued the Clean Air Mercury Rule ("CAMR") to permanently cap and reduce mercury emissions from coal-fired power plants. These Rules create a multi-pollutant strategy to reduce emissions throughout the United States. CAIR will result in a reduction of SO2 emissions by over 70 percent and NOx emissions by over 60 percent from 2003 levels. CAMR will reduce utility emissions of mercury from 48 tons per year to 15 annual tons, a reduction of almost 70 percent. Both programs establish a cap-and-trade system based on EPA's current Acid Rain Program, which has produced remarkable results, reducing SO2 emissions more effectively and efficiently than expected, and resulting in significant environmental improvements. The EPA's rules include model cap-and-trade programs that states may adopt; however, states are allowed some flexibility in the implementation of the programs. Florida electric utilities, including FMPA, are participating with the Florida Department of Environmental Protection ("FDEP") in the development of the CAIR and CAMR programs for the state.

Proposed regulations governing the Total Maximum Daily Load ("TMDL") program, which were originally issued under the Clean Water Act in 1992, have the potential to impact the electric utility industry. A TMDL is the maximum amount of a given pollutant that a water body can absorb and still maintain its designated uses. Under Section 303(d) of the Federal Clean Water Act and the Florida Watershed Restoration Act, TMDL's must be developed within each state for all waters that are not meeting their designated uses and are defined as "impaired waters." A federal lawsuit was filed against EPA by several environmental groups, who allege that Florida's proposed impaired waters listing methodology fundamentally changes Florida water quality standards, and that EPA has a mandatory duty to review Florida's Impaired Waters Rule. FDEP and EPA are currently awaiting formal action by a District Judge. In addition, several other substantive issues have stalled EPA's approval of Florida's 303(d) list. Since the impaired water lists and methodology for enacting TMDL regulations have not yet been determined in Florida, the impact of this regulation on the industry is unknown at this point.

FMPA-POD3-00053

HEARING EXHIBIT - 00000463

The FDEP published the Florida Energy Plan on January 17, 2006, as directed by Governor Jeb Bush. The Department is proposing to modify the Power Plant Siting Act ("PPSA") and the Transmission Line Siting Act ("TLSA") in an effort to streamline the time required to complete certification for these facilities. Among other initiatives, the proposal revises the definition of "electrical power plant," to include associated facilities, such as fuel unloading facilities, fuel pipelines, railways, etc., in the definition of "electrical power plant." These offsite linear and fixed facilities currently require separate permits and approvals and are not required to be permitted as an associated facility of the power plant. This change in definition may in fact complicate and lengthen the overall certification proceedings, instead of streamlining, as originally intended. Florida's electric utilities, including FMPA, are participating in the Florida Energy Plan and the proposed revisions to the PPSA and TLSA. The Energy Plan also proposes to address significant utility issues such as hurricane response and fuel supply infrastructure.

By 2020, average demands for fresh water in Florida will increase by approximately 27% over 1995 levels and reach 9.1 billion gallons per day. This increase in demand for water supply may have an effect on the electric utility industry, as the regulating agencies develop programs and activities to address water resource planning. Electric generators may need to consider utilization of more expensive alternative sources of water or to limit consumptive use of the state's water resources.

FMPA cannot predict at this time whether any additional legislation or rules will be enacted which will affect FMPA's operations, and if such laws or rules are enacted, what the costs to FMPA might be in the future because of such action.

UNDERWRITING

A.G. Edwards & Sons, Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated J.P. Morgan Securities Inc. and UBS Securities LLC have agreed, subject to certain conditions, to purchase all, but not less than all, of the Offered Securities from FMPA at (i) with respect to the Series 2006B Bonds, an underwriters' discount of $593,163, and (ii) with respect to the Series 2006C Bonds, an underwriters' discount of $118,199. The underwriters will be obligated to purchase all of the Offered Securities if any are purchased.

FINANCIAL ADVISOR

Dunlap & Associates, Inc., Winter Park, Florida, is serving as financial advisor to FMPA. The financial advisor has assisted in the preparation of the Official Statement, and in other matters relating to the planning, structuring and issuance of the Offered Securities and has provided additional advice. Dunlap & Associates, Inc. is a financial advisory and consulting organization and is not engaged in the business of underwriting, marketing or trading of municipal securities or any other negotiable instruments.

LITIGATION

No litigation is pending or, to the knowledge of FMPA, threatened in any court to restrain or enjoin the issuance of any of the Offered Securities or the collection of revenues pledged or to be pledged to pay the principal of and interest on the Offered Securities, or in any way contesting or affecting the validity of the Offered Securities or the Resolution or the power to collect and pledge revenues to pay the Offered Securities.

ENFORCEABILITY OF REMEDIES

The remedies available to the Trustee or owners of the Offered Securities upon an event of default under the Resolution or the bond insurance policy are in many respects dependent upon judicial actions which are often subject to discretion and delay. Under existing constitutional and statutory law and judicial decisions, including specifically Title 11 of the United States Code, the remedies specified by the federal bankruptcy code, the Resolution and the Offered Securities may not be readily available or may be limited. The various legal opinions to be delivered concurrently with the delivery of the Offered Securities (including Bond Counsel's approving opinion) are qualified, as to the enforceability of the various legal instruments, by limitations imposed by bankruptcy, reorganization, insolvency or other similar laws affecting the rights of creditors enacted before or after such delivery.

FMPA-POD3-00054

HEARING EXHIBIT - 00000464

CREDIT RATINGS

Offered Securities

The Offered Securities are expected to be rated "AAA" by Fitch Ratings ("Fitch") and "Aaa" by Moody's Investors Service, Inc. ("Moody's"), on the date of issuance of the Offered Securities. The Offered Securities are expected to be assigned these ratings upon, and solely as a result of, the issuance of the Policies. See "BOND INSURANCE." Fitch and Moody's have also assigned underlying ratings of "A+" and "A1", respectively, to the Offered Securities.

General

The respective ratings by Fitch and Moody's of the Offered Securities reflect only the views of such organizations and any desired explanation of the significance of such ratings and any outlooks or other statements given by the rating agencies with respect thereto should be obtained from the rating agency furnishing the same, at the following addresses: Fitch Ratings, One State Street Plaza, New York, New York 10004 and Moody's Investors Service, Inc., 99 Church Street, New York, New York 10007. FMPA has furnished to each rating agency rating the Offered Securities information, including information not included in this Official Statement, about FMPA and the Offered Securities. Generally, a rating agency bases its rating and outlook (if any) on the information and materials furnished to it and on investigations, studies and assumptions of its own. There is no assurance such ratings for the Offered Securities will continue for any given period of time or that any of such ratings will not be revised downward or withdrawn entirely by any of the rating agencies, if, in the judgment of such rating agency or agencies, circumstances so warrant. Those circumstances may include, among other things, changes in or unavailability of information relating to FMPA or the Offered Securities. Any such downward revision or withdrawal of such ratings may have an adverse effect on the market price of the Offered Securities.

TAX MATTERS

Federal Income Taxes–Series 2006B Bonds

Generally. The Internal Revenue Code of 1986, as amended (the "Code") imposes certain requirements that must be met subsequent to the issuance and delivery of the Series 2006B Bonds for interest thereon to be and remain excluded from gross income for Federal income tax purposes. Noncompliance with such requirements could cause the interest on the Series 2006B Bonds to be included in gross income for Federal income tax purposes retroactive to the date of issue of the Series 2006B Bonds. FMPA has covenanted in the Resolution to comply with applicable requirements of the Code in order to maintain the exclusion of interest on the Series 2006B Bonds from gross income for Federal income tax purposes pursuant to Section 103 of the Code. In addition, FMPA has made certain factual representations and certifications of expectations as to tax matters, contained in a tax certificate executed by FMPA, in connection with the issuance and delivery of the Series 2006B Bonds.

In the opinion of Nixon Peabody LLP, Bond Counsel, under existing law and assuming compliance with the aforementioned covenant, and the accuracy of certain representations and certifications made by FMPA described above, interest on the Series 2006B Bonds is excluded from gross income for Federal income tax purposes under Section 103 of the Code. Bond Counsel is also of the opinion that such interest is not treated as a preference item in calculating the alternative minimum tax imposed under the Code with respect to individuals and corporations. Interest on the Series 2006B Bonds is, however, included in the adjusted current earnings of certain corporations for purposes of computing the alternative minimum tax imposed on such corporations.

Ancillary Tax Matters. Ownership of the Series 2006B Bonds may result in other Federal tax consequences to certain taxpayers, including, without limitation, certain S corporations, foreign corporations with branches in the United States, property and casualty insurance companies, individuals receiving Social Security or Railroad Retirement benefits, individuals seeking to claim the earned income credit, and taxpayers (including banks, thrift institutions and other financial institutions) who may be deemed to have incurred or continued indebtedness to purchase or to carry the Series 2006B Bonds. Bond Counsel is not rendering any opinion as to any Federal tax matters other than those described under the caption "Tax Matters". Prospective investors, particularly those who may be subject to special rules, are advised to consult their own tax advisors regarding the Federal tax consequences

FMPA-POD3-00055

HEARING EXHIBIT - 00000465

of owning and disposing of the Series 2006B Bonds, as well as any tax consequences arising under the laws of any state or other taxing jurisdiction.

Changes in Federal Tax Law and Post Issuance Events. From time to time proposals are introduced in Congress that, if enacted into law, could have an adverse impact on the potential benefits of the exclusion from gross income for Federal income tax purposes of the interest on the Series 2006B Bonds, and thus on the economic value of the Series 2006B Bonds. This could result from reductions in Federal income tax rates, changes in the structure of the Federal income tax rates, changes in the structure of the Federal income tax or its replacement with another type of tax, repeal of the exclusion of the interest on the Series 2006B Bonds from gross income for such purposes, or otherwise. It is not possible to predict whether any legislation having an adverse impact on the tax treatment of holders of the Series 2006B Bonds may be proposed or enacted.

Bond Counsel has not undertaken to advise in the future whether any events after the date of issuance and delivery of the Series 2006B Bonds may affect the tax status of interest on the Series 2006B Bonds. Bond Counsel expresses no opinion as to any Federal, State or local tax law consequences with respect to the Series 2006B Bonds, or the interest thereon, if any action is taken with respect to the Series 2006B Bonds or the proceeds thereof upon the advice or approval of other counsel.

Federal Income Taxes – Series 2006C Bonds (Taxable Auction Rate Securities)

The following is a summary of certain anticipated United States federal income tax consequences of the purchase, ownership and disposition of the Series 2006C Bonds. The summary is based upon the provisions of the Code, the regulations promulgated thereunder and the judicial and administrative rulings and decisions now in effect, all of which are subject to change. The summary generally addresses Series 2006C Bonds held as capital assets within the meaning of Section 1221 of the Code and does not purport to address all aspects of federal income taxation that may affect particular investors in light of their individual circumstances or certain types of investors subject to special treatment under the federal income tax laws, including but not limited to financial institutions, insurance companies, dealers in securities or currencies, persons holding such Bonds as a hedge against currency risks or as a position in a "straddle," "hedge," "constructive sale transaction" or "conversion transaction" for tax purposes, or persons whose functional currency is not the United States dollar. Potential purchasers of the Series 2006C Bonds should consult their own tax advisors in determining the federal, state or local tax consequences to them of the purchase, holding and disposition of the Series 2006C Bonds.

Generally. Interest on the Series 2006C Bonds is not excluded from gross income for federal income tax purposes and so will be fully subject to federal income taxation. Purchasers other than those who purchase Series 2006C Bonds in the initial offering at their principal amounts will be subject to federal income tax accounting rules affecting the timing and/or characterization of payments received with respect to such bonds. In general, interest paid on the Series 2006C Bonds will be treated as ordinary income and, after adjustment for any market discount or premium, principal payments will be treated as a return of capital.

Acquisition Discount. Certain owners who purchase Series 2006C Bonds at a price resulting in an adjusted basis that is less than the remaining redemption amount of such Series 2006C Bonds will have acquisition discount that may be included in gross income prior to the final maturity of such Series 2006C Bonds. Acquisition discount will be treated as accruing ratably or, at the election of the Bondholder, under a constant yield method based on daily compounding. Purchasers of any Series 2006C Bonds who acquire such Series 2006C Bonds at a discount should consult with their own tax advisors with respect to the timing of gross income under applicable federal income tax law and as to the state and local tax consequences of owning such Series 2006C Bonds.

Bond Premium. A purchaser of a Series 2006C Bond who purchases such Series 2006C Bond at a cost greater than its then principal amount will have amortizable bond premium. If the holder elects to amortize the premium under Section 171 of the Code (which election will apply to all Series 2006C Bonds held by the holder on the first day of the taxable year to which the election applies, and to all bonds thereafter acquired by the holder), such a purchaser must amortize the premium using constant yield principles based on the purchaser's yield to maturity. Amortizable bond premium is generally treated as an offset to interest income, and a reduction in basis is required for amortizable bond premium that is applied to reduce interest payments. Purchasers of any Series 2006C Bonds who acquire such Bonds at a premium (or with acquisition premium) should consult with their own tax advisors with respect to the determination and treatment of such premium for federal income tax purposes and with respect to state and local tax consequences of owning such Series 2006C Bonds.

FMPA-POD3-00056

HEARING EXHIBIT - 00000466

Sale or Redemption of Series 2006C Bonds. A bondowner's tax basis for a Series 2006C Bond is the price such owner pays for the Series 2006C Bond plus the amount of any original issue discount and market discount previously included in income, reduced on account of any payments received (other than "qualified periodic interest" payments) and any amortized bond premium. Gain or loss recognized on a sale, exchange or redemption of a Series 2006C Bond, measured by the difference between the amount realized and the Series 2006C Bond basis as so adjusted, will generally give rise to capital gain or loss if the Series 2006C Bond is held as a capital asset.

Information and Backup Withholding. A bondowner may, under certain circumstances, be subject to "backup withholding" at the applicable rate on, and with respect to, payments of principal or interest on, and to information reporting requirements with respect to, payments of principal and interest on, and to proceeds from the sale, exchange or retirement of, the Series 2006C Bonds. This backup withholding generally applies if the owner of a Series 2006C Bond (a) fails to furnish the Trustee or other payor with its taxpayer identification number; (b) furnishes the Trustee or other payor an incorrect taxpayer identification number; (c) fails to report properly interest, dividends or other "reportable payments" as defined in the Code; or (d) under certain circumstances, fails to provide the Trustee or other payor with a certified statement, signed under penalty of perjury, that the taxpayer identification number provided is its correct number and that the holder is not subject to backup withholding. Backup withholding will not apply, however, with respect to certain payments made to bondowners, including payments to certain exempt recipients (such as certain exempt organizations) and to certain Nonresidents (as defined below). Owners of the Series 2006C Bonds should consult their tax advisors as to their qualification for exemption from backup withholding and the procedure for obtaining the exemption.

The amount of "reportable payments" for each calendar year and the amount of tax withheld, if any, with respect to payments on the Series 2006C Bonds will be reported to the bondowners and to the Internal Revenue Service.

Nonresident Bondowners. Under the Code, interest and original issue discount income with respect to Series 2006C Bonds held by nonresident alien individuals, foreign corporations or other non-United States persons ("Nonresidents") generally will not be subject to the United States withholding tax (or backup withholding) if the Agency (or other person who would otherwise be required to withhold tax from such payments) is provided with an appropriate statement that the beneficial owner of the Series 2006C Bond is a Nonresident. Notwithstanding the foregoing, if any such payments are effectively connected with a United States trade or business conducted by a Nonresident bondowner, they will be subject to regular United States income tax, but will ordinarily be exempt from United States withholding tax.

ERISA. The Employees Retirement Income Security Act of 1974, as amended ("ERISA"), and the Code generally prohibit certain transactions between a qualified employee benefit plan under ERISA or tax-qualified retirement plans and individual retirement accounts under the Code (collectively, the "Plans") and persons who, with respect to a Plan, are fiduciaries or other "parties in interest" within the meaning of ERISA or "disqualified persons" within the meaning of the Code. All fiduciaries of Plans, in consultation with their advisors, should carefully consider the impact of ERISA and the Code on an investment in any Series 2006C Bonds.

State Taxes

Bond Counsel is also of the opinion that the Offered Securities and the interest thereon are exempt from taxation under existing laws of the State of Florida, except as to estate taxes and taxes imposed by Chapter 220, Florida Statutes, on interest, income or profits on debt obligations owned by corporations, banks and savings associations.

In all events, all investors should consult their own tax advisors in determining the federal, state, local and other tax consequences to them of the purchase, ownership and disposition of the Offered Securities.

APPROVAL OF LEGAL PROCEEDINGS

The issuance of the Offered Securities is subject to the approving opinion of Nixon Peabody LLP, New York, New York, Bond Counsel, in substantially the form set forth in APPENDIX D attached hereto. Certain legal matters will be passed on for FMPA by Frederick M. Bryant, Esquire, its General Counsel, and for the Underwriters by their counsel, Orrick, Herrington & Sutcliffe LLP, New York, New York.

HEARING EXHIBIT - 00000467

RELATIONSHIPS AMONG PARTIES

Wachovia, will act initially as the Trustee for the Offered Securities, is currently the lender with respect to the FMPA line of credit described herein, is the provider of the letter of credit for the Pooled Loan Project as described herein, has provided two taxable loans to FMPA as described herein, and has entered into an interest rate exchange agreement with FMPA. An affiliate of J.P. Morgan Securities Inc., an affiliate of Merrill Lynch, Pierce, Fenner & Smith Incorporated and an affiliate of UBS Securities LLC have each entered into an interest rate exchange agreement with FMPA. See "RISK MANAGEMENT—Interest Rate Swap Agreements."

VALIDATION

Judicial validation was not required by law for the issuance of the Offered Securities, and the Offered Securities have not been validated.

FMPA FINANCIAL STATEMENTS

FMPA has filed with the NRMSIRs named below and approved by the Securities and Exchange Commission (the "Commission") the following information:

- FMPA's Annual Audit Report for its fiscal year ended September 30, 2004, including its combining financial statements for such year, together with the report of Purvis Gray & Company with respect to these statements dated November 19, 2004.
- FMPA's Annual Audit Report for its fiscal year ended September 30, 2005, including its combining financial statements for such year, together with the report of Purvis Gray & Company with respect to these statements dated November 17, 2005.

These two Annual Audit Reports (as of their respective dates) are incorporated into this Official Statement to the same extent as if they were set forth in this Official Statement in full. The Annual Audit Reports contain information (on both an individual and combining basis) about the Project and the Other Projects of FMPA. The revenues of an Other Project are not security for the obligations of the Project, and the revenues of the Project are not security for an Other Project. See "OTHER FMPA PROJECTS."

Copies of these two Annual Audit Reports may be obtained from the FMPA website at www.fmpa.com or from the following NRMSIRs by paying their prescribed charges: (i) Bloomberg Municipal Repository, 100 Business Park Drive, Skillman, New Jersey 08558 telephone: (609) 279-3225 fax: (609) 279-5962 ; (ii) DPC Data Inc., One Executive Drive, Fort Lee, NJ 07024, telephone (201) 346-0701, fax: (201) 947-0107; (iii) FT Interactive Data, Attn: NRMSIR, 100 William Street, 15th Floor, New York, New York 10038, telephone: (212) 771-6999, 800-689-8466 fax: (212) 771-7390; and (iv) Standard & Poor's Securities Evaluations, Inc., 55 Water Street, 45th Floor, New York, NY 10041, telephone (212) 438-4595, fax: (212) 438-3975. Copies may also be obtained without charge from FMPA.

ADDITIONAL FMPA INFORMATION; CONTINUING DISCLOSURE

Under the Resolution, Bondholders may, upon written request to FMPA, receive copies of FMPA's annual audited financial statements. Bondholders also may inspect such materials during regular business hours at FMPA's offices upon such reasonable terms and conditions as FMPA may from time to time determine in its sole discretion. FMPA has committed to provide to Bondholders, upon request, copies of its annual audited financial statements, and other pertinent credit information, and has also committed to provide appropriate period credit information to the rating agencies which shall have rated FMPA securities.

FMPA has authorized a Continuing Disclosure Agreement (the "Undertaking") with respect to the Offered Securities to assist the Underwriters in complying with U.S. Securities and Exchange Commission Rule 15c2-12(b)(5). A summary of certain provisions of the Undertaking is included as Appendix F hereto. The Undertaking will be for the benefit of the holders of the Offered Securities, and the beneficial owners of the Offered Securities will be third-party beneficiaries thereof. Under the Undertaking, FMPA will be obligated to provide for itself and

FMPA-POD3-00058
HEARING EXHIBIT - 00000468

for the Major Participants financial information and operating data, financial statements, notice of certain events if material, and certain other notices, to NRMSIRs and others, and such obligations will be enforceable, all as described therein. FMPA's obligation to provide such information for Vero Beach will terminate on January 1, 2010. The execution of the Undertaking is a condition precedent to the obligation of the Underwriters to purchase the Offered Securities.

The Undertaking and commitments of FMPA described under this heading and in APPENDIX F hereto to furnish the above-described documents and information are agreements and commitments solely of FMPA, and the Underwriters have no responsibility to insure that FMPA complies with any such Undertaking or commitment. In addition, the Underwriters make no representation that any such documents or information will be furnished, or that any such documents or information so furnished will be accurate or complete, or sufficient for the purposes for which it may be used.

DISCLOSURE REQUIRED BY FLORIDA BLUE SKY REGULATIONS

Florida law requires FMPA to make a full and fair disclosure of any Offered Securities or other debt obligations which it has issued or guaranteed and which are or have been in default as to principal or interest at any time after December 31, 1975. FMPA is not and has not been in default as to principal of and interest on Offered Securities or other debt obligations to which revenues of FMPA are pledged.

MISCELLANEOUS

The references herein to the Resolution, the Interlocal Agreement, the Joint Power Act, the Florida Interlocal Cooperation Act, the Power Supply Contracts and the Capacity and Energy Sales Contracts are brief outlines of certain provisions thereof. Such outlines do not purport to be complete and reference is made to such documents and agreements for full and complete statements of such provisions. Copies of such documents are on file at the offices of FMPA and may be obtained upon request. Any statements involving matters of opinion, whether or not expressly so stated, are intended as such and not as representations of fact.

FLORIDA MUNICIPAL POWER AGENCY

By: /s/ Elie J. Boudreaux III
Chairman

By: /s/ Roger A. Fontes
General Manager and CEO

FMPA-POD3-00059

HEARING EXHIBIT - 00000469

[This Page Intentionally Left Blank]

HEARING EXHIBIT - 00000470

APPENDIX A

MEMBERS' PARTICIPATION IN FMPA PROJECTS[1]

Member	Stanton Project(2)		Stanton II Project(2)		St. Lucie Project		Tri-City Project		All Requirements Project (3)	Pooled Loan Project(4)
	Entitlement Share	MW	Entitlement Share	MW	Entitlement Share	MW	Entitlement Share	MW	MW(4)	
City of Alachua	–	–	–	–	0.431%	0.3	–	–	–	–
City of Bushnell	–	–	–	–	–	–	–	–	6	X
City of Clewiston	–	–	–	–	2.202	1.6	–	–	29	X
City of Fort Meade	–	–	–	–	0.336	0.2	–	–	11	–
Fort Pierce Utilities Authority	24.390%	15.4	16.4887%	16.4	15.206	11.2	22.727%	5.1	125	X
City of Green Cove Springs(5)	–	–	–	–	1.757	1.3	–	–	29	–
Town of Havana	–	–	–	–	–	–	–	–	6	–
City of Homestead	12.195	7.7	8.2443	8.2	8.269	6.1	22.727	5.1	–	–
City of Jacksonville Beach	–	–	–	–	7.329	5.4	–	–	192	–
Utility Board of the City of Key West	–	–	9.8932	9.9	–	–	54.546	12.3	145	X
Kissimmee Utility Authority	12.195	7.7	32.9774	32.9	9.405	6.9	–	–	346	–
City of Lake Worth	16.260	10.2	–	–	24.870	18.3	–	–	97	–
City of Leesburg	–	–	–	–	2.326	1.7	–	–	120	X
City of Moore Haven	–	–	–	–	0.384	0.3	–	–	–	–
City of Newberry	–	–	–	–	0.184	0.1	–		7	–
Utilities Commission, City of New Smyrna Beach	–	–	–	–	9.884	7.3	–	–	–	X
City of Ocala	–	–	–	–	–	–	–	–	308	–
City of St. Cloud	–	–	14.6711	14.6	–	–	–	–	–	–
City of Starke(5)	2.439	1.5	1.2366	1.2	2.215	1.6	–	–	18	–
City of Vero Beach(5)	32.521	20.5	16.4887	16.4	15.202	11.2	–	–	174	–
	100.000%	63.0	100.000%	99.6	100.000%	73.5	100.000%	23.0	1,613	NA

(1) This table is as of September 30, 2005. The table does not reflect purchases and sales of capacity and energy between Members.

(2) Reflects current Project Entitlement Shares after giving effect to transfers of project entitlement shares to KUA from other participants in these projects.

(3) Participants non-coincident peak demand in the 2005 fiscal year served from this project. Includes demand served by excluded resources.

(4) X = Members with loans outstanding as of September 30, 2005.

(5) See "PROJECT PARTICIPANTS— Change in Status of Certain Participants."

FMPA-POD3-00061

HEARING EXHIBIT - 00000471

[This Page Intentionally Left Blank]

HEARING EXHIBIT - 00000472

APPENDIX B

THE MAJOR PARTICIPANTS

Appendix B presents certain information for the Major Participants which was collected and compiled by FMPA from data supplied by each of the Major Participants. Text descriptions were developed with each of the Major Participant's representatives; statistical facts were extracted from records regularly maintained by each of the Major Participants; and historical financial data was summarized from each Major Participant's independent certified audits. While the Agency makes no representations as to the adequacy or accuracy of the information contained in this Appendix B, it believes such information to be reliable. See "Project Participants – Change in Status of Certain Participants."

(remainder of this page intentionally left blank)

HEARING EXHIBIT - 00000473

CITY OF JACKSONVILLE BEACH

General

The City of Jacksonville Beach ("Jacksonville Beach") is located in Duval County approximately 18 miles east of Jacksonville. Jacksonville Beach operates under the City Council/City Manager form of government. Jacksonville Beach operates and maintains electric, water and wastewater utility operations. As a matter of policy, revenue financing combines the resources of all utility operations; thus, these utility services are integrated and pledged for purposes of the All-Requirements Power Supply Contract. As the Chief Administrative Officer, the City Manager appoints the Director of Electric Utilities.

Jacksonville Beach is a residential and commercial community whose citizens, for the most part, work in the metropolitan Jacksonville area. Additionally, Jacksonville Beach is a major recreation area for the people of Duval County, Florida.

Electric Utility System

Jacksonville Beach entered into an All-Requirements Power Supply Project Contract with FMPA and became a full requirements customer of the Agency on May 1, 1986. Excluded Power Supply Resources for Jacksonville Beach include only its entitlement share in the Agency's St. Lucie Project (which is 7.329% of the capacity and energy of the Agency's total ownership share of St. Lucie Unit No. 2). Jacksonville Beach owns one 230 kV transmission substation that ties to Florida Power and Light and JEA. They also have 12 distribution substations, which deliver energy at 26 kV, 12 kV, and 4 kV levels. Approximately 50% of the distribution circuits are underground installations. The Jacksonville Beach electric utility operates under the name, Beaches Energy Services.

Service Area and Customers

The Jacksonville Beach electric utility service area encompasses approximately 45 square miles including the neighboring town of Neptune Beach, and the unincorporated areas of Ponte Vedra and Palm Valley located in northeast St. Johns County. Portions of this territory have been assigned to Jacksonville Beach by the PSC. Forty percent of the customers served reside within the Jacksonville Beach city limits.

No one customer accounted for more than 5% of electric revenues for the year ended September 30, 2005.

HEARING EXHIBIT - 00000474

CITY OF JACKSONVILLE BEACH

SUMMARY OF OPERATING RESULTS(1)
(Dollars in Thousands)

	For The Fiscal Years Ended September 30,				
	2001	2002	2003	2004	2005
Customers (annual average)	31,062	31,210	31,351	31,866	31,954
System Requirements					
Peak Demands (MW)	196	189	228	179	192
Energy(MWh)	741,655	750,881	777,369	791,699	804,322
Total Energy Sales(MWh)	702,773	692,255	749,014	753,561	749,783
Total Operating Revenues	$72,326	$71,239	$73,968	$79,096	$88,717
Operating Expenses:					
Total Purchased Power	43,966	42,095	45,656	49,845	57,172
All Other Operating Expenses (excluding depreciation)	10,182	10,196	10,923	12,116	11,840
Total Operating Expenses (excluding depreciation)	54,148	52,291	56,579	61,961	69,012
Net Operating Revenues Available for Debt Service	18,178	18,948	17,389	17,135	19,705
Other Income (Deductions)—Net	2,987	2,130	1,183	1,321	1,887
Net Revenues and Other Income Available for Debt Service	21,165	21,078	18,572	18,456	21,592
Debt Service—Revenue Bonds	7,481	7,804	7,227	5,575	5,740
Debt Service Ratios					
Actual	2.83x	2.70x	2.57x	3.31x	3.76x
Per Bond Resolution Rate Covenant	1.25x	1.25x	1.25x	1.25x	1.25x
Balance available for renewals, replacements, capital additions and other lawful purposes	13,684	13,274	11,345	12,881	15,852
Transferred to General Fund (Jacksonville Beach)(2)	$3,053	$3,365	$3,390	$3,617	$3,514

CONDENSED BALANCE SHEET(1)
(Dollars in Thousands)

	For Fiscal Years Ended September 30,	
	2004	2005
ASSETS:		
Net Utility Plant	$108,300	$110,902
Restricted Assets	8,758	8,410
Current Assets	52,262	54,972
Total Asset	$169,320	$174,284
LIABILITIES AND EQUITY:		
Current Liabilities	$ 17,531	$ 14,441
Retained Earnings	102,631	112,611
Long Term Debt	49,158	47,232
Total Liabilities and Equity	$169,320	$174,284

(1) Electric, water, and wastewater utility.
(2) Established by Jacksonville Beach policy at 4.5 mills per kWh purchased.

UTILITY BOARD OF THE CITY OF KEY WEST

General

The City of Key West was first incorporated in 1828 and is the County seat of Monroe County, Florida. It is located near the southern extreme of the Florida Keys, a string of coral islands extending in a southwesterly arc from Biscayne Bay to the Dry Tortugas, and lies further south than any other point in the continental United States. The Utility Board of the City of Key West (the "Board") operates the municipally owned electric generation, transmission and distribution facilities in the service area.

The Board is composed of a Chairman who is elected for a term of two years and four members who are elected for terms of four years by the registered electors of the City of Key West. The Board appoints the Manager of the System. Only electric system revenues are pledged for purposes of the Power Sales Contract and the Project Support Contract for the Tri-City and Stanton II Projects and the All-Requirements Power Supply Contract.

Electric Utility System

The Board currently owns, operates and maintains nine generating units with a total maximum net continuous capability of 50.4 MW. This includes a combustion turbine unit (20 MW) and two medium speed diesel units (total 17.4 MW) on Stock Island, and six peaking diesel units located on Stock Island, Big Pine Key and Cudjoe Key (total 13 MW). The Board joined the All-Requirements Project effective April 1, 1998. FMPA installed two additional combustion turbines that are owned by FMPA but operated by the Board. With the FMPA units, island generation totals 84.4 MW. The Utility Board now operates under the name KEYS Energy Services ("KEYS").

Service Area and Customers

The service area of KEYS consists of the lower Florida Keys, extending approximately 44 miles in an east-west direction from Pigeon Key, adjacent to the service area of the Florida Keys Electric Cooperative Association, Inc. to the City of Key West, representing approximately 74 square miles.

The United States Navy (the "Navy") is the largest customer of the Board, having accounted for approximately 10.4% and 10.3% of kilowatt hours sold in fiscal 2005 and 2004 respectively. KEYS' contract with the Navy contains provisions for minimum billing, service reduction and exclusive service provisions. Pursuant to this contract, KEYS has agreed to provide a maximum of 15 MW of power at multiple locations.

KEYS executed an amendment to the Navy's service contract on December 8, 1999, which modified the existing rate schedule. At the time of such amendment, the term of the contract was extended to September 1, 2004 subject to certain termination and renegotiation provisions. In February 2004, both parties agreed that the contract between KEYS and the Navy shall continue in effect through September 1, 2007. All terms and conditions remain unchanged and in full force and effect.

KEYS submitted a proposal on June 18, 2003 in response to the Department of the Navy's Solicitation N62467-00-R-1801 to privatize electric systems at NAS Key West. In January 2005, the Navy notified KEYS that it had been selected as a best value respondent to the Navy's solicitation. However, after several months of negotiations, the parties were not able to reach agreement on the terms and conditions of the privatization ontract between the Navy and KEYS.

FMPA-POD3-00066

HEARING EXHIBIT - 00000476

UTILITY BOARD OF THE CITY OF KEY WEST

SUMMARY OF OPERATING RESULTS(1)
(Dollars in Thousands)

	For The Fiscal Years Ended September 30,				
	2001	2002	2003	2004	2005
Customers (annual average)	28,532	28,754	29,021	29,234	29,545
System Requirements					
Peak Demands (MW)	130	134	139	140	146
Energy(MWh)	720,627	757,538	793,940	781263	781,141
Total Energy Sales(MWh)	670,864	703,633	736,221	734,834	723,978
Total Operating Revenues	$69,988	$66,658	$72,994	$81,339	$83,479
Operating Expenses:					
Total Power Production and Power Supply	36,159	36,159	42,535	45,411	50,361
All Other Operating Expenses (excluding depreciation)	16,745	17,851	18,171	19,660	21,612
Total Operating Expenses (excluding depreciation)	52,904	54,010	60,706	65,071	71,973
Net Operating Revenues Available for Debt Service	17,084	12,648	12,288	16,268	11,506
Other Income (Deductions)-Net	3,134	1,929	996	1,040	1,487
Net Revenues and Other Income Available for Debt Service	20,218	14,577	13,284	17,308	12,993
Debt Service-Revenue Bonds	9,293	8,493	8,508	8,508	8,510
Debt Service Ratios					
Actual	2.18x	1.72x	1.56x	2.00x	2.00x
Per Bond Resolution Rate Covenant	1.25x	1.25x	1.25x	1.25x	1.25x
Balance available for renewals, replacements, capital additions and other lawful purposes	10,925	6,084	4,776	8,800	4,483
Transferred to General Fund (City of Key West)	$324	$334	$318	$326	$341

CONDENSED BALANCE SHEET(1)
(Dollars in Thousands)

	For Fiscal Years Ended September 30,	
	2004	2005
ASSETS:		
Net Utility Plant	$115,032	$114,112
Restricted Assets	25,792	14,709
Current Assets	16,404	33,723
Total Assets	$157,228	$162,544
LIABILITIES AND EQUITY:		
Current Liabilities	$ 17,931	$ 20,167
Retained Earnings	61,511	57,119
Long Term Debt	77,786	75,258
Total Liabilities and Equity	$157,228	$162,544

(1) Electric utility only.

FMPA-POD3-00067

HEARING EXHIBIT - 00000477

KISSIMMEE UTILITY AUTHORITY

General

The City of Kissimmee ("Kissimmee") is approximately 18 miles south of Orlando and 7 miles east of the Walt Disney World Complex. Kissimmee is the county seat of Osceola County, the geographical center of Florida. Kissimmee was incorporated in 1883 and has a Commission/Manager form of government. The Kissimmee Utility Authority ("KUA"), which became effective October 1, 1985, operates and maintains the electric system. Only the electric utility system revenues of KUA are pledged for the purposes of the Power Sales and Project Support Contracts for the St. Lucie, Stanton and Stanton II Projects and All-Requirements Power Supply Contract.

The economy of Osceola County is primarily based upon tourism, cattle ranching and agriculture.

Electric Utility System

KUA entered into an All-Requirements Power Supply Contract with FMPA and became a full requirements customer as of October 1, 2002.

KUA's generating facilities consist of a combined cycle plant with a capability of 47 MW. KUA also owns 50% of a combustion turbine unit (20MW) and 50% of a combined cycle unit (60MW) and 50% of a combined cycle unit (125 MW) with FMPA's All-Requirements Project. KUA operates all of these units. In addition, KUA has (i) a 0.6754% (5.6 MW) undivided ownership interest in the Crystal River No. 3 nuclear-fueled generating plant, which is principally owned and operated by Progress Energy Florida, Inc. ("PEF"); (ii) a 4.8% (21 MW) undivided ownership interest in Stanton Energy Center Unit No. 1, which is operated by Orlando Utilities Commission ("OUC") (iii) a 12.2% (9.0 MW) undivided ownership interest in the Indian River Combustion Turbine Units A and B, which are also operated by OUC and (iv) a 3.5% (22.7 MW) ownership interest in Stanton Unit A, a gas-fired combined cycle unit located at OUC's Stanton Energy Center site and operated by Southern Company. KUA is a member of and has contracted with FGU which acts as an agent to KUA and other Florida utilities. FGU makes bulk purchases of natural gas which consists of a combination of spot market purchases, short-term winter firm supplies and medium term contracts. As a result of KUA joining the All-Requirements Project and entering into a Capacity Energy Sales Contract with the All-Requirements Project, these facilities are treated as resources of the All-Requirements Project.

KUA's 230 kV and 69 kV transmission system includes interconnections with PEF, OUC, TECO and the City of St. Cloud. Sixteen sub-stations supply the distribution system at voltages of 13.2 kV and 4.16 kV. The current system is approximately 59% underground and 41% overhead construction. Approximately 80% of all new distribution system installations are constructed underground.

Service Area and Customers

KUA's electric utility service area encompasses approximately 85 square miles with Kissimmee's ten square-mile area near the center and 47% of electric customers served reside within the city limits. KUA has a PSC approved territorial agreement with PEF and St. Cloud, its neighboring utilities.

No one electric customer accounted for more than 5% of the electric revenues for the year ended September 30, 2005.

HEARING EXHIBIT - 00000478

KISSIMMEE UTILITY AUTHORITY
SUMMARY OF OPERATING RESULTS (1)
(Dollars in Thousands)

	For The Fiscal Years Ended September 30,		
	2003	2004	2005
Customers (annual average)	50,587	53,197	57,425
System Requirements			
Peak Demands (MW)	272	285	319
Energy(MWh)(2)			
Total Energy Sales(MWh)(2)	1,212,976	1,225,771	1,318,801
Total Operating Revenues	$127,335	$132,776	$154,652
Operating Expenses:			
Total Power Production and Purchased Power	79,996	83,142	103,432
All Other Operating Expenses			
(excluding depreciation)	15,865	19,084	22,436
Total Operating Expenses			
(excluding depreciation)	95,861	102,226	125,868
Net Operating Revenues			
Available for Debt Service	31,475	30,550	28,784
Other Income (Deductions)-Net	1,937	1,511	2,019
Net Revenues and Other Income			
Available for Debt Service	33,779	32,864	31,629
Debt Service-Revenue Bonds	19,037	20,664	18,313
Debt Service Ratios			
Actual	1.77x	1.59x	1.73x
Per Bond Resolution Rate			
Covenant	1.25x	1.10x	1.10x
Balance available for renewals,			
replacements, capital additions			
and other lawful purposes	10,250	7,829	8,925
Transferred to General Fund			
(Kissimmee)(3)	$7,665	$7,674	$8,279

CONDENSED BALANCE SHEET(1)
(Dollars in Thousands)

	For Fiscal Years Ended September 30,	
	2004	2005
ASSETS:		
Utility Plant	$234,991	$235,311
Restricted Assets	87,153	95,111
Current Assets	94,281	97,979
Total Assets	$464,414	$479,572
LIABILITIES AND EQUITY:		
Current Liabilities	$ 14,915	$ 18,305
Utility Plant	27,456	37,647
Long Term Debt	277,405	268,971
Total Liabilities and Equity	$464,414	$479,572

(1) Electric utility participation only.
(2) Excluding sales to other electric utilities, if any.
(3) Established by KUA at $6.24 mills per kWh sold.

FMPA-POD3-00069

HEARING EXHIBIT - 00000479

CITY OF OCALA

General

The City of Ocala ("Ocala") is located in Marion County near the geographic center of the State of Florida, approximately 42 miles south of Gainesville and 91 miles north of Orlando. Ocala operates under the City Council/City Manager form of government. Ocala operates and maintains electric, water and wastewater utility operations which are integrated for bond issuance purposes. Thus electric and water and wastewater revenues will be pledged for purposes of the All-Requirements Power Supply Contract. As the Chief Administrative Officer, the City Manger appoints the Directors of Electric and Water Utilities. The incumbent Director of the Electric System is Rebecca Mattey. She was appointed director in April 2004. She is responsible for the overall administration of the Electric System and telecommunications. She holds a Bachelor of Science degeree from the University of Southern Illinois.

The economy of Ocala and Marion County is diversified. The three major payroll classifications in the private sector are: services (tourism), manufacturing and retail trade, in that order. Next are wholesale trade and construction. Agriculture and the thoroughbred horse industry are also major contributors to the area economy. As the center of retail trade for a four county area, the City of Ocala and Marion County have each experienced significant growth in both retail sales and in the number of establishments catering to the retail sector.

Electric Utility System

The City of Ocala entered into an All-Requirements Power Supply Contract with FMPA and became a full requirements customer of the Agency on May 1, 1986. Excluded Power Supply Resources for the City of Ocala include its partial ownership in PEF's Crystal River 3 nuclear unit, which equals 1.3333% of that unit (or 10,504 kW based on current net summer rating). The Electric System is presently served from three 230/69KV substations. Dearmin Substation is connected to Progress Energy Corporation thought Progress Energy's Silver Springs Substation located in the southeast corner of the city limits and within the service area of the City. Ergle Substation is connected to the Seminole Electric Cooperative's Silver Springs North Substation and is outside the City but within the service area. In 1993 the City constructed a third 230/69KV substation named Red Oak in the western portion of the City, and it is connected to Ergle Substation.

The 230/69KV substations currently feed into a sub-transmission system, consisting of 15 69/12.47KV substations, which feeds into a 12.47KV system of distribution to users. The City has built a new substation in the northwest portion of its service area along US Highway 27. A six mile 69KV transmission line extension will accompany this addition to accommodate load growth. A new substation is also planned for the northeast section of the Electric System at the intersection of State Road 314 and State Road 40. In the current fiscal year the City plans to add 5 miles of transmission line to extend the loop to this section. The City completed the construction of a new 28,000 square foot Customer Service Office and installed a new customer information system.

The Electric System includes the City's undivided share of the Crystal River Nuclear Plant, Unit No. 3 ("CR-3") including the three substations, which interface with the state-wide bulk power system and the distribution substations that interface the City's (distribution) Electric System.

The City purchases power from FMPA through the 230KV statewide bulk power system. The City Electric System receives 4.0% of its power from CR-3 and 96% from FMPA.

Service Area and Customers

Ocala's service area encompasses approximately 171 square miles. Ocala has received PSC approval of territorial agreements with Clay Electric Cooperative and Sumter Electric Cooperative. The Electric System has approximately 49,000 customers. Sixty-one percent of the customers served by Ocala reside within the city limits

No one customer accounted for more than 5% of electric revenues for the year ended September 30, 2004. The audit for the fiscal year ended September 30, 2005 is not yet available.

HEARING EXHIBIT - 00000480

CITY OF OCALA

SUMMARY OF OPERATING RESULTS(1)(3)
(Dollars in Thousands)

	2001	2002	2003	2004
Customers (annual average)	46,547	47,096	47,049	48,326
System Requirements				
Peak Demands (MW)	267	289	314	306
Energy(MWh)	1,287,624	1,304,473	1,362,799	1,373,565
Total Energy Sales(MWh)	1,223,243	1,239,249	1,275,044	1,291,296
Total Operating Revenues	$101,142	$100,779	$108,189	$121,366
Operating Expenses:				
Total Power Production and Purchased Power	68,318	65,704	72,738	83,608
All Other Operating Expenses (excluding depreciation)	18,734	20,074	21,242	23,831
Total Operating Expenses (excluding depreciation)	87,052	85,778	93,980	107,439
Net Operating Revenues Available for Debt Service	14,090	15,001	14,209	13,927
Other Income (Deductions)—Net	4,458	2,863	1,834	630
Net Revenues and Other Income Available for Debt Service	18,548	17,864	16,043	14,557
Debt Service—Revenue Bonds	630	244	2,271	2,299
Debt Service Ratios				
Actual	29.44x	73.34x	7.06x	6.33x
Per Bond Resolution Rate Covenant	1.25x	1.25x	1.25x	1.25x
Balance available for renewals, replacements, capital additions and other lawful purposes	17,918	17,620	13,772	12,258
Transferred to General Fund (Ocala)(2)	$9,714	$9,903	$10,703	$10,890

CONDENSED BALANCE SHEET(1)
(Dollars in Thousands)

	For Fiscal Years Ended September 30,	
	2003	2004
ASSETS:		
Net Utility Plant	$ 83,532	$ 83,953
Restricted Assets	14,596	13,305
Current Assets	55,831	52,886
Other Assets	1,836	3,979
Total Asset	$155,795	$154,123
LIABILITIES AND EQUITY:		
Current Liabilities	$ 16,927	$ 17,614
Other Liabilities	6,161	6,989
Retained Earnings	126,472	125,287
Long Term Debt	6,235	4,233
Total Liabilities and Equity	$155,795	$154,123

(1) Electric utility operations.
(2) The transfer to Ocala's general fund is determined by (kWh sold – kWh streetlights) x 7 mills + surcharge of 10% of bill for customers outside of city limits.
(3) The audit for the fiscal year ended September 30, 2005 is not yet available.

FMPA-POD3-00071

HEARING EXHIBIT - 00000481

CITY OF VERO BEACH

General

The City of Vero Beach ("Vero Beach"), the county seat of Indian River County, is located on the east coast of Florida mid-way between Miami and Jacksonville. Vero Beach was incorporated in 1925 and adopted a City Council/City Manager form of government in 1951. Five City Council members are elected for two-year overlapping terms. At the organizational meeting succeeding each election, the Mayor is selected by a majority vote of the five sitting Councilmen and serves for a term of one year. While Vero Beach owns and operates electric, water and sewer utilities, electric revenue financing is, as a matter of operating policy, accomplished separately from financing related to other utility operations, thus only electric utility system revenues are pledged for the purposes of the Power Sales Contracts and Project Support Contracts for the St. Lucie, Stanton and Stanton II Projects and All-Requirements Power Supply Contract.

The economy of Indian River County is based upon a combination of agriculture, tourism, light manufacturing and retirement income.

Electric Utility System

Vero Beach joined the FMPA All-Requirements Project in June 1998, which supplies all of the power resources of Vero Beach except for those resources provided by the St. Lucie Project. Vero Beach's 69 kV transmission system includes interconnections with FPL and a 138 kV tie line with the Fort Pierce Utilities Authority. The transmission system completely loops the service area, enhancing service reliability. Eight substations supply voltage at 13 kV to a predominantly overhead distribution system. An additional substation is presently under construction to increase system capacity and reliability as system demand grows.

Service Area and Customers

Vero Beach's electric utility service area encompasses approximately 37 square miles with approximately 45% of electric utility customers residing within city limits. Vero Beach has a territorial agreement with FPL, its only neighboring utility, which has been approved by the PSC.

No single electric customer accounted for more than 5% of the electric revenues for the year ended September 30, 2005.

HEARING EXHIBIT - 00000482

CITY OF VERO BEACH
SUMMARY OF OPERATING RESULTS(1)(4)
(Dollars in Thousands)

	For The Fiscal Years Ended September 30,				
	2001	2002	2003	2004	2005
Customers (annual average)	30,720	31,148	32,288	32,727	32,406
System Requirements					
Peak Demands (MW)(2)	176	178	203	198	185
Energy(MWh)	716,521	742,350	749,997	754,999	777,708
Total Energy Sales(MWh)	687,576	702,246	734,368	686,723	772,428
Total Operating Revenues	$58,680	$61,666	$63,425	$65,180	$81,860
Operating Expenses:					
Total Power Production and Purchased Power	42,272	38,010	42,538	46,756	5,1466
All Other Operating Expenses (excluding depreciation)	6,568	8,048	8,355	10,907	16,444
Total Operating Expenses (excluding depreciation)	48,423	46,055	50,893	57,664	67,910
Net Operating Revenues Available for Debt Service	10,257	15,611	13,090	7,487	13,950
Other Income (Deductions)—Net	2,605	1,512	757	2,957	9,464
Net Revenues and Other Income Available for Debt Service	12,862	17,123	13,847	10,443	23,414
Debt Service-Revenue Bonds	6,271	6,137	6,071	5,477	5,404
Debt Service Ratios					
Actual	1.90x	2.79x	1.91x	1.91x	4.33x
Per Bond Resolution Rate Covenant	1.25x	1.25x	1.25x	1.25x	1.25x
Balance available for renewals, replacements, capital additions and other lawful purposes	6,591	10,986	7,776	4,966	18,010
Transferred to General Fund (Vero Beach)(3)	$3,912	$4,198	$4,287	$4,799	$5,623

CONDENSED BALANCE SHEET(1)
(Dollars in Thousands)

	For Fiscal Years Ended September 30,	
	2004	2005
ASSETS:		
Net Utility Plant	$115,690	$117,139
Restricted Assets	9,359	11,213
Current Assets	22,094	26,684
Total Assets	$14,7143	$155,037
LIABILITIES AND EQUITY:		
Current Liabilities	$ 12,372	$ 12,920
Retained Earnings	64,380	74,053
Long Term Debt	70,391	68,064
Total Liabilities and Equity	$147,143	$155,037

(1) Electric utility operation only.
(2) Vero Beach reports that its peak demand is highly weather sensitive.
(3) Based on rate of return on equity and contributions in lieu of ad valorem taxes.

FMPA-POD3-00073

HEARING EXHIBIT - 00000483

[This Page Intentionally Left Blank]

HEARING EXHIBIT - 00000484

APPENDIX C

SUMMARY OF CERTAIN PROVISIONS OF THE RESOLUTION AND POWER SUPPLY CONTRACTS

This Appendix contains summaries of certain provisions of FMPA's All-Requirements Power Supply Project Revenue Bond Resolution, adopted on March 22, 1985, as amended and restated in its entirety on May 23, 2003, as supplemented and amended, including as supplemented by the Multiple Series Supplemental All-Requirements Power Supply Project Revenue Bond Resolution, adopted on November 2, 2005, as amended by Amendment No. 1 to Multiple Series Supplemental All-Requirements Power Supply Project Revenue Bond Resolution adopted on November 2, 2005, and as amended by Amendment No. 2 to the Multiple Series All-Requirements Power Supply Project Revenue Bond Resolution adopted on February 23, 2006 (the "Supplemental Resolution" and, together with the All-Requirements Power Supply Project Revenue Bond Resolution, the "Resolution"); and (ii) separate All-Requirements Power Supply Project Contracts, as amended and restated (the "All-Requirements Power Supply Contracts") between FMPA and the Participants. These summaries are not to be considered full statements of the terms of the respective documents and accordingly are qualified by the reference to such respective documents and subject to the full text thereof. Copies of such documents may be obtained from FMPA on request. Capitalized terms not otherwise defined herein have the meanings set forth in the respective documents or the Official Statement.

SUMMARY OF CERTAIN PROVISIONS OF THE RESOLUTION

The following is a general summary of certain provisions of the Resolution. Certain additional provisions relating specifically to the Offered Securities issued pursuant to the Supplemental Resolution and Bond Series Certificate are presented under "DESCRIPTION OF THE OFFERED SECURITIES" and "SECURITY AND SOURCES OF PAYMENT FOR THE OFFERED SECURITIES."

Definitions

Accrued Aggregate Debt Service shall mean, as of any date of calculation, an amount equal to the sum of the amounts of accrued Debt Service with respect to all Series and all Parity Debt, calculating the accrued Debt Service with respect to each Series at an amount equal to the sum of (i) interest on the Bonds of such Series and all Parity Debt accrued and unpaid and to accrue to the end of the then current calendar month, and (ii) Principal Installments due and unpaid and that portion of the Principal Installment for such Series and such Parity Debt next due which would have accrued (if deemed to accrue in the manner set forth in the definition of Debt Service) to the end of such calendar month; provided, however that there shall be excluded from the calculation of Accrued Aggregate Debt Service any Principal Installments which are Refundable Principal Installments.

Adjusted Aggregate Debt Service for any period means, as of any date of calculation, the Aggregate Debt Service for such period except that, if any Refundable Principal Installment for any Series of Bonds is included in Aggregate Debt Service for such period, Adjusted Aggregate Debt Service shall mean Aggregate Debt Service determined as if each such Refundable Principal Installment had been payable, over a period extending from the due date of such Principal Installment through the later of the 35th anniversary of the issuance of such Series of Bonds or the 10th anniversary of the due date of such Principal Installments, in installments which would have required equal annual payments of principal and interest over such period. Interest deemed payable in any Fiscal Year after the actual due date of any Refundable Principal Installment of any Series of Bonds shall be calculated at the weighted average rate of interest actually payable on the Bonds of such Series at the time the calculation is made or such higher rate as FMPA determines appropriate.

Aggregate Debt Service for any period means, as of any date of calculation, the sum of the amounts of Debt Service for such period with respect to all Series and all Parity Debt; provided, however, that for purposes of calculating or estimating Aggregate Debt Service for any future period (except as otherwise specifically provided in the Resolution): (A) any Variable Interest Rate Bonds shall be deemed to bear interest at all times prior to the maturity date thereof for which the interest rate payable thereon has not yet been determined at the Estimated Average Interest Rate applicable thereto; (B) any Bonds, other than Variable Interest Rate Bonds, in respect of which FMPA has entered into a Qualified Swap shall during the period for which such Qualified Swap is in effect be deemed to bear interest at the highest of the fixed rate or the maximum interest rate payable on such Bonds or pursuant to such Qualified Swap; (C) any Put Bonds Outstanding during such period which by their terms are not required to be paid by FMPA upon tender by the Holder thereof shall be assumed to mature on the stated maturity date thereof; (D) any Put Bonds Outstanding during such period which by their terms are required to be paid by FMPA upon tender by the Holder thereof shall be assumed to mature on the earliest to occur of (1) the stated maturity date thereof, (2) the date provided in an applicable Supplemental Resolution, or (3) if the Bond Support Facility securing such Put Bonds expires

FMPA-POD3-00075

HEARING EXHIBIT - 00000485

within six months or fewer of the date of calculation and has not been renewed or replaced, the expiration date of such Bond Support Facility; (E) the principal amount of any Put Bonds tendered for payment by FMPA which are required to be paid by FMPA which have not yet been purchased in lieu of such payment by FMPA shall be deemed to mature on the date required to be paid pursuant to such tender; and (F) subject to the provisions of the Supplemental Resolution authorizing any Extendible Maturity Bonds, Extendible Maturity Bonds Outstanding during such period shall be deemed to mature on the later of the stated maturity date or the date to which such stated maturity date has been extended.

Annual Budget shall mean the annual budget, as amended or supplemented, adopted or in effect for a particular Fiscal Year as provided in the Resolution.

Bond or Bonds shall mean any bond or bonds, note or notes, or other evidences of indebtedness (other than Subordinated Debt), as the case may be, authenticated and delivered under and pursuant to the Resolution.

Bond Series Certificate means a certificate of an Authorized Officer of FMPA fixing terms, conditions and other details of the Bonds or Parity Debt, in accordance with the delegation of power to do so under a Supplemental Resolution.

Bond Support Facility means any irrevocable letter of credit, standby bond purchase agreement, line of credit, policy of bond insurance, surety bond, guarantee or similar instrument which is obtained by FMPA and is issued by a financial, insurance or other institution and which provides security or liquidity in respect of the Bonds of any Series (and with respect to a policy of bond insurance guarantees the payment of principal of and interest on the Bonds), not including any Reserve Account Credit Facility.

Business Day means any day that is not a Saturday, Sunday or legal holiday in the State of Florida or a day on which banks in New York City are authorized by law or executive order to close.

Contingency Requirement shall mean, at any date of calculation, with respect to the Contingency Account in the Reserve and Contingency Fund, such amount as at the date of calculation shall have been established by FMPA as the Contingency Requirement in its Annual Budget which is then in effect.

Cost of Acquisition and Construction means all costs, expenses and liabilities of FMPA related to the All-Requirements Power Supply Project or the System which on the date hereof or in the future shall be permitted to be funded with the proceeds of Bonds pursuant to the provisions of the Act or any other applicable laws of the State of Florida.

Credit Facility shall mean an irrevocable letter of credit, surety bond, loan agreement, Standby Purchase Agreement or other agreement, facility or insurance or guaranty arrangement issued or extended by a bank, a trust company, a national banking association, an organization subject to registration with the Board of Governors of the Federal Reserve System under the Bank Holding Company Act of 1956 or any successor provisions of law, a federal branch pursuant to the International Banking Act of 1978 or any successor provisions of law, a savings bank, a saving and loan association, an insurance company or association chartered or organized under the laws of any state of the United States of America, the Government National Mortgage Association or any successor thereto, the Federal National Mortgage Association or any successor thereto, or any other federal agency or instrumentality approved by FMPA, pursuant to which FMPA is entitled to obtain monies to pay the principal, purchase price or Redemption Price of Bonds due in accordance with their terms or tendered for purchase or redemption, plus accrued interest thereon to the date of payment, purchase or redemption thereof in accordance with the Resolution, whether or not FMPA is in default under the Resolution.

Debt Service for any period shall mean, as of any date of calculation and with respect to any Series or any Parity Debt, an amount equal to the sum of (i) interest accruing during such period on Bonds of such Series and all additional interest amounts to accrue to the end of such period pursuant to any related Parity Debt, except to the extent that such interest is to be paid from deposits made from Bond proceeds into the Debt Service Account in the Debt Service Fund (including amounts, if any, transferred thereto from the Construction Fund), and (ii) that portion of each Principal Installment for such Series and such Parity Debt which would accrue during such period if such Principal Installment were deemed to accrue daily in equal amounts from the next preceding Principal Installment due date for such Series and such Parity Debt (or, if there shall be no such preceding Principal Installment due date, from a date one year preceding the due date of such Principal Installment or from the date of issuance of the Bonds of such Series and such Parity Debt, whichever date is later). Such interest and Principal Installments for such Series shall be calculated on the assumption that (x) no Bonds (except for Put Bonds actually tendered for payment or for purchase in accordance with the Supplemental Resolution authorizing the Series of Bonds of which such Bond is one prior to the stated maturity thereof and not purchased or remarketed on the date required to be paid or purchased) of such Series Outstanding at the date of calculation will cease to be Outstanding except by reason of the payment of each Principal Installment on the due date thereof and (y) the principal amount of Put Bonds tendered for payment before the stated maturity thereof shall be deemed to accrue on the date required to be paid pursuant to such tender.

FMPA-POD3-00076

HEARING EXHIBIT 00000486

Debt Service Reserve Requirement shall mean, with respect to a particular Series of Bonds, the amount, if any, set forth in the Supplemental Resolution authorizing such Series of Bonds. Any amounts on deposit in the Debt Service Reserve Account for such Bonds shall, unless otherwise provided in the Supplemental Resolution authorizing such Bonds, secure only such Outstanding Bonds (and related Parity Reimbursement Obligations) and shall not be available to pay Debt Service on any other Bonds from time to time Outstanding hereunder.

Extendible Maturity Bonds shall mean Bonds the maturities of which, by their terms, may be extended by and at the option of the Holder thereof.

Net Revenues for any period means the Revenues during such period, determined on an accrual basis, plus (x) the amounts, if any, transferred from the Rate Stabilization Account in the Operation and Maintenance Fund into the Revenue Fund during such period and minus (y) the sum of (a) Operation and Maintenance Expenses during such period, determined on an accrual basis, to the extent paid or to be paid from Revenues and (b) the amounts, if any, accrued in the Revenue Fund for transfer to the Rate Stabilization Account in the Operation and Maintenance Fund during such period.

Option Bonds shall mean both Extendible Maturity Bonds and Put Bonds.

Put Bonds shall mean Bonds which by their terms may be tendered by and at the option of the Holder thereof for payment by FMPA or purchase and remarketing prior to the stated maturity or redemption date thereof either (a) by FMPA and by the Person and/or from the source specified in a Supplemental Resolution or (b), without recourse to FMPA by the Person and/or from the source specified in a Supplemental Resolution; provided, however, that such payment by FMPA shall in all events be required to be supported by a Bond Support Facility.

Refundable Principal Installment means any Principal Installment for any Series of Bonds which FMPA intends to pay with monies which are not Revenues, provided that such intent shall have been expressed in the Supplemental Resolution authorizing such Series of Bonds and provided further that such Principal Installment shall be a Refundable Principal Installment only through the first day of the twelfth month preceding the month in which such Principal Installment comes due or such earlier time as FMPA no longer intends to pay such Principal Installment with monies which are not Revenues.

Revenues shall mean (i) all revenues, income, rents, user fees or charges and receipts derived by FMPA from or attributable to the ownership and operation of the System, including all revenues attributable to the System or to the payment of the costs thereof received by FMPA under any contract for the sale of power, energy, transmission, dispatching or other service from the System or any part thereof or any contractual arrangement with respect to the use of the System or any portion thereof or the services, output or capacity thereof, (ii) the proceeds of any insurance covering business interruption loss relating to the System and (iii) interest received on any monies or securities held pursuant to the Resolution and paid or required to be paid into the Revenue Fund. Revenues shall not include any amounts paid to FMPA pursuant to a Qualified Swap or similar financial arrangements.

System means all items of real and personal property, all interests in or rights to the use of services, output or capacity acquired or purchased by FMPA for the purposes of, or designated by FMPA to be used for the purpose of, meeting its obligations under the All-Requirements Power Supply Contracts, which now or in the future shall be permitted to be included in the System pursuant to the provisions of the Act or other applicable laws of the State of Florida. Unless otherwise provided by action of the Agency designating such items as part of the System, the System shall not include FMPA's 8.806% undivided ownership interest in St. Lucie Unit No. 2, or any rights to receive any electric capacity or energy therefrom; any rights to receive electric capacity and energy pursuant to the St. Lucie Nuclear Reliability Exchange Agreement, dated March 26, 1982, as amended, or the St. Lucie Replacement Power Agreement, dated February 11, 1982; or FMPA's 14.8193% undivided ownership interest in Stanton Unit No. 1 acquired pursuant to the Stanton Unit No. 1 Participation Agreement dated as of January 16, 1984, as amended (the "Stanton Project"); or FMPA's 5.3012% undivided ownership interest in Stanton Unit No. 1 acquired pursuant to Stanton Unit No. 1 Participation Agreement dated as of March 22, 1985, as amended (the "Tri-City Project"); provided, however, that certain Project Participants having Entitlement Shares in the Tri-City and/or Stanton Projects have agreed to sell and make available to FMPA for the All-Requirements Power Supply Project, the capacity and energy from such Entitlement Shares pursuant to the Capacity and Energy Sales Contracts between FMPA and such Project Participants and the right to receive such capacity and energy shall be a part of the System. Notwithstanding the foregoing definition of the term System, such term shall not include any properties, rights or interests in properties of FMPA which FMPA determines will not constitute a part of the All-Requirements Power Supply Project or the System for the purposes of the All-Requirements Power Supply Project Contracts.

Trust Estate shall mean (i) the proceeds of the sale of Bonds, (ii) all right, title and interest of FMPA in, to and under the All-Requirements Power Supply Project Contracts, (iii) the Revenues and (iv) all Funds established by the Resolution

HEARING EXHIBIT - 00000487

(other than the Decommissioning Fund) including the investments, if any, thereof, and the same are hereby pledged and assigned, subject only to the provisions of the Resolution permitting the application thereof for the purposes and on the terms and conditions set forth in the Resolution.

Pledge

The Bonds and any Parity Debt shall be special obligations of FMPA payable solely from and secured as to the payment of the principal and Redemption Price thereof, and interest thereon, in accordance with their terms and the provisions of the Resolution solely by the Trust Estate.

Application Of Revenues

Revenues are pledged by the Resolution to payment of principal and redemption price of and interest on the Bonds, subject to the provisions of the Resolution permitting application thereof for other purposes. The Resolution establishes the following Funds and Accounts:

Funds	Held by:
Construction Fund	Trustee
Revenue Fund	FMPA
Operation and Maintenance Fund	FMPA
Operation and Maintenance Account	
Working Capital Account	
Rate Stabilization Account	
Debt Service Fund	Trustee
Debt Service Account	
Debt Service Reserve Account	
Subordinated Debt Fund	Held as determined by the Supplemental Resolution
Reserve and Contingency Fund	FMPA
Renewal and Replacement Account	
Contingency Account	
General Reserve Fund	FMPA

Pursuant to the Resolution, all Revenues are to be deposited promptly by FMPA upon receipt thereof into the Revenue Fund. Each month, amounts in the Revenue Fund are to be paid to the following Funds in the order of priority for application therefrom as follows:

- To the credit of the Operation and Maintenance Account, the Working Capital Account and the Rate Stabilization Account in the Operation and Maintenance Fund, the respective amounts which are equal to (i) in respect to the Operation and Maintenance Account, the amount required so that the balance credited to such Account shall equal the amount estimated to be necessary for the payment of Operation and Maintenance Expenses for the next succeeding calendar month and (ii) in respect to the Working Capital Account and the Rate Stabilization Account, the amount required so that the balance credited to such Accounts equals the monies budgeted to be on credit to said Accounts in the Annual Budget for the next succeeding calendar month. Amounts credited to the Operation and Maintenance Account will be applied by FMPA to the payment of Operation and Maintenance Expenses. Amounts credited to the Working Capital Account shall, at the direction of FMPA, (i) be credited to the Operation and Maintenance Account, (ii) be applied directly to any of the purposes for which amounts in the Operation and Maintenance Account could be applied, (iii) to the extent provided in the current Annual Budget, be transferred to the Debt Service Account, or (iv) to the extent that such amounts were not credited thereto from the proceeds of the Bonds, be credited to the Reserve and Contingency Fund or to the Decommissioning Fund, if then created. Amounts credited to the Rate Stabilization Account shall, at the direction of FMPA, (i) to the extent provided in the current Annual Budget, be credited to or transferred to, as appropriate, any other Fund or Account held under the Resolution, (ii) be applied to make up deficiencies in the Debt Service Account and the Debt Service Reserve Account except deficiencies in the Debt Service Reserve Account due to transfers to the Debt Service Account, (iii) be paid to each Reserve Account Credit Facility Provider to reimburse such provider for any amounts advanced under its Reserve Account Credit Facility, (iv) be applied to make up deficiencies in the Debt Service Reserve Account due to transfers to the Debt Service Account, and (v) be applied to make up deficiencies in the Renewal and Replacement Account and the Contingency Account. The Resolution provides for the application of excess amounts in the Operation and Maintenance Account to make up any deficiencies in certain other Funds established under the Resolution, with any

FMPA-POD3-00078
HEARING EXHIBIT - 00000488

balance to be deposited in the General Reserve Fund. The determination of the amounts and application of any such excess amounts shall be made by FMPA.

- For deposit into the Debt Service Account in the Debt Service Fund, the amounts required so that the balance (excluding capitalized interest on deposit therein in excess of the amount thereof to be applied to pay interest accrued and to accrue on all outstanding Bonds to the end of the then current calendar month) in said Account equals the Accrued Aggregate Debt Service as of the last day of the then current calendar month or, if interest and/or principal are required to be paid to Holders of Bonds during the next succeeding calendar month on a day other than the first day of such calendar month, Accrued Aggregate Debt Service as of the day through and including which such interest and/or principal is required to be paid. The Trustee will apply amounts in the Debt Service Account to the payment of principal of and interest on the Bonds.

With respect to amounts accumulated in the Debt Service Account with respect to any Sinking Fund Installments, the Trustee may, and if directed by FMPA, shall apply such amounts on or prior to the 40th day preceding the due date of such Sinking Fund Installment to (i) the purchase of Bonds of the Series, maturity and interest rate within each maturity for which such Sinking Fund Installment was established or (ii) the redemption at the applicable Redemption Price of such Bonds.

- To reimburse each Reserve Account Credit Facility Provider for any amounts advanced under its Reserve Account Credit Facility, including paying interest thereon, in accordance with the terms of such Reserve Account Credit Facility and any reimbursement agreement between FMPA and the Reserve Account Credit Facility Provider; to the extent that on any date the amounts available for such reimbursement payments are insufficient to make all such payments, including interest, the amounts actually available shall be paid pro rata, to each Reserve Account Credit Facility Provider in proportion to the payments then due under the respective Reserve Account Credit Facilities; provided, however, that if any such payment shall not result in the reinstatement of a portion of such Reserve Account Credit Facility in an amount equal to such payment (excluding the portion thereof representing interest on such advance), such reimbursement payment shall be made only after the payments otherwise required by the Resolution.

- To the credit of each subaccount in the Debt Service Reserve Account, the amount, if any, required for such subaccounts to equal the Debt Service Reserve Requirement as of the last day of the current calendar month.

Amounts in the Debt Service Reserve Account are to be applied to make up any deficiency in the Debt Service Account. Whenever the amount in the Debt Service Reserve Account, together with the amount in the Debt Service Account, is sufficient to pay in full all outstanding Bonds in accordance with their terms, the funds on deposit in the Debt Service Reserve Account will be transferred to the Debt Service Account. Whenever monies on deposit in the Debt Service Reserve Account exceed the Debt Service Reserve Requirement, the excess may, if requested by FMPA, be deposited in the Revenue Fund.

- To the Subordinated Debt Fund, the amount, if any, required by the Supplemental Resolution authorizing such issue to pay principal or sinking fund installments of and premiums, if any, and interest on each issue of Subordinated Debt and reserves therefor. FMPA will apply amounts in the Subordinated Debt Fund in accordance with the Supplemental Resolution authorizing the issue. If at any time the amount in the Debt Service Account in the Debt Service Fund is deficient or the amount in the Debt Service Reserve Account is less than the Debt Service Reserve Requirement as a result of a transfer to the Debt Service Account, and there are no available monies sufficient to cure such deficiency in the Reserve and Contingency Fund or the General Reserve Fund, amounts in the Subordinated Debt Fund will be applied to make up such deficiency.

- To the credit of the Reserve and Contingency Fund, for credit to (i) the Renewal and Replacement Account, the amount, if any, budgeted for credit therein during such month in the then current Annual Budget, and (ii) the Contingency Account, the amount, if any, required for such Account to equal the Contingency Requirement.

Amounts in the Renewal and Replacement Account will be applied to the payment of Development Costs and costs of renewals, replacements, repairs, additions, betterments, enlargements and improvements to the System necessary to keep the same in good operating condition or to prevent a loss of Revenues therefrom, or required by any governmental agency having jurisdiction over the System or any part thereof.

Amounts in the Contingency Account will be applied to the payment of costs of major renewals, replacements, repairs, additions, betterments, enlargements and improvements with respect to the System and to the payment of Development Costs, in each case to the extent that amounts credited to the Renewal and Replacement Account are insufficient.

FMPA-POD3-00079

HEARING EXHIBIT - 00000489

If at any time the amount in the Debt Service Account is deficient or the amount in the Debt Service Reserve Account is less than the Debt Service Reserve Requirement as a result of a transfer to the Debt Service Account, and there are not on deposit in the General Reserve Fund available monies sufficient to cure such deficiency, then FMPA will transfer from the Reserve and Contingency Fund the amount necessary to make up such deficiency.

Amounts in the Renewal and Replacement Account and the Contingency Account which exceed the respective amounts required to be held therein, to the extent not required to make up deficiencies in the Debt Service Fund may be deposited in the Decommissioning Fund, if established, or, in the General Reserve Fund.

- To the credit of the General Reserve Fund, the balance, if any, in the Revenue Fund; FMPA will transfer from the General Reserve Fund amounts in the following order of priority: (i) to the Debt Service Account and the Debt Service Reserve Account in the Debt Service Fund the amount necessary to make up any deficiencies in payments to said Accounts except deficiencies in the Debt Service Reserve Account due to transfers to the Debt Service Account (ii) to the Debt Service Reserve Account the amount of any deficiency in such Account resulting from any transfer to the Debt Service Account, and (iii) to the Renewal and Replacement Account and the Contingency Account in the Reserve and Contingency Fund, in that order, the amount necessary to make up any deficiencies in payments to said Fund.

Amounts in the General Reserve Fund not required for any of the above purposes shall upon determination of FMPA be applied to or set aside by FMPA for any one or more of the following: (i) the purchase or redemption of Bonds, and expenses and reserves in connection therewith; (ii) payment of Operation and Maintenance Expenses or credit to the Working Capital Account in the Operation and Maintenance Fund; (iii) payments into any separate accounts established in the Construction Fund; (iv) transfer to the credit of the Renewal and Replacement Account or the Contingency Account in the Reserve and Contingency Fund; (v) transfer to the Subordinated Debt Fund; (vi) transfer to the Rate Stabilization Account in the Operation and Maintenance Fund; (vii) payments of any termination or other fees, expenses, indemnification or other obligations to a Qualified Swap Provider; and (viii) any other lawful purpose of FMPA related to the System.

Debt Service Reserve Account

In lieu of the required deposits and transfers to any subaccount in the Debt Service Reserve Account, FMPA may at any time cause to be deposited into such subaccount for the benefit of the holders of the Bonds and any related Parity Reimbursement Obligations, an insurance policy or a letter of credit in an amount equal to the difference between the Debt Service Reserve Requirement and the sums, if any, then on deposit in such subaccount or being deposited in such subaccount concurrently with such insurance policy or letter of credit. The insurance policy or letter of credit shall be payable (upon the giving of notice as required thereunder) on any date on which monies will be required to be withdrawn from the subaccount and applied to the payment of a Principal Installment of or interest on any Bonds and any related Parity Debt entitled to the benefit of such amounts in such subaccount and such withdrawal cannot be met by amounts on deposit in such subaccount. The insurer providing such insurance policy shall be a municipal bond or other insurance company, obligations insured by which are rated in one of the two highest rating categories by each nationally recognized rating agency then rating any Series of Bonds at the request of FMPA. The letter of credit issuer shall be a bank or savings and loan association whose long-term uncollateralized debt obligations are rated in either of the two highest rating categories by each nationally recognized rating agency then rating any Series of Bonds at the request of FMPA. If a disbursement is made pursuant to an insurance policy or a letter of credit, FMPA shall be obligated either (i) to reinstate the maximum limits of such insurance policy or letter of credit or (ii) to deposit into the appropriate subaccount in the Debt Service Reserve Account, funds in the amount of the disbursement made under such insurance policy or letter of credit, or a combination of such alternatives, as shall provide that the amount in such subaccount equals the Debt Service Reserve Requirement.

In the event of the refunding of any Bonds, the Trustee shall, if FMPA so directs, withdraw from the related subaccount in the Debt Service Reserve Account in the Debt Service Fund all, or any portion of, the amounts accumulated therein with respect to the Bonds being refunded and deposit such amounts with itself as Trustee to be held for the payment of the principal or Redemption Price, if applicable, and interest on the Bonds being refunded; provided that such withdrawal shall not be made unless (a) immediately thereafter the Bonds being refunded shall be deemed to have been paid pursuant to the provisions of the Resolution, and (b) the amount remaining in the related subaccount, after giving effect to the issuance of the Refunding Bonds and the disposition of the proceeds thereof and to any insurance policy or letter of credit deposited in such subaccount, shall not be less than the Debt Service Reserve Requirement. In the event of such refunding, FMPA may also direct the Trustee to withdraw from the related subaccount all, or any portion of, the amounts accumulated therein with respect to Debt Service on the Bonds being refunded and deposit such amounts in any Fund or Account under the Resolution; provided, however, that such withdrawal shall not be made unless items (a) and (b) referred to hereinabove have been satisfied and provided, further, at the time of withdrawal, there shall exist no deficiency in any Fund or Account held under the Resolution.

FMPA-POD3-00080

HEARING EXHIBIT - 00000490

Construction Fund

The Resolution establishes a Construction Fund, to be held by the Trustee, into which will be paid amounts required by the provisions of the Resolution and any Supplemental Resolution and, at the option of FMPA, any monies received for or in connection with the System by FMPA from any other source, unless required to be otherwise applied as provided in the Resolution. In addition, subject to the provisions of any agreements relating to the purchase, ownership or operation of any part of the System, proceeds of insurance for physical loss of or damage to the System or of contractors' performance bonds with respect thereto pertaining to the period of construction will be paid into the Construction Fund.

The Trustee will pay to or for the account of FMPA, upon the requisitions of FMPA therefor pursuant to the Resolution, from the Construction Fund, the Cost of Acquisition and Construction of the System. The Trustee will pay to FMPA, upon the requisition therefor, a sum or sums aggregating not more than $10,000,000 to be used by FMPA to establish a revolving fund to pay Costs of Acquisition and Construction which cannot conveniently be paid through the requisition process.

To the extent that other monies are not available therefor, amounts in the Construction Fund will be applied to the payment of principal of and interest on Bonds when due.

Bonds Other than Refunding Bonds

FMPA may issue Bonds for the purpose of paying all or a portion of the Cost of Acquisition and Construction of the System.

Refunding Bonds

One or more Series of Refunding Bonds may be issued to refund any Outstanding Bonds or Parity Debt. The issuance of Refunding Bonds to refund Outstanding Bonds is subject to the receipt by the Trustee of, among other things, a certificate of an Authorized Officer of FMPA stating that such Refunding Bonds are being issued to reduce amounts payable under the All-Requirements Power Supply Project Contracts or that the issuance of such Refunding Bonds is otherwise advantageous to FMPA or the Project Participants.

Investment Of Certain Funds

The Resolution provides that certain funds and accounts held thereunder may, and in the case of the Debt Service Account and the Debt Service Reserve Account in the Debt Service Fund and of the Subordinated Debt Fund must be invested to the fullest extent practicable in Investment Securities. The Resolution provides that such investments will mature no later than such times as necessary to provide monies when needed for payments from such Funds and Accounts. "Investment Securities" are defined in the Resolution to mean and include any of the following securities, if and to the extent the same are at the time legal for investment of FMPA's funds:

(i) any bonds or other obligations which as to principal and interest constitute direct obligations of, or are unconditionally guaranteed by, the United States of America, including obligations of any of the Federal agencies set forth in clause (iii) below to the extent unconditionally guaranteed by United States of America;

(ii) any bonds or other obligations of any state of the United States of America or of any agency, instrumentality or local governmental unit of such state (a) which are not callable prior to maturity or as to which irrevocable instructions have been given to the trustee of such bonds or other obligations by the obligor to give due notice of redemption and to call such bonds for redemption on the date or dates specified in such instructions, (b) which are secured as to principal and interest and redemption premium, if any, by a fund consisting only of cash or bonds or other obligations of the character described in clause (i) hereof which fund may be applied only to the payment of such principal of and interest and redemption premium, if any, on such bonds or other obligations on the maturity date or dates thereof or the redemption date or dates specified in the irrevocable instructions referred to in subclause (a) of this clause (ii), as appropriate, and (c) as to which the principal of and interest on the bonds and obligations of the character described in clause (i) hereof which have been deposited in such fund along with any cash on deposit in such fund are sufficient to pay principal of and interest and redemption premium, if any, on the bonds or other obligations described in this clause (ii) on the maturity date or dates thereof or on the redemption date or dates specified in the irrevocable instructions referred to in subclause (a) of this clause (ii), as appropriate;

(iii) bonds, debentures, or other evidences of indebtedness issued or guaranteed by any agency or corporation which has been or may hereafter be created pursuant to an Act of Congress as an agency or instrumentality of the United States of America;

HEARING EXHIBIT - 00000491

(iv) New Housing Authority Bonds issued by public agencies or municipalities and fully secured as to the payment of both principal and interest by a pledge of annual contributions under an Annual Contributions Contract or Contracts with the United States of America; or Project Notes issued by public agencies or municipalities and fully secured as to the payment of both principal and interest by a requisition or payment agreement with the United States of America;

(v) direct and general obligations of any state of the United States of America or any agency, instrumentality or local governmental unit of any such state, to the payment of the principal of and interest on which the full faith and credit of such state, agency, instrumentality or local governmental unit is pledged, provided that at the time of their purchase under the Resolution such obligations are rated in either of the two highest categories by a nationally recognized bond rating agency;

(vi) obligations of any state of the United States of America or any political subdivision thereof or any agency or instrumentality of any state or political subdivision which shall be rated in the highest rating category by a nationally recognized bond rating agency;

(vii) certificates or other instruments that evidence ownership of the right to payments of principal of or interest on obligations of any state of the United States of America or any political subdivision thereof or any agency or instrumentality of any state or political subdivision, provided that such obligations shall be held in trust by a bank or trust company or a national banking association meeting the requirements for a successor Trustee in accordance with the Resolution, and provided further that the payments of all principal of and interest on such certificates or such obligations shall be fully insured or unconditionally guaranteed by, or otherwise unconditionally payable pursuant to a credit support arrangement provided by, one or more financial institutions or insurance companies or associations which at the date of investment shall have an outstanding, unsecured, uninsured and unguaranteed debt issue rated in the highest rating category by a nationally recognized bond rating agency, or, in the case of an insurer providing municipal bond insurance policies insuring the payment, when due, of the principal of and interest on municipal bonds, such insurance policy shall result in such municipal bonds being rated in the highest rating category by a nationally recognized bond rating agency;

(viii) certificates that evidence ownership of the right to payments of principal or interest on obligations described in clause (i), provided that such obligations shall be held in trust by a bank or trust company or a national banking association meeting the requirements for a successor Trustee in accordance with the Resolution;

(ix) certificates of deposit, whether negotiable or non-negotiable, and banker's acceptances of the 50 largest banks in the United States or commercial paper issued by the parent holding company of any such bank which at the time of investment has an outstanding unsecured, uninsured and unguaranteed debt issue ranked in either of the two highest rating categories by a nationally recognized bond rating agency (including the Trustee and its parent holding company, if any, if it otherwise qualifies);

(x) commercial paper, other than that issued by bank holding companies, (1) rated at the date of investment in the highest rating category by a nationally recognized bond rating agency, or (2) issued by United States corporations which at the date of investment have an outstanding, unsecured, uninsured and unguaranteed debt issue rated in either of the two highest rating categories by a nationally recognized bond rating agency;

(xi) any repurchase agreement with any bank or trust company organized under the laws of any state of the United States of America or any national banking association or government bond dealer reporting to, trading with, and recognized as a primary dealer by the Federal Reserve Bank of New York, which agreement is secured by any one or more of the securities described in clauses (i), (iii), (iv), (ix), or (x) above, which securities shall at all times have a market value (exclusive of accrued interest) not less than the full amount of the repurchase agreement, and be delivered to another bank or trust company organized under the laws of any state of the United States of America or any national banking by association, as custodian in the name of or for exclusive benefit of FMPA;

(xii) shares of an Investment Company, organized under the Investment Company Act of 1940 as amended, which invests its assets exclusively in obligations of the type described in clause (i), (vi), (ix), (x), or (xi) above;

(xiii) Local Government Surplus Trust Fund of the State of Florida;

(xiv) Certificates of deposit, whether negotiable or non-negotiable, and banker's acceptance of the 10 largest banks in the State of Florida measured in terms of their primary capital (i.e., equity minus reserves);

HEARING EXHIBIT 00000492

(xv) Money market funds rated in the highest category for comparable types of obligations by each Rating Agency then maintaining a rating on the Bonds at the request of FMPA;

(xvi) investment agreements or guaranteed investment contracts with any financial institution whose senior long-term debt obligations or whose obligations under such investment agreement or guaranteed investment contract are guaranteed by a financial institution whose senior long-term debt obligations have a rating (at the time such agreement or contract is entered into) one of the two highest rating categories for comparable types of obligations by each Rating Agency then maintaining a rating on the Bonds at the request of FMPA ; and

(xvii) any other investment in which the Issuer is authorized from time to time to invest under applicable law with respect to which an Authorized Officer of FMPA has, on or before the date thereof, delivered to the Trustee (A) a certificate to the Trustee designating the additional investment as an Investment Security and (B) a Rating Confirmation.

Interest (net of the return of accrued interest paid in connection with the purchase of any investment) earned on any monies or investments in such Funds or Accounts, other than the Construction Fund, shall be paid into the Revenue Fund. Interest on monies or investments in the Construction Fund shall be held in such Fund for the purposes thereof.

The Trustee and FMPA may deposit monies in all Funds and Accounts held by it under the Resolution in banks or trust companies organized under the laws of any state of the United States or national banking associations having capital stock, surplus and undivided earnings of $50,000,000 or more ("Depositories"). All monies held under the Resolution by the Trustee, FMPA or any Depository must be either (i) fully insured by the Federal Deposit Insurance Corporation, or (ii) continuously and fully secured by lodging with the Trustee or FMPA, as custodian, as collateral security, such securities as are described in clauses (i) through (iv), inclusive or in clause (viii), of the definition of "Investment Securities" having a market value not less than the amount of such monies, and secured in such other manner as may then be required by applicable Federal or State of Florida laws and regulations and applicable state laws and regulations of the state in which the Trustee, FMPA or such Depository is located; provided, however, that, to the extent permitted by law, it will not be necessary for the Trustee or any Paying Agent to give security for the deposit of any monies held in trust by it and set aside for the payment of the principal of, Redemption Price of, or interest on any Bonds, or for the Trustee, FMPA or any Depository to give security for any monies ich are represented by obligations or certificates of deposit purchased as an investment of such monies.

Creation of Liens

FMPA will not issue any bonds, notes, debentures or other evidences of indebtedness of a similar nature, other than the Bonds and Parity Debt, payable out of or secured by a security interest in or pledge or assignment of the Trust Estate or other monies, securities or funds held or set aside under the Resolution, nor will it create or cause to be created any lien or charge thereon; provided, however, to the extent permitted by law, FMPA may issue (a) bond anticipation notes, (b) evidences of indebtedness (i) payable out of monies in the Construction Fund as part of the Cost of Acquisition and Construction or (ii) payable out of, or secured by a security interest in a pledge and assignment of, Revenues to be received after the discharge of the pledge of Revenues provided in the Resolution or (c) Subordinated Debt.

Rate Covenant

FMPA covenants that it will fix, establish, maintain and collect rents, rates, fees and charges under the All-Requirements Power Supply Project Contracts and shall otherwise charge and collect rents, rates, fees and charges for the use or the sale of the output, electric capacity and energy or service of the System which, together with other available Revenues, are reasonably expected to yield Net Revenues for the 12-month period commencing with the effective date of such rents, rates and charges which shall be equal to at least the Aggregate Debt Service for such period and, in any event, as shall be required, together with other available funds, to pay or discharge all other indebtedness, charges and liens whatsoever payable out of Revenues under the Resolution; provided, however, that any Principal Installment which is a Refundable Principal Installment may be excluded from Aggregate Debt Service for purposes of the foregoing but only to the extent that FMPA intends to pay such Principal Installment from sources other than Revenues. Promptly upon (a) any material decrease in any month in the Revenues anticipated to be produced by any rents, rates or charges at the time of adoption of such rents, rates or charges or any later review thereof, (b) any material increase in expenses of operation of the System on any month not contemplated at the time of adoption of the rents, rates and charges then in effect or any later review thereof, or (c) any other material change in the circumstances which were contemplated at the time such rents, rates and charges were most recently reviewed, but not less quently than once every 12 months, FMPA shall review the rents, rates, fees and charges so established and shall promptly ...ablish or revise such rents, rates, fees and charges as necessary to comply with the foregoing requirements, provided that such rents, rates, fees and charges shall in any event produce monies sufficient to enable FMPA to comply with all its covenants under the Resolution.

HEARING EXHIBIT - 00000493

In estimating Aggregate Debt Service on any Variable Rate Bonds for the purposes of the foregoing paragraph, FMPA shall be entitled to assume that such Variable Rate Bonds will bear such interest rate or rates as FMPA shall determine; provided, however, that the interest rate or rates assumed shall not be less than the interest rate borne by such Variable Rate Bonds at the time such estimate is made.

Covenants with Respect to All-Requirements Power Supply Project Contracts

FMPA covenants that it will collect and cause to be deposited in the Revenue Fund all amounts payable to it under the All-Requirements Power Supply Project Contracts or payable to it pursuant to any other contract for the sale or the use of output, capacity, or other service from the System. FMPA will enforce the provisions of the All-Requirements Power Supply Project Contracts and duly perform its covenants and agreements thereunder. FMPA will not consent to any rescission of, or amendment to, or take any action under or in connection with, the All-Requirements Power Supply Contracts unless it complies with the requirements in the Resolution.

Annual Budget

FMPA will file with the Trustee an Annual Budget for each Fiscal Year. The Annual Budget will include monthly appropriations for the estimated Operation and Maintenance Expenses and other expenditures for the System for such year, monthly appropriations for the estimated amount to be credited during each month to the Rate Stabilization Account, the Operation and Maintenance Account and the Working Capital Account in the Operation and Maintenance Fund, and the estimated amount to be credited during each month in the Renewal and Replacement Account and the Contingency Account in the Reserve and Contingency Fund and the Decommissioning Fund, if established, and the requirements, if any, for and the amounts estimated to be expended during each month from each Fund and Account. FMPA shall review quarterly, and at such other times as it deems desirable, its estimates set forth in the Annual Budget and in the event such estimates do not substantially correspond with actual Revenues, Operation and Maintenance Expenses or other requirements, or if there are extraordinary expenses, FMPA shall prepare an amended Annual Budget for the remainder of such fiscal year. FMPA may also at any time adopt an amended Annual Budget for the remainder of the then current Fiscal Year.

Insurance

FMPA will use its best efforts to keep or cause to be kept the properties of the System which are of an insurable nature and of the character usually insured by those operating properties similar to the System and in which FMPA has an insurable interest insured against loss or damage by fire and from other causes customarily insured against and in such relative amounts as are usually obtained. FMPA will at all times use its best efforts to maintain or cause to be maintained insurance or reserves against loss or damage from such hazards and risks to the person and property of others as are usually insured or reserved against by those operating properties similar to the properties of the System. FMPA will only be required to obtain such insurance if the same is available at reasonable rates and upon reasonable terms and conditions but if such insurance is not so obtainable, FMPA shall deliver an opinion to the Trustee of an independent insurance consultant to that effect.

Accounts and Reports

FMPA will keep or cause to be kept proper and separate books of records and accounts relating to the System, the Funds and Accounts established under the Resolution and relating to costs and charges under the All-Requirements Power Supply Project Contracts. Such books, together with all contracts and all other books and papers of FMPA relating to the System, will at all times be subject to the inspection of the Trustee and the holders of not less than 5% in principal amount of Bonds then outstanding.

FMPA will file annually with the Trustee and the Consulting Engineer an annual report, accompanied by an accountant's certificate, relating to the financial position of the System, statements of assets and liabilities, statements of Revenues and Operation and Maintenance Expenses, a summary with respect to Funds and Accounts established under the Resolution of the changes in financial condition during such year, and a statement as to the existence of any default under the provisions of the Resolution.

FMPA will notify the Trustee forthwith of any Event of Default or default in the performance by FMPA of any covenant, agreement or condition of the Resolution. FMPA will file annually with the Trustee a certificate stating whether, to the best of the signer's knowledge and belief, FMPA has complied with its covenants and obligations in the Resolution and whether there is then existing any Event of Default or other event which would become an Event of Default upon lapse of time.

The reports, statements and other documents required to be furnished to the Trustee pursuant to provisions of the Resolution will be available for the inspection of holders of the Bonds at the office of the Trustee and will be mailed to each

FMPA-POD3-00084

HEARING EXHIBIT 00000494

holder of the Bonds who files a written request therefor with FMPA. FMPA may charge for such reports, statements and other documents a reasonable fee to cover reproduction, handling and postage.

Amendments and Supplemental Resolutions

Any of the provisions of the Resolution may be amended by FMPA by a supplemental resolution upon the consent (a) if the holders of at least a majority in principal amount of the Bonds outstanding at the time such consent is given and (b) if less than all of the several Series of outstanding Bonds are affected of the holders of at least a majority in principal amount of each Series so affected and outstanding. No such amendment may permit a change in the terms of redemption (including Sinking Fund Installments) or maturity of the principal of any outstanding Bond or any installment of interest thereon or make any reduction in principal amount, redemption price or rate of interest without consent of each affected holder, or reduce the percentages of consents required for a further amendment.

Also, to the extent that all or any portion of Bonds or any Series of Bonds are insured by any nationally recognized company engaged in the business of insuring municipal bonds, such insurance company will be deemed to be the holder of Bonds of any Series as to which it is the insurer at all times for the purpose of giving any approval or consent to the execution and delivery of any supplemental resolution or any amendment, change or modification of the Resolution which requires the written approval or consent of the holders of at least a majority in aggregate principal amount of Bonds of such Series at the time Outstanding.

FMPA may adopt (without the consent of any holders of the Bonds) supplemental resolutions to close the Resolution against, or impose limitations upon, issuance of bonds or other evidences of indebtedness; to add to the covenants and agreements of FMPA in the Resolution; to add to the limitations and restrictions contained in the Resolution; to authorize Bonds of a Series; to authorize, in compliance with all applicable law, Bonds of each Series to be issued in the form of coupon bonds registrable as to principal only or in the form of Bonds issued and held in book-entry form on the books of FMPA or any fiduciary appointed for that purpose by FMPA; to establish for any Series of Bonds a separate subaccount in the Debt Service Reserve Account and make such other amendments to the Resolution necessary or desirable to insure that such Accounts and subaccounts functions in the manner contemplated; to authorize Parity Debt; to authorize Subordinated Debt of a Series; to provide for a Bond Support Facility, Reserve Account Credit Facility, Qualified Swap or other similar arrangement with respect to any Series of Bonds; to reflect the substitution of a new Bond Support Facility or a new Qualified Swap Provider; to confirm any pledge under the Resolution of Revenues or other monies, securities or other funds; to modify any of the provisions of the Resolution provided that such modification is effective only after all Bonds of each Series outstanding at the date of such modification will cease to be outstanding; to add additional Events of Default; to add provisions relating to the application of interest earnings on any Fund or Account under the Resolution required by law to preserve the exemption of interest received on Bonds then Outstanding or to be issued from Federal and/or State income taxation; and to appoint a Trustee. FMPA may adopt (without the consent of any holders of the Bonds but with the consent of the Trustee) supplemental resolutions to cure any ambiguity, supply any omission or cure or correct any defect or inconsistent provision in the Resolution, and to clarify matters or questions arising under the Resolution and not contrary to or inconsistent with the Resolution.

In addition to the purposes described above, FMPA may with the consent of the Trustee but without the consent of Bondholders amend the Resolution to make any amendment or modification which the Trustee, in its sole discretion, determines will not have a material adverse effect on Bondholders.

Notwithstanding anything in the Resolution to the contrary, the consent of the owners of any Series of Bonds to be issued thereunder shall be deemed given if the underwriters or initial purchasers for resale consent in writing to such Supplemental Resolution and the nature of the amendment effected by such Supplemental Resolution is disclosed in the official statement or other offering document pursuant to which such Series of Additional Bonds is offered and sold to the public.

Trustee, Paying Agents

The Resolution requires the appointment by FMPA of one or more Paying Agents (which may include the Trustee). The Trustee may at any time resign on 120 days' written notice to FMPA and may at any time be removed by FMPA with or without cause provided that no Event of Default exists or would exist with notice and/or passage of time. A successor Trustee may be appointed by FMPA, or if FMPA fails to appoint a successor Trustee within 60 days, by the holders of a majority in principal amount of the Bonds then outstanding. Any successor Trustee must be a bank or trust company organized under the laws of any state or a national banking association having capital stock, surplus and undivided earnings aggregating at least 50,000,000 if there be such an entity willing to accept such appointment.

FMPA-POD3-00085

HEARING EXHIBIT - 00000495

Exchange, Transfer and Registry

In all cases in which the privilege of transferring or exchanging the Bonds is exercised, FMPA will execute and the Trustee will authenticate and deliver the Bonds in accordance with the provisions of the Resolution. For every such exchange or transfer of the Bonds, FMPA or the Bond Registrar may make a charge sufficient to reimburse it for any tax, fee or other governmental charge required to be paid with respect to such exchange or transfer. Neither FMPA nor the Bond Registrar will be required to transfer or exchange the Bonds for a period of 15 days next preceding an interest payment date or next preceding any selection of the Bonds to be redeemed or thereafter until after the mailing of any notice of redemption.

Defeasance

The pledge of the Trust Estate, and all covenants, agreements and other obligations of FMPA to the holders of the Bonds under the Resolution will cease, terminate and become void and be discharged and satisfied whenever all Bonds have been paid in full. Bonds will be deemed to have been so paid whenever the following conditions are met: (a) there shall have been deposited with the Trustee either monies in an amount which will be sufficient, or Investment Securities (as defined in the paragraph under the heading "Investments of Certain Funds and Accounts"), the principal of and the interest on which, when due, will provide monies which, together with any monies also deposited with the Trustee, will be sufficient, to pay when due the principal or Redemption Price, if applicable, and interest due or to become due on such Bonds, (b) in the case of Bonds to be redeemed prior to maturity, FMPA has given to the Trustee instructions to mail the notice of redemption therefor, (c) in the event such Bonds are not subject to redemption within the next succeeding 60 days, FMPA has given to the Trustee instructions to mail a notice to the holders of such Bonds that the deposit required by (a) above has been made with the Trustee and that such Bonds are deemed to be paid and stating the maturity or redemption date upon which monies are to be available to pay the principal or redemption price, if applicable, on such Bonds, and (d) all Parity Debt has been repaid in full or payment thereof has been otherwise provided for. The Trustee will, as and to the extent necessary, apply monies held by it as above described to the retirement of said Bonds in amounts equal to the unsatisfied balances of any Sinking Fund Installments with respect to such Bonds, all in the manner provided in the Resolution.

If so directed by FMPA prior to (i) the maturity date of Bonds deemed to have been paid as described in the preceding paragraph which are not to be redeemed prior to their maturity date or (ii) the mailing of the notice referred to in clause (b) above with respect to Bonds deemed to have been paid as described above which are to be redeemed prior to their maturity date, the Trustee is required to apply monies deposited with it in respect of Bonds in accordance with clause (a) above and redeem or sell Investment Securities so deposited with it and apply the proceeds thereof to the purchase of such Bonds and the Bonds so purchased shall be immediately cancelled by the Trustee. No such Bonds shall be purchased unless the monies and the Investment Securities remaining on deposit with the Trustee after such purchase and cancellation would be sufficient to pay when due the Principal Installment or redemption price, if applicable, and interest due, or to become due, on all Bonds in respect to which such monies and Investment Securities are being held by the Trustee. If, at any time prior to the happening of the events described in clauses (i) and (ii) of this paragraph, FMPA shall purchase or otherwise acquire any such Bonds and deliver such Bonds to the Trustee prior to their maturity date or redemption date, as the case may be, the Trustee shall immediately cancel all such Bonds so delivered. In the event that on any interest payment date as a result of any such purchases or deliveries and cancellations of Bonds the total amount of monies and Investment Securities remaining on deposit with the Trustee is in excess of the total amount required to be deposited with the Trustee on such date in respect to the remaining Bonds in order to comply with clause (a) of the first paragraph of this section, the Trustee shall, if requested by FMPA, pay the amount of such excess to FMPA free and clear of the pledge or lien of the Resolution.

For purposes of defeasance, Investment Securities mean (i) only such securities as are described in clause (i), (iv), (vi), (vii) or (viii) of the definition of Investment Securities under the caption "Investment of Certain Funds and Accounts" above which shall not be subject to redemption prior to their maturity other than at the option of the holder thereof; (ii) such securities as are described in clause (ii) of the definition of Investment Securities which shall not be subject to redemption prior to their maturity other than at the option of the Holder thereof or as to which an irrevocable notice of redemption of such securities on a specified redemption date has been given and such securities are not otherwise subject to redemption prior to such specified date other than at the option of the Holder thereof or (iii) upon compliance with the provisions of the following paragraph, securities described in clause (i), (iv), (vi), (vii) or (viii) of the definition of Investment Securities which are subject to redemption prior to maturity at the option of the issuer thereof on a specified date or dates.

Investment Securities described in clause (iii) of the foregoing paragraph may be included in the Investment Securities deposited with the Trustee for purposes of defeasance only if the determination as to whether the monies and Investment Securities to be deposited with the Trustee would be sufficient to pay when due, either at the maturity date thereof or, in the case of any Bonds to be redeemed prior to the maturity date thereof, on the redemption date or dates specified in any notice of redemption to be mailed by the Trustee or in the instructions to mail notice of redemption provided to the Trustee in accordance with the Resolution, the principal and Redemption Price, if applicable, and interest on the Bonds is made both on

FMPA-POD3-00086

HEARING EXHIBIT 00000496

the assumption that the Investment Securities described in clause (iii) of the foregoing paragraph were not redeemed at the option of the issuer prior to the maturity date thereof and on the assumptions that such Investment Securities would be redeemed by the issuer thereof at its option on each date on which such option could be exercised, that as of such date or dates interest ceased to accrue on such Investment Securities and that the proceeds of such redemption would not be reinvested by the Trustee.

In the event that Investment Securities described in such clause (iii) are deposited with the Trustee, then any notice of redemption to be mailed by the Trustee and any set of instructions relating to a notice of redemption given to the Trustee may provide, at the option of FMPA, that any redemption date or dates in respect of all or any portion of the Bonds to be redeemed on such date or dates may at the option of FMPA be changed to any other permissible redemption date or dates and that redemption dates may be established for any Bonds deemed to have been paid in accordance with the defeasance provisions of the Resolution upon their maturity date or dates at any time prior to the actual mailing of any applicable notice of redemption in the event that all or any portion of such Investment Securities have been called for redemption or have been redeemed by the issuer thereof prior to the maturity date thereof.

Events of Default and Remedies

Events of Default specified in the Resolution include (i) failure to pay principal or redemption price of any Bond or Parity Reimbursement Obligation when due; (ii) failure to pay any interest installment on any Bond or Parity Reimbursement Obligation or the unsatisfied balance of any Sinking Fund Installment thereon when due; (iii) certain events of bankruptcy or insolvency of FMPA, and (iv) default by FMPA in the performance or observance of any other of the covenants, agreements or conditions on its part contained in the Resolution or in the Bonds, and such default shall continue for a period of 90 days after written notice thereof specifying such default and requiring that it shall have been remedied and stating that such notice is a "Notice of Default" under the Resolution has been given to FMPA by the Trustee or to FMPA and to the Trustee by the Holders of not less than 10% principal amount of the Bonds Outstanding. Upon the happening of any such Event of Default the Trustee or the Holders of not less than twenty-five percent (25%) in principal amount of the Bonds then outstanding may declare the principal of and any accrued interest on all Bonds then outstanding due and payable immediately (subject to a rescission of such declaration upon the curing of such default before the Bonds have matured).

Upon the occurrence of any Event of Default which has not been remedied, FMPA will, upon demand of the Trustee (a) order all Project Participants to make payments due under the All-Requirements Power Supply Project Contracts directly to the Trustee for deposit in the Revenue Fund, (b) grant to the Trustee all rights and remedies of FMPA in the All-Requirements Power Supply Project Contracts, and (c) pay over or cause to be paid over to the Trustee forthwith, all monies, securities and funds held by FMPA in any Fund under the Resolution and all Revenues which are not paid directly to the Trustee. The Trustee will apply all monies, securities, funds and Revenues received during the continuance of an Event of Default in the following order: (i) to payment of the reasonable and proper fees, charges, expenses and liabilities of the Trustee and Paying Agents, (ii) to the payment of Operation and Maintenance Expenses and for reasonable renewals, repairs and replacements of the System necessary in the Trustee's judgment to prevent loss of Revenues, and (iii) to the payment of interest and principal or redemption price of Bonds or Parity Debt without preference or priority of interest over principal or principal over interest or of any installment of interest over any other installment of interest or of any Bond or Parity Debt over any other Bond or Parity Debt, unless the principal of all Bonds has not become or has not been declared due and payable, in which case first to the payment of interest and second to the payment of principal or redemption price on those Bonds or Parity Debt which have become due and payable in order of their due dates and, if the amount available is not sufficient to pay in full all the amounts due on any date, then to the payment thereof ratably, according to the amounts of interest, principal or redemption price due on such date. In addition, the Trustee will have the right to apply in an appropriate proceeding for appointment of a receiver of the System.

If an Event of Default has occurred and has not been remedied the Trustee may, and on written request of the holders of not less than twenty-five percent (25%) in principal amount of Bonds outstanding must, proceed to protect and enforce its rights and the rights of the holders of the Bonds under the Resolution forthwith by a suit or suits in equity or at law, whether for the specific performance of any covenant in the Resolution or in aid of the execution of any power granted in the Resolution or for an accounting against FMPA or in the enforcement of any other legal or equitable right, as the Trustee deems most effectual to enforce any of its rights or to perform any of its duties under the Resolution. The Trustee may, and upon the request of the holders of not less than twenty-five percent (25%) in principal amount of the Bonds then outstanding and upon being furnished with reasonable security and indemnity must, institute and maintain such suits and proceedings to prevent any impairment of security under the Resolution or to preserve or protect the interests of the Trustee and of the holders of the Bonds.

No holder of the Bonds will have any right to institute any suit, action or proceeding for the enforcement of any provision of the Resolution or the execution of any trust under the Resolution or for any remedy under the Resolution, unless (a) such holder of the Bonds previously has given the Trustee written notice of an Event of Default, (b) the holders of at least

FMPA-POD3-00087

HEARING EXHIBIT - 00000497

twenty-five percent (25%) in principal amount of the Bonds then outstanding have filed a written request with the Trustee and have afforded the Trustee a reasonable opportunity to exercise its powers or institute such suit, action or proceeding, (c) there have been offered to the Trustee adequate security and indemnity against its costs, expenses and liabilities to be incurred and (d) the Trustee has refused to comply with such request within 60 days after receipt of such notice, request and offer of indemnity. Nothing in the Resolution or the Bonds affects or impairs FMPA's obligation to pay the Bonds and interest thereon when due or the right of any holder of the Bonds to enforce such payment.

The holders of not less than a majority in principal amount of Bonds then outstanding may direct the time, method and place of conducting any proceeding for any remedy available to the Trustee or of exercising any trust or power conferred upon the Trustee, subject to the Trustee's right to decline to follow such direction upon advice of counsel as to the unlawfulness thereof or upon its good faith determination that such action would involve the Trustee in personal liability and the holders shall not indemnify the Trustee or would be unjustly prejudicial to holders of the Bonds not parties to such direction.

If the Bonds have not yet been accelerated and with the consent of the Insurer, the holders of not less than a majority in principal amount of the Bonds at the time outstanding may, on behalf of the holders of all the Bonds, waive any past default under the Resolution and its consequences, except a default in the payment of interest on or principal of, or premium, if any, on the Bonds.

Notice of Default

Notice of the occurrence of any Event of Default will be promptly mailed to each registered owner of Bonds then outstanding at his address appearing in the registry books of FMPA.

***Additional Provisions Relating to the Series 2005B Bonds* - Tax Covenants Relating to the Series 2005B Bonds**

FMPA covenants that, in order to maintain the exclusion from gross income for Federal income tax purposes of the interest on the Series 2005B Bonds, FMPA will satisfy, or take such actions as are necessary to cause to be satisfied, each provision of the Code necessary to maintain such exclusion. In furtherance of this covenant, FMPA agrees to comply with such written instructions as may be provided by Bond Counsel. In furtherance of the covenant contained in the preceding sentence, FMPA agrees to continually comply with the provisions of the "Tax Certificate as to Arbitrage and the Provisions of Sections 141-150 of the Internal Revenue Code of 1986" to be executed by FMPA in connection with the execution and delivery of the Series 2005B Bonds, as amended from time to time.

The Supplemental Resolution also contains provisions and restrictions with respect to defeasance which are related to the Code.

SUMMARY OF CERTAIN PROVISIONS OF THE ALL-REQUIREMENTS POWER SUPPLY PROJECT CONTRACTS

Term

Unless otherwise described in this Official Statement, the All-Requirements Power Supply Contracts shall remain in effect until October 1, 2037, and are thereafter subject to an automatic extension of one additional year past October 1, 2037. Each year the Power Supply Contract is automatically extended for one additional year so that it will always have a term of at least 30 years unless a Project Participant affirmatively elects, upon one year's prior notice, not to extend the Power Supply Contract. See also "Withdrawal by Participant" below.

Sale and Purchase

FMPA agrees to sell and deliver to the Project Participant, and the Project Participant agrees to purchase and receive from FMPA, all electric capacity and energy (including any associated transmission and dispatching services) which the Project Participant shall require for the operation of its municipal electric system over and above the Project Participant's Excluded Power Supply Resources, if any, specified in the All-Requirements Power Supply Project Contract and over and above Backup and Support Services (the "All-Requirements Services").

However, that on any January 1, upon at least five years prior written notice to FMPA, the Project Participant may limit the maximum amount of electric capacity and energy required to be sold and delivered by FMPA and purchased and received by the Project Participant as All-Requirements Services for the remainder of the term of the contract so as not to exceed the Contract Rate of Delivery determined as follows: the "Contract Rate of Delivery" shall be the peak demand of the Project Participant for electric capacity and energy as All-Requirements Services under the All-Requirements Power Supply

FMPA-POD3-00088

HEARING EXHIBIT 00000498

Project Contract during the 12 months preceding the date one month prior to the date such limitation shall commence, as determined by FMPA, adjusted up or down by not more than 15% so as to provide optimal utilization of the FMPA power supply resources, such adjustment to be made by FMPA in its sole discretion. Such Contract Rate of Delivery shall be reduced by FMPA by the total of the Project Participant's then current Capacity Credit Resources, and Partial Requirements Purchase Contract and any power supply resources the Project Participant is obligated to purchase from other FMPA power supply projects, if any, as defined and determined pursuant to the Project Participant's Capacity and Energy Sales Contract, if applicable. However, such reduction of the Contract Rate of Delivery shall not result in a negative amount of the Contract Rate of Delivery. Additionally, the Project Participant may not make such a reduction in the Contract Rate of Delivery more than once during the term of the Contract.

Payments by Each Participant

Each Project Participant is required to pay for all electric capacity and energy furnished pursuant to its All-Requirements Power Supply Project Contract at its point or points of delivery according to rates to be established by FMPA. The rates of FMPA are to be reviewed at least once a year and, if necessary, revised so as to provide revenues sufficient to meet the estimated "Revenue Requirements" of FMPA. The term Revenue Requirements is defined to include generally all costs and expenses paid or incurred or to be paid or incurred by FMPA resulting from the ownership, operation, maintenance, termination, retirement from service and decommissioning of, and repairs, renewals, replacements, additions, improvements, betterments and modifications to, the System or otherwise relating to the acquisition and sale of electric capacity and energy and dispatching and transmission services, providing Back-up and Support Services and the performance by FMPA of its obligations under the All-Requirements Power Supply Project Contracts. The term Revenue Requirements includes, without limitation, all debt service on Bonds issued by FMPA to finance its system and, all amounts required, under the Resolution, to be deposited in funds, including the Operation and Maintenance Fund established thereunder. FMPA is also required to bill each Project Participant monthly on a prompt and timely basis in accordance with a schedule to be determined by FMPA.

If a Project Participant fails to take power made available by FMPA which it is required to take under its All-Requirements Power Supply Project Contract, it will be obligated to pay the Agency for such availability an amount equal to the product of the demand charge in FMPA's rate schedule and the billing demand computed on the basis of the kilowatts that would otherwise have been taken from FMPA.

Payments by each Participant under its All-Requirements Power Supply Project Contract shall be treated as an operating expense from the revenues of its electric utility system (or, if the electric utility system is part of an integrated utility system, from the revenues of such larger system), and from other funds of such system legally available therefor. The obligation of each Project Participant to make such payments is not a general obligation and each Project Participant is not required to make such payments from any funds other than those of its electric utility system or integrated utility system of the Project Participant of which the electric utility system is part, and from other funds of such system legally available therefor.

The obligations of each Project Participant to make payments under the rate schedule shall not be subject to any reduction, whether by offset, counterclaim, recoupment or otherwise, and shall not be otherwise conditioned upon the performance by FMPA under the All-Requirements Power Supply Project Contract or any other agreement.

Rate Covenant

Each Project Participant agrees to establish, levy and collect rents, rates and other charges for all products and services provided by its electric or integrated utility system which rents, rates, and other charges shall be at least sufficient (i) to meet the operation and maintenance expenses of such electric or integrated utility system, (ii) to comply with all covenants pertaining thereto contained in, and all other provisions of, any resolution, trust indenture, or other security agreement relating to any bonds or other evidences of indebtedness issued or to be issued by the Project Participant, (iii) to generate funds sufficient to fulfill the terms of all other contracts and agreements made by the Project Participant, including, without limitation, its All-Requirements Power Supply Project Contract, and (iv) to pay all other amounts payable from or constituting a lien or charge on the revenues of its electric or integrated utility system.

Restrictions on Disposition of Electrical System, Sales for Resale

Each Project Participant has agreed that it will not sell, lease, abandon or otherwise dispose of all or substantially all of its electric or integrated utility system except on 90 days' prior written notice to FMPA and, in any event, shall not so sell, lease, abandon or otherwise dispose of the same unless the following conditions are met: (i) the Project Participant shall assign the All-Requirements Power Supply Project Contract and its rights and interest thereunder to the purchaser or lessee of the electric system and such purchaser or lessee shall assume all obligations of the Project Participant under the All-Requirements

FMPA-POD3-00089

HEARING EXHIBIT - 00000499

Power Supply Project Contract; (ii) FMPA shall be permitted by then applicable law to sell electric capacity and energy to said purchaser or lessee, if any; and (iii) FMPA shall by appropriate action determine, in its sole discretion, that such sale, lease, abandonment or other disposition will not adversely affect FMPA's ability to meet its obligations under the All-Requirements Power Supply Project Contract or any contract, agreement or arrangement to which FMPA is a party as either principal or agent pursuant to which FMPA satisfies all or any part of its obligations to provide electric capacity and energy and dispatching and transmission services under the All-Requirements Power Supply Project Contract or the All-Requirements Power Supply Project Contracts with the other Project Participants, and will not adversely affect the value of the All-Requirements Power Supply Project Contract as security for the payment of Bonds and interest thereon or adversely affect the eligibility of interest on Bonds then outstanding or which could be issued in the future for federal or State of Florida tax-exempt status.

A Project Participant may sell at wholesale any of the electric capacity and energy delivered to it pursuant to the All-Requirements Power Supply Project Contract to any customer of the Project Participant or any other entity for resale by that customer or entity, provided that it has first given FMPA five years' written notice of its intent to sell such electric capacity and energy and at the time of such notice provided FMPA with projected data regarding any such sales anticipated for the ensuing five year period. FMPA, after receipt of such notice, shall have 180 days in which to impose limits on the amount of electric capacity and energy to be sold or to veto such sale if the sale will jeopardize FMPA's availability of resources to serve its Project Participants, increase the cost of electric capacity and energy to FMPA, or violate the covenant of the Project Participant that it shall not use or permit to be used any of the electric capacity and energy acquired under the All-Requirements Power Supply Project Contract in any manner or for any purpose or take any other action or omit to take any action which would result in the loss of the federal or State of Florida tax-exempt status of the interest on any Bond or Bonds issued by FMPA or which could be issued by FMPA in the future.

Authorization and Approval of Additional Projects for the System

FMPA is authorized by the Project Participants to undertake projects to be included in the System as part of the All-Requirements Power Supply Project from time to time which are necessary or desirable to enable FMPA to fulfill satisfactorily its obligations to use its best efforts to supply electric capacity and energy to the Project Participants pursuant to the All-Requirements Power Supply Project Contracts and which projects, to the extent required by the next paragraph, have been approved by the Board and the Project Participants pursuant to the terms of the next paragraph and to issue Bonds for the purpose of paying all or any part of the costs of any of the projects or for any other purposes authorized by the laws of the State of Florida relating to the System.

The participation of FMPA in any project for the construction, acquisition, purchase, lease or other use of any generation, dispatching, load management or transmission resources, output or services that is to be included in the System requiring the issuance of Bonds by FMPA or assumption or guaranty by FMPA of other obligations or requiring the execution by FMPA of any power supply contract or agreement (other than interchange agreements with other utilities) with a basic term of more than seven (7) years must be approved by (a) a majority affirmative vote of all of the Project Participants, with each Project Participant entitled to cast one vote, and if so approved, (b) the Board and/or the Executive Committee of FMPA, to the extent and in a manner provided by the laws of the State of Florida, the Interlocal Agreement, the By-Laws of FMPA and/or the Resolution.

Withdrawal by Participant

A Participant may, but only upon satisfaction of certain conditions, terminate its Power Supply Contract and withdraw from the All-Requirements Project by notifying FMPA and all other Participants in writing of its intention to do so at least three years prior to the intended Withdrawal Date (which date must be a September 30). Any such notice shall be irrevocable.

The Project Participant shall, on the anticipated Withdrawal Date, pay to FMPA an amount in cash equal to:

1. the amount necessary to call (including payment of any required call premiums and interest to the call date or dates), on the first permissible call date or dates, a percentage of FMPA's then outstanding Bonds (other than Bonds issued to finance additions to the System which FMPA committed to after the receipt of the Project Participant's withdrawal notice) equal to the greater of the Project Participant's share of the All-Requirements Power Supply Project's total electric load on the date of receipt of the withdrawal notice or such share on the Withdrawal Date. Such amount shall be calculated on the assumption that the Bonds to be called will be the applicable percentage of each Series of such Bonds and of each maturity within each such Series. Unless all or any portion of such cash is needed at any time to cure any deficiency in any fund or account under the Resolution, FMPA will deposit such amount in a separate account in the General Reserve Fund and will retain such amount in such account pending its application to redeem Bonds, to purchase Bonds in the open market, or to pay

FMPA-POD3-00090

HEARING EXHIBIT 00000500

other capital costs of the All-Requirements Power Supply Project; pending the decision as to such application, such cash may be invested only in securities which could be deposited in an escrow fund to defease Bonds under the Resolution; and

2. an amount equal to the present value on the Withdrawal Date, calculated at the rate of 6% per annum, of all of the additional costs reasonably incurred, paid or reasonably anticipated to be incurred or paid, or reasonably projected to be incurred by FMPA (as determined by FMPA in its sole discretion) as a result of the withdrawal of the Project Participant, over the term specified in such Project Participant's All-Requirements Power Supply Project Contract (as determined on the anticipated Withdrawal Date). Such costs shall be determined on the assumption that, during the remaining term of such Project Participant's All-Requirements Power Supply Project Contract, FMPA was unable to make use of or sell any generating, transmission or other resources (or portions thereof) which FMPA had anticipated would be used to supply, or had acquired with the intention of supplying, all or any portion of the withdrawing Project Participant's electric load. Such amount shall, unless all or any portion thereof is required at any time to be used to cure any deficiency in any fund or account under the Resolution, be deposited into and retained in a separate account in the General Reserve Fund to be applied to pay any such costs actually incurred and/or to make any payments required to be made to such withdrawing Project Participant described below.

If and to the extent that any amounts received by FMPA pursuant to either clause 1 or clause 2 described above are applied to cure any deficiency in any fund or account under the Resolution, FMPA shall be required to restore to the separate account under clause 1 or clause 2 the amount so applied from the Revenues (as defined in the Resolution) of the All-Requirements Power Supply Project, and FMPA shall treat such obligation to restore as an expense of the All-Requirements Power Supply Project in determining Revenue Requirements. In addition, at the end of each fiscal year of the All-Requirements Power Supply Project, FMPA may, in its sole discretion, remove from either the separate account provided for payments received under clause 1 described above or the account provided for payments received under clause 2 described above, or both, such amounts determined by FMPA to be in excess of the amounts needed to make the payments anticipated to be made from such accounts and deposit such excess amounts in the General Reserve Fund itself.

In addition to the cash payments described above, any such withdrawal is subject to the receipt of the following approval, confirmation and opinion. If FMPA has Bonds outstanding which are secured by some form of credit support, any required approvals of the provider thereof shall have been obtained within six months of receipt of notice of withdrawal. If FMPA has any Bonds outstanding which are not so secured and which are rated by a national rating agency, the rating in effect prior to the delivery to FMPA of notice of such withdrawal must be confirmed by the rating agency within six months of such notice of withdrawal. FMPA must receive an opinion of Bond Counsel which determines that such withdrawal does not adversely affect the federal and/or State of Florida tax-exempt status on any Bonds then outstanding or which FMPA may issue in the future. If such withdrawal would require FMPA to obtain a "cap' allocation to issue any future Bonds, such requirement shall be treated as adversely affecting the federal and/or State of Florida tax-exempt status of Bonds or future bonds.

Within 180 days after the first anniversary of such withdrawal and annually thereafter for the specified term of the withdrawing Project Participant's All-Requirements Power Supply Project Contract (as such term is determined on the Withdrawal Date), FMPA will pay to the withdrawing Project Participant an amount equal to the additional benefits actually received by FMPA during the preceding year as a result of such withdrawal as calculated by FMPA in its sole discretion. The net amount of payments to the withdrawing Project Participant may not exceed 90% of the payment to FMPA by the Project Participant as described in clause 2 above. To the extent that the amounts remaining on deposit in the separate account described in clause 2 above are, or are anticipated to be, insufficient to make any payment described in this paragraph, the amount required to make such payment shall be treated as an expense of the All-Requirements Power Supply Project to be recovered as a Revenue Requirement.

If all of the foregoing conditions have not been satisfied on the anticipated Withdrawal Date, the Project Participant shall continue as a Project Participant in the All-Requirements Power Supply Project. In such event, the Project Participant shall pay all costs incurred by FMPA as a result of the Project Participant's anticipated withdrawal and subsequent continuance in the All-Requirements Power Supply Project, and FMPA shall have no obligation to make any payments to the Project Participant described in the preceding paragraph.

HEARING EXHIBIT - 00000501

[This Page Intentionally Left Blank]

HEARING EXHIBIT 00000502

APPENDIX D-1

Upon delivery of the Offered Securities in definitive form, Nixon Peabody LLP, New York, New York, Bond Counsel to the Agency, proposes to render its final approving opinion in substantially the following form:

437 Madison Avenue
New York, New York 10022
(212) 940-3000
Fax: (212) 940-3111

[Closing Date]

Board of Directors
Florida Municipal Power Agency
8553 Commodity Circle
Orlando, Florida 32819

Ladies and Gentlemen:

We have examined a record of proceedings relating to the issuance of $[_____] aggregate principal amount of All-Requirements Power Supply Project Revenue Bonds, Series 2006B-1 (Auction Rate Securities) (the "Series 2006B-1 Bonds"), $[_____] aggregate principal amount of All-Requirements Power Supply Project Revenue Bonds, Series 2006B-2 (Auction Rate Securities) (the "Series 2006B-2 Bonds"), $[_____] aggregate principal amount of All-Requirements Power Supply Project Revenue Bonds, Series 2006B-3 (Auction Rate Securities) (the "Series 2006B-3 Bonds") and $[_____] aggregate principal amount of All-Requirements Power Supply Project Revenue Bonds, Series 2006B-4 (Auction Rate Securities) (the "Series 2006B-4 Bonds", and collectively with the Series 2006 B-1 Bonds, the Series 2006 B-2 Bonds and the Series 2006 B-3 Bonds, the "Series 2006B Bonds") of Florida Municipal Power Agency ("FMPA"), a legal entity of the State of Florida, organized and existing under Section 163.01 and Chapter 361, Part II, of the Florida Statutes, as amended (collectively, the "Act").

The Series 2006B Bonds are issued under and pursuant to the Constitution and Statutes of the State of Florida, and particularly Chapter 166, Part II, Florida Statutes, as amended, and under and pursuant to a resolution of FMPA adopted on March 22, 1985 entitled "All-Requirements Power Supply Project Revenue Bond Resolution", as amended and restated in its entirety on May 23, 2003, as supplemented and amended to the date hereof, including as supplemented by the Multiple Series Supplemental All-Requirements Power Supply Project Revenue Bond Resolution, adopted on November 2, 2005, as amended by Amendment No. 1 to Multiple Series Supplemental All-Requirements Power Supply Project Revenue Bond Resolution, adopted on November 2, 2005, and as further amended by Amendment No. 2 to Multiple Series Supplemental All-Requirements Power Supply Project Revenue Bond Resolution, adopted on February 23, 2006, authorizing the Series 2006B Bonds (the "Supplemental Resolution") (such All-Requirements Power Supply Project Revenue Bond Resolution as so supplemented and amended being herein called the "Resolution").

The Series 2006B-1 Bonds are numbered from one (1) consecutively upward and have the numbers and letters 06B-1R prefixed to their numbers. The Series 2006B-2 Bonds are numbered from one (1) consecutively upward and have the numbers and letters 06B-2R prefixed to their numbers. The Series 2006B-3 Bonds are numbered from one (1) consecutively upward and have the numbers and letters 06B-3R prefixed to their numbers. The Series 2006B-4 Bonds are numbered from one (1) consecutively upward and have the numbers and letters 06B-4R prefixed to their numbers. The Series 2006B-1 Bonds shall mature on October 1, 2027. The Series 2006B-2 Bonds shall mature on October 1, 2027. The Series 2006B-3 Bonds shall mature on October 1, 2027. The Series 2006B-4 Bonds shall mature on October 1, 2035.

Unless the rate of interest on any Series of the Series 2006B Bonds is converted to a Fixed Rate, the Series 2006B Bonds of each Series shall bear interest from their date of initial issuance and delivery at a rate or rates determined as provided in the Resolution, which shall initially be for all Series 2006B Bonds at the Dutch Auction

FMPA-POD3-00093

HEARING EXHIBIT - 00000503

Rate, and are subject to redemption prior to maturity at the times, in the manner and upon the terms set forth in the Resolution. Interest on Series 2006B Bonds shall accrue from the date of issuance and shall be payable in arrears.

The Series 2006B Bonds are issuable in the form of fully registered bonds (i) in the denomination of $25,000 or any integral multiple of $5,000 in excess thereof for any Series of the Series 2006B Bonds bearing interest at a Dutch Auction Rate, (ii) in the denomination of $100,000 or any integral multiple of $5,000 in excess thereof for any Series of the Series 2006B Bonds bearing interest at a Daily Rate, a Weekly Rate, a Flexible Rate or the Bank Rate, or (iii) in the denomination of $5,000 or any integral multiple thereof for any Series of the Series 2006B Bonds bearing interest at a Fixed Rate. The Series 2006B Bonds are exchangeable as provided in the Resolution.

FMPA reserves the right to issue Additional Bonds and Refunding Bonds on the terms and conditions and for the purposes stated in the Resolution. Under the provisions of the Resolution, such Additional Bonds will rank equally as to security and payment with the Series 2006B Bonds and with FMPA's currently Outstanding All-Requirements Power Supply Project Revenue Bonds. Concurrently with the issuance of the Series 2006B Bonds, FMPA shall be issuing $125,020,000 aggregate principal amount of All-Requirements Power Supply Project Revenue Bonds, Series 2006A and $45,000,000 aggregate principal amount of All-Requirements Power Supply Project Revenue Bonds, Taxable Series 2006C (Auction Rate Securities).

All terms defined in the Resolution and used herein shall have the meanings assigned in the Resolution, except where the context hereof otherwise requires.

FMPA has entered into separate All-Requirements Power Supply Project Contracts with fifteen Florida entities (the "Participants") (as amended and supplemented from time to time, the "Power Supply Contracts"), pursuant to which FMPA will sell and deliver to each Participant, and each Participant agrees to purchase and receive from FMPA, all electric capacity and energy (including any associated transmission and dispatching services) which such Participant shall require for the operation of its municipal electric system over and above the Excluded Power Supply Resources (as defined in the Power Supply Contracts). The payments by each Participant under its Power Supply Contract shall be treated as an operating expense payable from the revenues of its electric utility system (or, if the electric utility system is part of an integrated utility system, from the revenues of such larger system) and from other funds of such system legally available therefor. The obligation of each Participant to make such payments is not a general obligation, and each Participant is not required to make such payments from any funds other than those of its electric utility system, or integrated utility system of the Participant of which the electric utility system is part, and from other funds of such system legally available therefor.

We have also examined one of said Series 2006B-1 Bonds, one of said Series 2006B-2 Bonds, one of said Series 2006B-3 Bonds and one of said Series 2006B-4 Bonds, as executed and, in our opinion, the form of each of said Series 2006B Bonds and its execution are regular and proper.

We are of the opinion that:

1. FMPA is a governmental legal entity duly created and validly existing under the provisions of the Act.

2. FMPA has the right and power under the Act to adopt the Resolution, and the Resolution has been duly and lawfully adopted by FMPA, is in full force and effect, is valid and binding upon FMPA and is enforceable in accordance with its terms, and no other authorization for the Resolution is required. The Resolution creates the valid pledge which it purports to create for the benefit of the holders of the Series 2006B Bonds of (i) the proceeds of the sale of Bonds, (ii) all right, title and interest of FMPA in, to and under the Power Supply Contracts, (iii) the Revenues (as defined in the Resolution), and (iv) all Funds, established by the Resolution (other than the Decommissioning Fund, if established) including the investment income, if any, thereon, subject only to the provisions of the Resolution permitting the application thereof for the purposes and on the terms and conditions set forth in the Resolution. The Resolution provides for the issuance or incurrence of certain obligations constituting Parity Debt relating to the Bonds which ranks equally as to security and payment with the Bonds to the extent and in the manner provided in the Resolution.

FMPA-POD3-00094
HEARING EXHIBIT - 00000504

3. FMPA is duly authorized and entitled to issue the Series 2006B Bonds and the Series 2006B Bonds have been duly and validly authorized and issued by FMPA in accordance with the Constitution and Statutes of the State of Florida, and particularly Chapter 166, Part II, Florida Statutes, as amended, and the Resolution, and constitute the valid and binding obligations of FMPA as provided in the Resolution, enforceable in accordance with their terms and the terms of the Resolution and entitled to the benefits of the Act and the Resolution. The Series 2006B Bonds are special obligations of FMPA payable solely out of the Revenues and other funds pledged thereto under the Resolution, and neither the State of Florida nor any political subdivision thereof, nor any city or other entity which is a member of FMPA, other than FMPA, is obligated to pay the principal of and premium, if any, and interest on the Series 2006B Bonds, and neither the faith and credit nor the taxing power of the State of Florida or any political subdivision thereof or any such city or other entity is pledged to the payment of the principal of and premium, if any, or interest on the Series 2006B Bonds. Under the Resolution, FMPA may issue additional Bonds and may incur additional obligations constituting Parity Debt on a parity with the Bonds.

4. FMPA has the right and power to enter into and carry out its obligations under each Power Supply Contract, and each Power Supply Contract has been duly authorized, executed and delivered by FMPA, and, assuming due authorization, execution and delivery by each respective Participant, constitutes a valid and binding agreement of FMPA in accordance with its terms.

5. Under the Constitution and general laws of the State of Florida, the Power Supply Contracts of the respective Participants constitute the valid and binding agreements of the respective Participants, enforceable in accordance with their respective terms. In rendering the foregoing opinion, we have made no investigation of, and do not express any opinion with respect to, the following as they may relate to the valid and binding nature of such Power Supply Contracts: (i) the legal existence or formation of any Participant or the incumbency of any official or officer thereof, (ii) the charter, bylaws or other governing instruments of any Participant, (iii) any local or special acts or any ordinance, resolution or other proceedings of any Participant, including without limitation any proceedings relating to the negotiation or authorization of any such Power Supply Contract or the execution, delivery or performance thereof, (iv) any bond resolution, indenture, contract, debt instrument, agreement or other instrument (other than such Power Supply Contracts) or any governmental order, regulation or rule of or applicable to any Participant, (v) any judicial order, judgment or decree in a proceeding to which any Participant is a party, or (vi) any approval, consent, filing, registration or authorization by or with any regulatory authority or other governmental or public agency, authority or person which may be or has been required for the authorization, execution, delivery or performance by any Participant of its Power Supply Contract. FMPA has received opinions, independent from this opinion, with respect to, among other things, the validity and enforceability of the Power Supply Contracts with the Participants rendered by legal counsel to the respective Participants.

6. The Internal Revenue Code of 1986, as amended (the "Code"), sets forth certain requirements that must be met subsequent to the issuance and delivery of the Series 2006B Bonds for interest thereon to be and remain excluded from gross income for Federal income tax purposes. Noncompliance with such requirements could cause the interest on the Series 2006B Bonds to be included in gross income for Federal income tax purposes retroactive to the date of issue of the Series 2006B Bonds. Pursuant to the Resolution, FMPA has covenanted to comply with applicable requirements of the Code in order to maintain the exclusion from gross income of the interest on the Series 2006B Bonds pursuant to Section 103(a) of the Code, and in furtherance thereof, to comply with the tax certificate executed by FMPA in connection with the issuance and delivery of the Series 2006B Bonds. In addition, FMPA has made certain factual representations and certification of expectations as to tax matters, contained in that tax certificate. We have not independently verified the accuracy of those certifications and representations.

Under existing law, and assuming compliance with the tax covenants described herein and the accuracy of the aforementioned representations and certification, interest on the Series 2006B Bonds is excluded from gross income for Federal income tax purposes under Section 103 of the Code. We are also of the opinion that such interest is not treated as a preference item in calculating the alternative minimum tax imposed under the Code with respect to individuals and corporations. Interest on the Series 2006B Bonds is, however, included in the adjusted current earnings of certain corporations for purposes of computing the alternative minimum tax imposed on such corporations.

7. The Series 2006B Bonds and the interest thereon are exempt from taxation under existing laws of the State of Florida, except as to estate taxes and taxes imposed by Chapter 220, Florida Statutes, on interest, income or profits on debt obligations owned by corporations, banks and savings associations.

Except as stated in the preceding paragraphs (6) and (7), we express no opinion as to any other Federal, state or local tax consequences of the ownership or disposition of the Series 2006B Bonds. Furthermore, we express no opinion as to any Federal, state or local tax law consequences with respect to the Series 2006B Bonds, or the interest thereon, if any action is taken with respect to the Series 2006B Bonds or the proceeds thereof upon the advice or approval of other bond counsel.

The opinions set forth above are subject to the effect of, and restrictions and limitations imposed by or resulting from, bankruptcy, insolvency, debt adjustment, moratorium, reorganization or other similar laws affecting creditors' rights and judicial discretion and the valid exercise of the sovereign police powers of the State of Florida and of the constitutional power of the United States of America.

By use of the word "enforceable" in this opinion, we are not rendering any opinion as to the availability of the remedy of specific performance or other equitable relief.

Very truly yours,

HEARING EXHIBIT - 00000506

APPENDIX D-2

Upon delivery of the Offered Securities in definitive form, Nixon Peabody LLP, New York, New York, Bond Counsel to the Agency, proposes to render its final approving opinion in substantially the following form:

437 Madison Avenue
New York, New York 10022
(212) 940-3000
Fax: (212) 940-3111

[Closing Date]

Board of Directors
Florida Municipal Power Agency
8553 Commodity Circle
Orlando, Florida 32819

Ladies and Gentlemen:

We have examined a record of proceedings relating to the issuance of $45,000,000 aggregate principal amount of All-Requirements Power Supply Project Revenue Bonds, Taxable Series 2006C (Auction Rate Securities) (the "Series 2006C Bonds") of Florida Municipal Power Agency ("FMPA"), a legal entity of the State of Florida, organized and existing under Section 163.01 and Chapter 361, Part II, of the Florida Statutes, as amended (collectively, the "Act").

The Series 2006C Bonds are issued under and pursuant to the Constitution and Statutes of the State of Florida, and particularly Chapter 166, Part II, Florida Statutes, as amended, and under and pursuant to a resolution of FMPA adopted on March 22, 1985 entitled "All-Requirements Power Supply Project Revenue Bond Resolution", as amended and restated in its entirety on May 23, 2003, as supplemented and amended to the date hereof, including as supplemented by the Multiple Series Supplemental All-Requirements Power Supply Project Revenue Bond Resolution, adopted on November 2, 2005, as amended by Amendment No. 1 to Multiple Series Supplemental All-Requirements Power Supply Project Revenue Bond Resolution, adopted on November 2, 2005, and as further amended by Amendment No. 2 to Multiple Series Supplemental All-Requirements Power Supply Project Revenue Bond Resolution, adopted on February 23, 2006, authorizing the Series 2006C Bonds (the "Supplemental Resolution") (such All-Requirements Power Supply Project Revenue Bond Resolution as so supplemented and amended being herein called the "Resolution").

The Series 2006C Bonds are numbered from one (1) consecutively upward and have the numbers and letters 06C-R prefixed to their numbers. The Series 2006C Bonds shall mature on October 1, 2025.

Unless the rate of interest on the Series 2006C Bonds is converted to a Fixed Rate, the Series 2006C Bonds shall bear interest from their date of initial issuance and delivery at a rate or rates determined as provided in the Resolution, which shall initially be for all Series 2006C Bonds at the Dutch Auction Rate, and are subject to redemption prior to maturity at the times, in the manner and upon the terms set forth in the Resolution. Interest on Series 2006C Bonds shall accrue from the date of issuance and shall be payable in arrears.

The Series 2006C Bonds are issuable in the form of fully registered bonds (i) in the denomination of $25,000 or any integral multiple of $5,000 in excess thereof for Series 2006C Bonds bearing interest at a Dutch Auction Rate, (ii) in the denomination of $100,000 or any integral multiple of $5,000 in excess thereof for Series 2006C Bonds bearing interest at a Daily Rate, a Weekly Rate, a Flexible Rate or the Bank Rate, or (iii) in the denomination of $5,000 or any integral multiple thereof for Series 2006C Bonds bearing interest at a Fixed Rate. The Series 2006C Bonds are exchangeable as provided in the Resolution.

FMPA-POD3-00097

HEARING EXHIBIT - 00000507

FMPA reserves the right to issue Additional Bonds and Refunding Bonds on the terms and conditions and for the purposes stated in the Resolution. Under the provisions of the Resolution, such Additional Bonds will rank equally as to security and payment with the Series 2006C Bonds and with FMPA's currently Outstanding All-Requirements Power Supply Project Revenue Bonds. Concurrently with the issuance of the Series 2006C Bonds, FMPA shall be issuing $125,020,000 aggregate principal amount of All-Requirements Power Supply Project Revenue Bonds, Series 2006A and $225,825,000 aggregate principal amount of All-Requirements Power Supply Project Revenue Bonds, Series 2006B (Auction Rate Securities).

All terms defined in the Resolution and used herein shall have the meanings assigned in the Resolution, except where the context hereof otherwise requires.

FMPA has entered into separate All-Requirements Power Supply Project Contracts with fifteen Florida entities (the "Participants") (as amended and supplemented from time to time, the "Power Supply Contracts"), pursuant to which FMPA will sell and deliver to each Participant, and each Participant agrees to purchase and receive from FMPA, all electric capacity and energy (including any associated transmission and dispatching services) which such Participant shall require for the operation of its municipal electric system over and above the Excluded Power Supply Resources (as defined in the Power Supply Contracts). The payments by each Participant under its Power Supply Contract shall be treated as an operating expense payable from the revenues of its electric utility system (or, if the electric utility system is part of an integrated utility system, from the revenues of such larger system) and from other funds of such system legally available therefor. The obligation of each Participant to make such payments is not a general obligation, and each Participant is not required to make such payments from any funds other than those of its electric utility system, or integrated utility system of the Participant of which the electric utility system is part, and from other funds of such system legally available therefor.

We have also examined one of said Series 2006C Bonds, as executed and, in our opinion, the form of said Series 2006C Bond and its execution are regular and proper.

We are of the opinion that:

1. FMPA is a governmental legal entity duly created and validly existing under the provisions of the Act.

2. FMPA has the right and power under the Act to adopt the Resolution, and the Resolution has been duly and lawfully adopted by FMPA, is in full force and effect, is valid and binding upon FMPA and is enforceable in accordance with its terms, and no other authorization for the Resolution is required. The Resolution creates the valid pledge which it purports to create for the benefit of the holders of the Series 2006C Bonds of (i) the proceeds of the sale of Bonds, (ii) all right, title and interest of FMPA in, to and under the Power Supply Contracts, (iii) the Revenues (as defined in the Resolution), and (iv) all Funds, established by the Resolution (other than the Decommissioning Fund, if established) including the investment income, if any, thereon, subject only to the provisions of the Resolution permitting the application thereof for the purposes and on the terms and conditions set forth in the Resolution. The Resolution provides for the issuance or incurrence of certain obligations constituting Parity Debt relating to the Bonds which ranks equally as to security and payment with the Bonds to the extent and in the manner provided in the Resolution.

3. FMPA is duly authorized and entitled to issue the Series 2006C Bonds and the Series 2006C Bonds have been duly and validly authorized and issued by FMPA in accordance with the Constitution and Statutes of the State of Florida, and particularly Chapter 166, Part II, Florida Statutes, as amended, and the Resolution, and constitute the valid and binding obligations of FMPA as provided in the Resolution, enforceable in accordance with their terms and the terms of the Resolution and entitled to the benefits of the Act and the Resolution. The Series 2006C Bonds are special obligations of FMPA payable solely out of the Revenues and other funds pledged thereto under the Resolution, and neither the State of Florida nor any political subdivision thereof, nor any city or other entity which is a member of FMPA, other than FMPA, is obligated to pay the principal of and premium, if any, and interest on the Series 2006C Bonds, and neither the faith and credit nor the taxing power of the State of Florida or any political subdivision thereof or any such city or other entity is pledged to the payment of the principal of and premium, if any, or interest on the Series 2006C Bonds. Under the Resolution, FMPA may issue additional Bonds and may incur additional obligations constituting Parity Debt on a parity with the Bonds.

FMPA-POD3-00098
HEARING EXHIBIT - 00000508

4. FMPA has the right and power to enter into and carry out its obligations under each Power Supply Contract, and each Power Supply Contract has been duly authorized, executed and delivered by FMPA, and, assuming due authorization, execution and delivery by each respective Participant, constitutes a valid and binding agreement of FMPA in accordance with its terms.

5. Under the Constitution and general laws of the State of Florida, the Power Supply Contracts of the respective Participants constitute the valid and binding agreements of the respective Participants, enforceable in accordance with their respective terms. In rendering the foregoing opinion, we have made no investigation of, and do not express any opinion with respect to, the following as they may relate to the valid and binding nature of such Power Supply Contracts: (i) the legal existence or formation of any Participant or the incumbency of any official or officer thereof, (ii) the charter, bylaws or other governing instruments of any Participant, (iii) any local or special acts or any ordinance, resolution or other proceedings of any Participant, including without limitation any proceedings relating to the negotiation or authorization of any such Power Supply Contract or the execution, delivery or performance thereof, (iv) any bond resolution, indenture, contract, debt instrument, agreement or other instrument (other than such Power Supply Contracts) or any governmental order, regulation or rule of or applicable to any Participant, (v) any judicial order, judgment or decree in a proceeding to which any Participant is a party, or (vi) any approval, consent, filing, registration or authorization by or with any regulatory authority or other governmental or public agency, authority or person which may be or has been required for the authorization, execution, delivery or performance by any Participant of its Power Supply Contract. FMPA has received opinions, independent from this opinion, with respect to, among other things, the validity and enforceability of the Power Supply Contracts with the Participants rendered by legal counsel to the respective Participants.

6. The Series 2006C Bonds and the interest thereon are exempt from taxation under existing laws of the State of Florida, except as to estate taxes and taxes imposed by Chapter 220, Florida Statutes, on interest, income or profits on debt obligations owned by corporations, banks and savings associations.

We note that interest on the Series 2006C Bonds is not excluded from gross income for federal income tax purposes and so will be fully subject to federal income taxation. Except as stated in the preceding paragraph (6), we express no opinion as to any other Federal, state or local tax consequences of the ownership or disposition of the Series 2006C Bonds. Furthermore, we express no opinion as to any Federal, state or local tax law consequences with respect to the Series 2006C Bonds, or the interest thereon, if any action is taken with respect to the Series 2006C Bonds or the proceeds thereof upon the advice or approval of other bond counsel.

The opinions set forth above are subject to the effect of, and restrictions and limitations imposed by or resulting from, bankruptcy, insolvency, debt adjustment, moratorium, reorganization or other similar laws affecting creditors' rights and judicial discretion and the valid exercise of the sovereign police powers of the State of Florida and of the constitutional power of the United States of America.

By use of the word "enforceable" in this opinion, we are not rendering any opinion as to the availability of the remedy of specific performance or other equitable relief.

Very truly yours,

FMPA-POD3-00099
HEARING EXHIBIT - 00000509

[This Page Intentionally Left Blank]

HEARING EXHIBIT - 00000510

APPENDIX E

BOOK-ENTRY-ONLY SYSTEM

The Depository Trust Company ("DTC"), the world's largest depository, is a limited-purpose trust company organized under the New York Banking Law, a "banking organization" within the meaning of the New York Banking Law, a member of the Federal Reserve System, a "clearing corporation" within the meaning of the New York Uniform Commercial Code, and a "clearing agency" registered pursuant to the provisions of Section 17A of the Securities Exchange Act of 1934. DTC holds and provides asset servicing for over 2.2 million issues of U.S. and non-U.S. equity, corporate and municipal debt issues, and money market instruments from over 100 countries that DTC's participants ("Direct Participants") deposit with DTC. DTC also facilitates the post-trade settlement among Direct Participants of sales and other securities transactions in deposited securities through electronic computerized book-entry transfers and pledges between Direct Participants' accounts. This eliminates the need for physical movement of securities certificates. Direct Participants include both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, clearing corporations, and certain other organizations. DTC is a wholly-owned subsidiary of The Depository Trust & Clearing Corporation ("DTCC"). DTCC, in turn, is owned by a number of Direct Participants of DTC and Members of the National Securities Clearing Corporation, Fixed Income Clearing Corporation, and Emerging Markets Clearing Corporation, (NSCC, FICC and EMCC, also subsidiaries of DTCC), as well as by the New York Stock Exchange, Inc., the American Stock Exchange LLC, and the National Association of Securities Dealers, Inc. Access to the DTC system is also available to others such as both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, and clearing corporations that clear through or maintain a custodial relationship with a Direct Participant, either directly or indirectly ("Indirect Participants"). DTC has Standard & Poor's highest rating: AAA. The DTC Rules applicable to its Participants are on file with the Securities and Exchange Commission. More information about DTC can be found at www.dtcc.com and www.dtc.org.

Purchases of Offered Securities under the DTC system must be made by or through Direct Participants, which will receive a credit for the Offered Securities on DTC's records. The ownership interest of each actual purchaser of Offered Securities ("Beneficial Owner") is in turn to be recorded on the Direct and Indirect Participants' records. Beneficial Owners will not receive written confirmation from DTC of their purchase. Beneficial Owners are, however, expected to receive written confirmations providing details of the transaction, as well as periodic statements of their holdings, from the Direct or Indirect Participant through which the Beneficial Owner entered into the transaction. Transfers of ownership interests in Offered Securities are to be accomplished by entries made on the books of Direct and Indirect Participants acting on behalf of Beneficial Owners. Beneficial Owners will not receive certificates representing their ownership interests in Offered Securities, except in the event that use of the book-entry system for a series of Offered Securities is discontinued.

To facilitate subsequent transfers, all the Offered Securities deposited by Direct Participants with DTC are registered in the name of DTC's partnership nominee, Cede & Co. or such other name as may be requested by an authorized representative of DTC. The deposit of a series of Offered Securities with DTC and their registration in the name of Cede & Co. or such other DTC nominee do not effect any change in beneficial ownership. DTC has no knowledge of the actual Beneficial Owners of Offered Securities; DTC's records reflect only the identity of the Direct Participants to whose accounts Offered Securities are credited, which may or may not be the Beneficial Owners. The Direct and Indirect Participants will remain responsible for keeping account of their holdings on behalf of their customers.

Conveyance of notices and other communications by DTC to Direct Participants, by Direct Participants to Indirect Participants, and by Direct Participants and Indirect Participants to Beneficial Owners will be governed by arrangements among them, subject to any statutory or regulatory requirements as may be in effect from time to time. BENEFICIAL OWNERS SHOULD MAKE APPROPRIATE ARRANGEMENTS WITH THEIR BROKER OR DEALER TO RECEIVE NOTICES (INCLUDING NOTICES OF REDEMPTION) AND OTHER INFORMATION REGARDING OFFERED SECURITIES THAT MAY BE SO CONVEYED TO DIRECT PARTICIPANTS AND INDIRECT PARTICIPANTS.

Neither DTC nor Cede & Co. (nor any other DTC nominee) will consent or vote with respect to Offered Securities unless authorized by a Direct Participant in accordance with DTC's Procedures. Under its usual procedures, DTC mails an Omnibus Proxy to the FMPA as soon as possible after the record date. The Omnibus

FMPA-POD3-00101
HEARING EXHIBIT - 00000511

Proxy assigns Cede & Co.'s consenting or voting rights to those Direct Participants to whose accounts Offered Securities are credited on the record date (identified in a listing attached to the Omnibus Proxy).

Except as described below, neither DTC nor Cede & Co. will take any action to enforce covenants with respect to any security registered in the name of Cede & Co. Under its current procedures, on the written instructions of a Direct Participant, DTC will cause Cede & Co. to sign a demand to exercise bondholder rights as record holder of the quantity of securities specified in the Direct Participant's instructions, and not as record holder of all the securities of that issue registered in the name of Cede & Co. Also, in accordance with DTC's current procedures, all factual representations to be made by Cede & Co. to FMPA, the Trustee or any other party must be made to DTC and Cede & Co. by the Direct Participant in its instructions to DTC.

For so long as Offered Securities are issued in book-entry form through the facilities of DTC, any Beneficial Owner desiring to cause FMPA or the Trustee to comply with any of its obligations with respect to Offered Securities must make arrangements with the Direct Participant or Indirect Participant through whom such Beneficial Owner's ownership interest in Offered Securities is recorded in order for the Direct Participant in whose DTC account such ownership interest is recorded to make the instructions to DTC described above.

NEITHER FMPA NOR THE TRUSTEE NOR THE UNDERWRITER (OTHER THAN IN ITS CAPACITY, IF ANY, AS A DIRECT PARTICIPANT OR AN INDIRECT PARTICIPANT) WILL HAVE ANY OBLIGATION TO THE DIRECT PARTICIPANTS OR THE INDIRECT PARTICIPANTS OR THE PERSONS FOR WHOM THEY ACT AS NOMINEES WITH RESPECT TO DTC'S PROCEDURES OR ANY PROCEDURES OR ARRANGEMENTS BETWEEN DIRECT PARTICIPANTS, INDIRECT PARTICIPANTS AND THE PERSONS FOR WHOM THEY ACT RELATING TO THE MAKING OF ANY DEMAND BY CEDE & CO. AS THE REGISTERED OWNER OF OFFERED SECURITIES, THE ADHERENCE TO SUCH PROCEDURES OR ARRANGEMENTS OR THE EFFECTIVENESS OF ANY ACTION TAKEN PURSUANT TO SUCH PROCEDURES OR ARRANGEMENTS.

Principal and interest payments on Offered Securities will be made to Cede & Co., or such other nominee as may be requested by an authorized representative of DTC. DTC's practice is to credit Direct Participants' accounts, upon DTC's receipt of funds and corresponding detail information from FMPA or the Trustee, on payable date in accordance with their respective holdings shown on DTC's records. Payments by Participants to Beneficial Owners will be governed by standing instructions and customary practices, as is the case with securities held for the accounts of customers in bearer form or registered in "street name", and will be the responsibility of such Participant and not of DTC, the Trustee or FMPA, subject to any statutory or regulatory requirements as may be in effect from time to time. Payment of principal and interest to Cede & Co. (or such other nominee as may be requested by an authorized representative of DTC) is the responsibility of FMPA or the Trustee, disbursement of such payments to Direct Participants will be the responsibility of DTC, and disbursement of such payments to the Beneficial Owners will be the responsibility of Direct and Indirect Participants.

THE ABOVE INFORMATION CONCERNING DTC AND DTC'S BOOK-ENTRY SYSTEM HAS BEEN OBTAINED FROM SOURCES THAT FMPA BELIEVES TO BE RELIABLE, BUT FMPA TAKES NO RESPONSIBILITY FOR THE ACCURACY THEREOF. NEITHER FMPA NOR THE TRUSTEE WILL HAVE ANY RESPONSIBILITY OR OBLIGATION TO PARTICIPANTS, BENEFICIAL OWNERS OR OTHER NOMINEES OF SUCH BENEFICIAL OWNERS FOR (1) SENDING TRANSACTION STATEMENTS; (2) MAINTAINING, SUPERVISING OR REVIEWING, OR THE ACCURACY OF, ANY RECORDS MAINTAINED BY DTC OR ANY PARTICIPANT OR OTHER NOMINEES OF SUCH BENEFICIAL OWNERS; (3) PAYMENT OR THE TIMELINESS OF PAYMENT BY DTC TO ANY PARTICIPANT, OR BY ANY PARTICIPANT OR OTHER NOMINEES OF BENEFICIAL OWNERS TO ANY BENEFICIAL OWNER, OF ANY AMOUNT DUE IN RESPECT OF THE PRINCIPAL OF OR REDEMPTION PREMIUM, IF ANY, INTEREST OR PURCHASE PRICE ON OFFERED SECURITIES; (4) DELIVERY OR TIMELY DELIVERY BY DTC TO ANY PARTICIPANT, OR BY ANY PARTICIPANT OR OTHER NOMINEES OF BENEFICIAL OWNERS TO ANY BENEFICIAL OWNERS, OF ANY NOTICE (INCLUDING NOTICE OF REDEMPTION) OR OTHER COMMUNICATION WHICH IS REQUIRED OR PERMITTED UNDER THE TERMS OF THE RESOLUTION TO BE GIVEN TO HOLDERS OR OWNERS OF OFFERED SECURITIES; (5) THE SELECTION OF THE BENEFICIAL OWNERS TO RECEIVE PAYMENT IN THE EVENT OF ANY PARTIAL

REDEMPTION OF OFFERED SECURITIES; OR (6) ANY ACTION TAKEN BY DTC OR ITS NOMINEE AS THE REGISTERED OWNER OF OFFERED SECURITIES.

So long as Cede & Co. is the registered owner of Offered Securities, as nominee for DTC, references in this Official Statement to the Bondholders, holders or registered owners of Offered Securities (other than under the caption "Tax Matters" herein) shall mean Cede & Co., as aforesaid, and shall not mean the Beneficial Owners of Offered Securities.

When reference is made to any action which is required or permitted to be taken by the Beneficial Owners, such reference shall only relate to those permitted to act (by statute, regulation or otherwise) on behalf of such Beneficial Owners for such purposes. When notices are given, they shall be sent by FMPA or the Trustee to DTC only.

As long as the book-entry system is used for Offered Securities, the Trustee and FMPA will give any notices required to be given to Owners of Offered Securities only to DTC. Any failure of DTC to advise any Direct Participant, or of any Direct Participant to notify any Indirect Participant, or of any Direct Participant or Indirect Participant to notify any Beneficial Owner, of any such notice and its content or effect will not affect the validity of the action premised on such notice. Conveyance of notices and other communications by DTC to Direct Participants, by Direct Participants to Indirect Participants and by Direct Participants and Indirect Participants to Beneficial Owners will be governed by arrangements among them, subject to any statutory or regulatory requirements as may be in effect from time to time. Beneficial owners may desire to make arrangements with a Direct Participant or Indirect Participant so that all notices of redemption or other communications to DTC which affect such Beneficial Owners will be forwarded in writing by such Direct Participant or Indirect Participant.

NEITHER FMPA NOR THE TRUSTEE WILL HAVE ANY RESPONSIBILITY OR OBLIGATION TO SUCH DIRECT PARTICIPANTS, OR THE PERSONS FOR WHOM THEY ACT AS NOMINEES, WITH RESPECT TO THE PAYMENTS TO OR THE PROVIDING OF NOTICE FOR THE DIRECT PARTICIPANTS, THE INDIRECT PARTICIPANTS, OR THE BENEFICIAL OWNERS OF OFFERED SECURITIES.

For every transfer and exchange of a beneficial ownership interest in Offered Securities, the Beneficial Owner may be charged a sum sufficient to cover any tax, fee or other governmental charge that may be imposed in relation thereto.

DTC may discontinue providing its services as depository with respect to Offered Securities at any time by giving reasonable notice to FMPA or the Trustee. Under such circumstances, in the event that a successor depository is not obtained, certificates for the Offered Securities are required to be printed and delivered.

FMPA may decide to discontinue use of the system of book-entry transfers through DTC (or a successor securities depository). In that event, certificates for the Offered Securities will be printed and delivered to DTC.

FMPA-POD3-00103

HEARING EXHIBIT - 00000513

[This Page Intentionally Left Blank]

HEARING EXHIBIT - 00000514

APPENDIX F

CONTINUING DISCLOSURE UNDER SEC RULE 15c2-12

Pursuant to Rule 15c2-12 under the Securities Exchange Act of 1934, the Agency has undertaken for the benefit of Holders of the Bonds to provide certain financial information and operating data relating to the Agency by no later than nine months after the end of each Agency fiscal year, commencing with the fiscal year ending September 30, 2006 (the "Annual Financial Information"), and to provide notices of the occurrence of certain enumerated events, if material. The Annual Financial Information is required to be filed by or on behalf of the Agency with each Nationally Recognized Municipal Securities Information Repository (the "NRMSIRs") and with the State of Florida information depository, if and to the extent it shall have been established and shall be in existence and operating as a state information depository within the meaning of Rule 15c2-12 (the "State Information Depository"). Notices of material events are required to be filed by or on behalf of the Agency with the NRMSIRs or the Municipal Securities Rulemaking Board (the "MSRB") and with the State Information Depository. Any filing will be made solely by transmitting such filing to the Texas Municipal Advisory Council as provided at http://www.disclosureusa.org in its capacity as "Central Post Office," unless the Commission has withdrawn the interpretive advice in its letter to the Texas Municipal Advisory Council dated September 7, 2004. The nature of the information to be provided in the Annual Financial Information and the notices of material events is set forth below.

The required Annual Financial Information shall consist of (1) the Annual Agency Financial Information consisting of (A) financial and operating data relating to the Agency's All-Requirements Power Supply Project consisting of: (i) a description of the Agency's All-Requirements Power Supply Project; (ii) information of the type included in the table captioned "Historical Capacity Requirements and Resources" under the heading "THE PROJECT" for the three most recently completed fiscal years; (iii) historical operating results for the All-Requirements Project for the three most recently completed fiscal years, including net sales to cities and net power costs; and (iv) information concerning the Agency's debt service requirements for the All-Requirements Project; (B) a presentation of the Agency's financial results in accordance with GAAP for the two most recent completed fiscal years for which that information is then currently available; (C) material litigation related to any of the foregoing; together with (D) such narrative explanation as may be necessary to avoid misunderstanding and to assist the reader in understanding the presentation of financial information and operating data concerning, and in judging the financial condition of, the Agency; and (2) the Annual Major Participant Financial Information consisting of (A) financial and operating data consisting of: (i) the information of the type contained herein in Appendix B — "THE MAJOR PARTICIPANTS", other than the information contained under the heading "General"; (ii) information concerning sales of electric services, customers, and non-coincident peak demand; and (iii) a presentation of the Major Participants' information concerning historical net energy requirements and peak demand; (B) material litigation related to any of the foregoing; together with (C) such narrative explanation as may be necessary to avoid misunderstanding and to assist the reader in understanding the presentation of financial information and operating data concerning, and in judging the financial condition of, the Major Participants. For the purpose of determining which Participants constitute "Major Participants," any Participant which as of September 30 in any year accounts for 10% or more of the Revenues for the Project for the preceding fiscal year will be deemed a Major Participant.

The type of historical financial information and operating data relating to the Agency described above is currently included herein under the headings "DEBT SERVICE REQUIREMENTS" and "THE PROJECT." The type of financial information and operating data relating to the Major Participants described above is currently included herein under the headings "THE PROJECT PARTICIPANTS", APPENDIX A — "MEMBER PARTICIPATION IN FMPA PROJECTS" and APPENDIX B — "THE MAJOR PARTICIPANTS." The requirements contained in the undertaking discussed above are intended to set forth a general description of the type of financial information and operating data to be provided; such descriptions are not intended to state more than general categories of financial information and operating data; and where information required to be disclosed can no longer be generated because the operations to which it related have been materially changed or discontinued, a statement to that effect shall be provided.

All or any portion of the Annual Financial Information, as well as the Audited Financial Statements, may be incorporated therein by cross reference to any other documents which have been filed with (i) the Repositories and the State Information Depository or (ii) the Securities and Exchange Commission; provided, however, that if the document is an official statement, it shall have been filed with the MSRB and need not have been filed elsewhere.

FMPA-POD3-00105
HEARING EXHIBIT - 00000515

Annual Financial Information for any fiscal year containing any modified operating data or financial information for each such fiscal year shall explain, in narrative form, the reasons for such modification and the effect of such modification on the Annual Financial Information being provided for such fiscal year. If a change in accounting principles is included in any such modification, such Annual Financial Information shall present a comparison between the financial statements or information prepared on the basis of the modified accounting principles and those prepared on the basis of the former accounting principles. Such comparison shall include a qualitative discussion of the differences in the accounting principles and the impact of the change in the accounting principles on the presentation of the financial information. To the extent feasible, such comparison shall also be quantitative. A notice of any such change in accounting principles shall be sent to each Repository or to the MSRB, and to the State Information Depository.

Pursuant to Rule 15c2-12 under the Securities Exchange Act of 1934, the Agency will undertake for the benefit of Holders of the Bonds to provide or cause to be provided either directly or through the Trustee, Audited Financial Statements of the Agency and the Major Participants by no later than nine months after the end of each fiscal year commencing with the fiscal year ending September 30, 2006, when and if such audited financial statements become available and, if such audited financial statements are not available on the date which is nine months after the end of a fiscal year, the unaudited financial statements of the Agency and Major Participants for such fiscal year. The Audited Agency Financial Statements and the Audited Major Participant Financial Statements will be filed by or on behalf of the Agency with each NRMSIR and the State Information Depository.

The Agency will undertake, for the benefit of Holders of the Bonds, to provide or cause to be provided either directly or through the Trustee: (a) to each NRMSIR or the MSRB and to the State Information Depository in a timely manner, notice of any of the following events with respect to the Bonds, if material: (1) principal and interest payment delinquencies; (2) non-payment related defaults; (3) unscheduled draws on debt service reserves reflecting financial difficulties; (4) unscheduled draws on credit enhancements reflecting financial difficulties; (5) substitution of credit or liquidity providers, or their failure to perform; (6) adverse tax opinions or events affecting the tax-exempt status of the Bonds; (7) modifications to the rights of security holders; (8) bond calls (which do not include regularly scheduled or mandatory sinking fund redemptions effectuated in accordance with the Resolution); (9) defeasances; (10) release, substitution, or sale of property securing repayment of the Bonds; and (11) rating changes; and (b) to each NRMSIR or to the MSRB and to the State Information Depository, in a timely manner, notice of failure to provide any Annual Financial Information required by such undertaking.

The Agency will request, obtain and provide, pursuant to the Power Supply Contracts or otherwise, Annual Major Participant Financial Information, Audited Major Participant Financial Statements, and information relating to any change in fiscal year and the basis on which audited financial statements are prepared, from time to time and in sufficient time to permit the Agency to comply with the provisions of the undertaking, and shall enforce such provisions of the undertaking; the failure of any Major Participant to furnish any such requested information or data shall not excuse the performance by the Agency of any of its obligations under the undertaking. Under the Power Sales Contracts, the Participants are required to furnish to the Agency, upon request, all information, financial statements and other documents as shall be reasonably necessary in connection with the financing of the All-Requirements Power Supply Project.

If the Agency fails to comply with any provision of its undertaking described herein, then the Trustee or any Holder of the Bonds (which will include beneficial owners during any period that DTC acts as securities depository for, and DTC or its nominee is the registered owner of, the Bonds) may enforce, for the equal benefit and protection of all Holders similarly situated, by mandamus or other suit or proceeding at law or in equity, the undertaking against the Agency and any of its officers, agents and employees, and may compel the Agency or any such officers, agents or employees to perform and carry out their duties thereunder; *provided* that the sole and exclusive remedy for breach or default under the undertaking is an action to compel specific performance, and no person, including any Holder of Bonds, may recover monetary damages thereunder under any circumstances, and *provided further* that any challenge to the adequacy of any information under the undertaking may be brought only by the Trustee or the Holders of 25 percent in aggregate principal amount of the Bonds at the time outstanding which are affected thereby. Failure to comply with any provisions of the undertaking shall not constitute a default under the Resolution nor give right to the Trustee or any Holder to exercise any of the remedies under the Resolution.

HEARING EXHIBIT - 0000051

The foregoing is intended to set forth a general description of the type of financial information and operating data that will be provided; the descriptions are not intended to state more than general categories of financial information and operating data; and where the Agency's undertaking calls for information that no longer can be generated or is no longer relevant because the operations to which it related have been materially changed or discontinued, a statement to that effect will be provided. The Agency does not anticipate that it often will be necessary to amend the undertaking. The undertaking, however, may be amended or modified under certain circumstances set forth therein and the undertaking will continue until the earlier of the date the Bonds have been paid in full or legally defeased pursuant to the Resolution or the date the undertaking is no longer required by law. Copies of the undertaking when executed by the parties will be on file at the office of the Agency.

FMPA-POD3-00107
HEARING EXHIBIT - 00000517

[This Page Intentionally Left Blank]

HEARING EXHIBIT - 00000518

APPENDIX G

Form of Bond Insurance Policy

HEARING EXHIBIT - 00000519

[This Page Intentionally Left Blank]

HEARING EXHIBIT - 00000520



CIFG Assurance North America, Inc.
825 Third Avenue, Sixth Floor
New York, NY 10022
For information, contact (212) 909-3939
Toll-free (866) 243-4212

FINANCIAL GUARANTY INSURANCE POLICY

ISSUER: _____ Policy No.: CIFG NA-##

CUSIP: _____ Effective Date: _____, 200_

OBLIGATIONS: _____

CIFG ASSURANCE NORTH AMERICA, INC. ("CIFG NA"), for consideration received, hereby UNCONDITIONALLY AND IRREVOCABLY GUARANTEES to each Policyholder, subject only to the terms and conditions of this Policy (which includes each endorsement hereto), the full and complete payment by or on behalf of the Issuer of Regular Payments of principal of and interest on the Obligations.

For the further protection of each Policyholder, CIFG NA irrevocably and unconditionally guarantees:

(1) payment of any amount required to be paid under this Policy by CIFG NA following CIFG NA's receipt of notice and instruments of assignment as described in Endorsement No. 1 hereto and

(2) payment of the amount of any distribution of principal of and interest on the Obligations made during the Term of this Policy to such Policyholder that is subsequently avoided in whole or in part as a preferential payment under applicable law, all as described in Endorsement No. 1 hereto.

CIFG NA shall be subrogated to the rights of each Policyholder to receive payments under the Obligations to the extent of any payment by CIFG NA hereunder. Upon disbursement in respect of an Obligation, CIFG NA shall become the owner of the Obligation, appurtenant coupon, if any, and all rights to payment of principal thereof or interest thereon.

The following terms shall have the meanings specified herein, subject to and including any modifications set forth in any endorsement hereto, for all purposes of this Policy: "Effective Date," "Issuer" and "Obligations" mean, respectively, the Effective Date, Issuer and Obligations referenced above. "Policyholder" means, if the Obligations are in book-entry form, the registered owner of any Obligation as indicated on the registration books maintained by or on behalf of the Issuer for such purpose or, if the Obligations are in bearer form, the holder of any Obligation; *provided, however, that* any trustee acting on behalf of and for the benefit of such registered owner or holder shall be deemed to be the Policyholder to the extent of such trustee's authority. "Regular Payments" means payments of interest and principal which are agreed to be made during the Term of this Policy in accordance with the original terms of the Obligations when issued and without regard to any amendment or modification of such Obligations thereafter; payments which become due on an accelerated basis as a result of (a) a default by the Issuer or any other person, (b) an election by the Issuer to pay principal or other amounts on an accelerated basis or (c) any other cause, shall not constitute "Regular Payments" unless CIFG NA shall elect, in its sole discretion, to pay such principal due upon such acceleration together with any accrued interest to the date of acceleration. "Term of this Policy" has the meaning set forth in Endorsement No. 1 hereto.

This Policy sets forth in full the undertaking of CIFG NA, and shall not be modified, altered or affected by any other agreement or instrument, including any modification or amendment thereto or to the Obligations (except a contemporaneous or subsequent agreement or instrument given by CIFG NA or to which CIFG NA has given its written consent) or by the merger, consolidation or dissolution of the Issuer. The premiums paid in respect of this Policy are nonrefundable for any reason whatsoever, including payment, or provision being made for payment, of the Obligations prior to maturity. This Policy may not be cancelled or revoked during the Term of this Policy, including for nonpayment of premium due to CIFG NA. Payments under this Policy may not be accelerated except at the sole option of CIFG NA.

In witness whereof, CIFG ASSURANCE NORTH AMERICA, INC. has caused this Policy to be executed on its behalf by its Authorized Officer.

CIFG ASSURANCE NORTH AMERICA, INC.

By _____
Authorized Officer

SPECIMEN

[This Page Intentionally Left Blank]

HEARING EXHIBIT - 00000522

APPENDIX H

DUTCH AUCTION PROCEDURES

The following is a summary of definitions of certain terms relating to the Dutch Auction Procedures. The definitions apply separately to each Series of the Offered Securities while it bears interest at the Dutch Auction Rate.

"Agency" shall mean FMPA.

"Agent Member" shall mean a member of, or participant in, DTC.

"All Hold Rate" shall mean on any date of determination the interest rate per annum equal to the least of (i) 10%, and (ii)(a) for the Series 2006C Bonds, 90% (as such percentage may be adjusted pursuant to the Supplemental Resolution) of the Commercial Paper/Treasury Rate on such date or (b) for the Series 2006B Bonds, 90% of the Dutch Auction Index on such date.

"Applicable Percentage" shall mean on any date of determination the percentage determined as set forth below (as such percentage may be adjusted pursuant to "Auction Period-General") based on the prevailing rating of the Offered Securities in effect at the close of business on the Business Day immediately preceding such date of determination:

Prevailing Rating	Applicable Percentage (Tax-Exempt)	Applicable Percentage (Taxable)
Aaa/AAA	225%	225%
Aa/AA	250	250
A/A	275	275
Baa/BBB	300	300
Below Baa/BBB	350	350

For purposes of this definition, the prevailing rating of the Offered Securities will be (a) Aaa/AAA if the Offered Securities have a rating of Aaa by Moody's and a rating of AAA by Fitch, (b) if not Aaa/AAA, then Aa/AA if the Offered Securities have a rating of Aa3 or better by Moody's and a rating of AA or better by Fitch, (c) if not Aaa/AAA or Aa/AA, then A/A if the Offered Securities have a rating of A3 or better by Moody's and a rating of A or better by Fitch, (d) if not Aaa/AAA, Aa/AA or A/A, then Baa/BBB, if the Offered Securities have a rating of Baa3 or better by Moody's and a rating of BBB or better by Fitch, and (e) if not Aaa/AAA, Aa/AA, A/A or Baa/BBB, then below Baa/BBB.

"Auction" shall mean each periodic implementation of the Dutch Auction Procedures.

"Auction Agent Agreement" shall mean the Auction Agent Agreement between the Agency and the Auction Agent as amended and supplemented from time to time.

"Auction Agent" shall mean the auction agent appointed in accordance with the Resolution.

"Auction Date" shall mean for each Series of the Series 2006B Bonds and Series 2006C Bonds the first auction date set forth on the inside front cover page of this Official Statement for such Series, and with respect to (i) the Series 2006B-1 Bonds and Series 2006B-2 Bonds for each Auction Period thereafter the last Monday of the immediately preceding Auction Period or, if such last Monday is not a Business Day, the next preceding Business Day; (ii) the Series 2006B-3 Bonds for each Auction Period thereafter the last Wednesday of the immediately preceding Auction Period or, if such last Wednesday is not a Business Day, the next preceding Business Day; (iii) the Series 2006B-4 Bonds for each Auction Period thereafter the last Friday of the immediately preceding Auction Period or, if such last Friday is not a Business Day, the next preceding Business Day; and (iv) the Series 2006C Bonds for each Auction Period thereafter the last Thursday of the immediately preceding Auction Period or, if such last Thursday is not a Business Day, the next preceding Business Day.

FMPA-POD3-00113
HEARING EXHIBIT - 00000523

"Auction Period" shall mean, during a Dutch Auction Rate Period, each period from and including the dated date of the Offered Securities to and including April 10, 2006 in the case of the Series 2006B-1 Bonds and Series 2006B-2 Bonds, April 12, 2006 in the case of the Series 2006B-3 Bonds, April 9, 2006 in the case of the Series 2006B-4 Bonds and April 13, 2006 in the case of the Series 2006C Bonds and, thereafter, for each Series of the Series 2006B Bonds and Series 2006C Bonds from and including the last Interest Payment Date for the immediately preceding Auction Period, to and including the earliest of (i) October 1, 2027, in the case of the Series 2006B-1 Bonds, Series 2006B-2 Bonds and Series 2006B-3 Bonds, October 1, 2035, in the case of the Series 2006B-4 Bonds and October 1, 2025, in the case of the Series 2006C Bonds, (ii) the day next preceding the last Interest Payment Date in respect of each Auction Period and (iii) the last day of such Dutch Auction Rate Period.

"Available Auction Bonds" shall have the meaning set forth below under "Determination of Sufficient Clearing Bids, Winning Bid Rate and Dutch Auction Rate".

"Bid" shall have the meaning set forth below under "Orders by Existing Holders and Potential Holders".

"Bidder" shall have the meaning set forth below under "Orders by Existing Holders and Potential Holders".

"Broker-Dealer" shall mean any entity permitted by law to perform the functions required of a Broker-Dealer set forth in the Dutch Auction Procedures (i) that is an Agent Member (or an affiliate of an Agent Member), (ii) that has been selected by the Auction Agent with the consent of the Agency, and (iii) that has entered into a Broker-Dealer Agreement with the Auction Agent that remains effective.

"Broker-Dealer Agreement" shall mean each agreement between a Broker-Dealer and the Auction Agent pursuant to which a Broker-Dealer, among other things, agrees to participate in Auctions as set forth in the Dutch Auction Procedures, as from time to time amended and supplemented.

"Commercial Paper Dealer" shall mean with respect to the Offered Securities, A.G. Edwards & Sons, Inc., or, in lieu thereof, its affiliates or successors, provided that any such entity is a commercial paper dealer.

"Commercial Paper/Treasury Rate" shall mean on any date of determination (i) in the case of any Auction Period of less than 49 days, the interest equivalent of the 30-day rate, (ii) in the case of any Auction Period of 49 days or more but less than 70 days, the interest equivalent of the 60-day rate, (iii) in the case of any Auction Period of 70 days or more but less than 85 days, the arithmetic average of the interest equivalent of the 60-day and 90-day rates, (iv) in the case of any Auction Period of 85 days or more but less than 99 days, the interest equivalent of the 90-day rate, (v) in the case of any Auction Period of 99 days or more but less than 120 days, the arithmetic average of the interest equivalent of the 90-day and 120-day rates, (vi) in the case of any Auction Period of 120 days or more but less than 141 days, the interest equivalent of the 120-day rate, (vii) in the case of any Auction Period of 141 days or more but less than 162 days, the arithmetic average of the interest equivalent of the 120-day and 180-day rates, (viii) in the case of any Auction Period of 162 days or more but less than 183 days, the interest equivalent of the 180-day rate, and (ix) in the case of any Auction Period of 183 days or more, the Treasury Rate with respect to such Auction Period, which rates shall be, in all cases other than the Treasury Rate, rates on commercial paper with the specified maturities placed on behalf of issuers whose corporate bonds are rated Aa by Moody's, or the equivalent of such rating by Moody's, as made available on a discount basis or otherwise by the Federal Reserve Bank of New York for the Business Day immediately preceding such date of determination, or in the event that the Federal Reserve Bank of New York does not make available any such rate, then the arithmetic average of such rates, as quoted on a discount basis or otherwise, by the Commercial Paper Dealer, to the Auction Agent for the close of business on the Business Day immediately preceding such date of determination.

If the Commercial Paper Dealer does not quote a commercial paper rate required to determine the Commercial Paper/Treasury Rate, the Commercial Paper/Treasury Rate shall be determined on the basis of such quotation or quotations furnished by the Substitute Commercial Paper Dealer. For purposes of this definition, the "interest equivalent" of a rate stated on a discount basis (a "discount rate") for commercial paper of a given day's maturity shall be equal to the product of (A) 100 and (B) the quotient (rounded upwards to the next higher one-thousandth (.001) of 1%) of (x) the discount rate (expressed in decimals) and (y) the difference between (1) 1.00 and (2) a fraction the numerator of which shall be the product of the discount rate (expressed in decimals) times the number of days in which such commercial paper matures and the denominator of which shall be 360.

FMPA-POD3-00114 HEARING EXHIBIT - 00000524

"DTC" shall mean The Depository Trust Company, New York, New York, or any substitute securities depository appointed pursuant to the Resolution in connection with the Offered Securities and which is selected by the Agency.

"Dutch Auction Index" on any date of determination, shall mean The Bond Market Association Municipal Swap Index™ most recently released by Municipal Market Data to its subscribers.

"Dutch Auction Procedures" shall mean the procedures set forth in this Appendix H.

"Dutch Auction Rate" shall mean the interest rate to be determined for the Offered Securities pursuant to the Dutch Auction Procedures.

"Dutch Auction Rate Period" shall mean each period during which the Offered Securities accrue interest at a Dutch Auction Rate.

"Event of Default" shall mean any of the events set forth in Appendix C --"Summary of Certain Provisions of the Resolution and Power Supply Contracts – Summary of Certain Provisions of Resolution – Events of Default and Remedies."

"Existing Holder" shall mean, for purposes of each Auction, a person who is listed as the beneficial owner of Offered Securities in the records of the Auction Agent as of the Record Date in respect of the last Interest Payment Date for the Auction Period then ending.

"Hold Order" shall have the meaning set forth below under "Orders by Existing Holders and Potential Holders".

"Interest Payment Date" shall mean the dates shown for each Series on the inside front cover page of this Official Statement as the first interest payment dates and, as to any Offered Security in a Dutch Auction Mode, (1) for an Auction Period of 91 days or less, the Business Day immediately succeeding the last day of such Auction Period and (2) for an Auction Period of more than 91 days, each 13th Tuesday in the case of the Series 2006B-1 Bonds and Series 2006B-2 Bonds, each 13th Thursday in the case of the Series 2006B-3 Bonds, each 13th Monday in the case of the Series 2006B-4 Bonds and each 13th Friday in the case of the Series 2006C Bonds (or if such day is not a Business Day, the next succeeding Business Day) after the first day of such Auction Period and the Business Day immediately succeeding the last day of such Auction Period.

"Market Agent" shall mean with respect to the Offered Securities, the market agent appointed in accordance with the Resolution, initially A.G. Edwards & Sons, Inc., and its successors and their assigns.

"Maximum Dutch Auction Rate" shall mean on any date of determination (i) if such determination is in respect of an Auction with respect to a Standard Auction Period, and is made during a Standard Auction Period, the interest rate per annum equal to the lesser of (A)(i) 10% with respect to the Series 2006B Bonds, or (ii) 12% with respect to the Series 2006C Bonds, and (B) the greater of (a) the Applicable Percentage (Taxable) of the Commercial Paper/Treasury Rate, as determined on such date with respect to a Standard Auction Period and (b) the Applicable Percentage (Tax-Exempt) of the Dutch Auction Index on such date or (ii) if such determination is in respect of an Auction with respect to an Auction Period which is not of the same duration as the Auction Period then ending, the interest rate per annum equal to the lesser of (A)(i) 10% with respect to the Series 2006B Bonds or (ii) 12% with respect to the Series 2006C Bonds and (B) the greatest of (a) the Applicable Percentage (Taxable) of the Commercial Paper/Treasury Rate, as determined on such date with respect to a Standard Auction Period, (b) the Applicable Percentage (Taxable) of the Commercial Paper/Treasury Rate, as determined on such date with respect to the Auction Period, if any, which is proposed to be established, (c) the Applicable Percentage (Taxable) of the Commercial Paper/Treasury Rate, as determined on such date with respect to the Auction Period then ending and (d) the Applicable Percentage (Tax-Exempt) of the Dutch Auction Index on such date.

"Order" shall have the meaning set forth below under "Orders by Existing Holders and Potential Holders".

FMPA-POD3-00115

HEARING EXHIBIT - 00000526

"Overdue Rate" shall mean, on any date of determination, the lesser of (i)(A) 10% with respect to the Series 2006B Bonds, or (B) 12% with respect to the Series 2006C Bonds, and (ii) the Applicable Percentage (determined as if the Offered Securities had a prevailing rating of Below Baa/BBB) of (A) with respect to the Series 2006B Bonds, the Dutch Auction Index on such date, or (B) with respect to the Series 2006C Bonds, the Commercial Paper/Treasury Rate on such date.

"Potential Holder" shall mean any person, including any Existing Holder, who may be interested in acquiring the beneficial ownership of Offered Securities during a Dutch Auction Rate Period or, in the case of an Existing Holder thereof, the beneficial ownership of an additional principal amount of Offered Securities during a Dutch Auction Rate Period.

"Sell Order" shall have the meaning set forth below under "Orders by Existing Holders and Potential Holders".

"Standard Auction Period" initially shall mean an Auction Period of seven days and after the establishment of a different period as described below under "Change of Auction Period" shall mean such different period.

"Submission Deadline" shall mean 1:00 p.m. (New York City time) on any Auction Date or such other time on any Auction Date by which Broker-Dealers are required to submit Orders to the Auction Agent as specified by the Auction Agent from time to time.

"Submission Processing Deadline" shall mean the earlier of (i) 40 minutes after the Submission Deadline and (ii) the time when the Auction Agent begins to disseminate the results of the Auction to Broker-Dealers.

"Submitted Bid" shall have the meaning set forth below under "Determination of Sufficient Clearing Bids, Winning Bid Rate and Dutch Auction Rate".

"Submitted Hold Order" shall have the meaning set forth below under "Determination of Sufficient Clearing Bids, Winning Bid Rate and Dutch Auction Rate".

"Submitted Order" shall have the meaning set forth below under "Determination of Sufficient Clearing Bids, Winning Bid Rate and Dutch Auction Rate".

"Submitted Sell Order" shall have the meaning set forth below under "Determination of Sufficient Clearing Bids, Winning Bid Rate and Dutch Auction Rate".

"Substitute Commercial Paper Dealer" shall mean a commercial paper dealer selected by the Agency, its affiliates or successors.

"Substitute U.S. Government Securities Dealer" shall mean a U.S. government securities dealer selected by the Agency, its affiliates or successors.

"Sufficient Clearing Bids" shall have the meaning set forth below under "Determination of Sufficient Clearing Bids, the Winning Bid Rate and Dutch Auction Rate".

"Treasury Rate" shall mean on any date of determination for any Auction Period, (i) the bond equivalent yield calculated in accordance with prevailing industry convention of the rate on the most recently auctioned direct obligations of the U.S. Government having a maturity at the time of issuance of 364 days or less with a remaining maturity closest to the length of such Auction Period as quoted in *The Wall Street Journal* on such date for the Business Day next preceding such date; or (ii) in the event that any such rate is not published by *The Wall Street Journal*, then the bond equivalent yield calculated in accordance with prevailing industry convention as calculated by reference to the arithmetic average of the bid price quotations of the most recently auctioned direct obligations of the U.S. Government having a maturity at the time of issuance of 364 days or less with a remaining maturity closest to the length of such Auction Period, based on bid price quotations on such date obtained by the Auction Agent from the U.S. Government Securities Dealer; provided, that, if the U.S. Government Securities Dealer does not provide a

HEARING EXHIBIT - 00000527

bid price quotation required to determine the Treasury Rate, the Treasury Rate shall be determined on the basis of the quotation or quotations furnished by the Substitute U.S. Government Securities Dealer.

"U.S. Government Securities Dealer" shall mean with respect to the Offered Securities, A.G. Edwards & Sons, Inc.

"Winning Bid Rate" shall have the meaning set forth below under "Determination of Sufficient Clearing Bids, Winning Bid Rate and Dutch Auction Rate".

The following are the procedures to be used in conducting Dutch Auctions. As a summary, it does not purport to be complete and is qualified in its entirety by reference to the Dutch Auction Procedures set forth in the Resolution. The summary applies separately to each Series of the Offered Securities while it bears interest at the Dutch Auction Rate.

Auction Period-General

During any Dutch Auction Rate Period, the Offered Securities shall accrue interest at the Dutch Auction Rate determined as set forth below. The Dutch Auction Rate for any initial Auction Period immediately after any conversion to a Dutch Auction Rate Period shall be the rate of interest per annum determined and certified to the Trustee (with a copy to the Bond Registrar, Paying Agent and the Agency) by the Market Agent on a date not later than the effective date of such conversion, as the minimum rate of interest which, in the opinion of the Market Agent, would be necessary as of the date of such conversion to market Offered Securities in a secondary market transaction at a price equal to the principal amount thereof, provided that such interest rate shall not exceed the Maximum Dutch Auction Rate. Except for the initial Auction Period, which commences on the date of original issuance of the Offered Securities, and as otherwise provided in the Resolution for any other Auction Period, the Dutch Auction Rate shall be the rate of interest per annum that results from implementation of the Dutch Auction Procedures; provided that such interest rate shall not exceed the Maximum Dutch Auction Rate. Determination of the Dutch Auction Rate pursuant to the Dutch Auction Procedures shall be suspended upon the occurrence of an Event of Default consisting of the failure to pay principal of, or interest on, the Offered Securities when due, which is not cured by the Bond Insurer. Upon the occurrence of such an Event of Default on any Auction Date, which is not cured by the Bond Insurer, no Auction will be held, all Submitted Bids and Submitted Sell Orders shall be rejected, the existence of Sufficient Clearing Bids shall be of no effect and the Dutch Auction Rate shall be equal to the Overdue Rate as determined on and as of the immediately preceding Auction Date for each Auction Period commencing after the occurrence of such Event of Default to and including the Auction Period, if any, during which or commencing less than two Business Days after the earlier of (A) such Event of Default has been cured or waived and (B) the first date on which all of the following conditions shall have been satisfied:

(1) no default shall have occurred and be continuing under the Bond Insurance Policy (the satisfaction of such condition to be conclusively evidenced, absent manifest error, to each of the Trustee and the Auction Agent by a certificate of a duly authorized officer of the Bond Insurer to such effect delivered to such entity);

(2) the Bond Insurer shall have delivered to the Auction Agent an instrument, satisfactory in form and substance to the Auction Agent, containing (x) an unconditional agreement of the Bond Insurer to furnish to the Auction Agent amounts sufficient to pay all fees of the Broker-Dealers, as provided in the Broker-Dealer Agreements, and of the Auction Agent, (y) such other agreements and representations as the Auction Agent shall reasonably require and (z) a direction not to suspend, or to resume, the implementation of the Dutch Auction Procedures, as the case may be; and

(3) the Auction Agent shall have advised the Trustee that the Auction Agent has been directed by the Bond Insurer not to suspend, or to resume, the implementation of the Dutch Auction Procedures.

HEARING EXHIBIT - 00000528

The Dutch Auction Rate for any Auction Period commencing after certificates representing the Offered Securities have been distributed as described below under "DTC Required During Dutch Auction Rate Mode; Limitations on Transfer" shall be equal to the Maximum Dutch Auction Rate on each Auction Date.

Except as described above, in the event the Auction Agent shall fail to calculate or, for any reason, fails to provide the Auction Rate for any Auction Period, (i) if the preceding Auction Period was a period of 35 days or less, the new Auction Period shall be the same as the preceding Auction Period and the Dutch Auction Rate for the new Auction Period shall be the same as the Dutch Auction Rate for the preceding Auction Period, and (ii) if the preceding Auction Period was a period of greater than 35 days, the preceding Auction Period shall be extended to the next seventh day following the day that would have been the last day of such Auction Period had it not been extended (or if such seventh day is not followed by a Business Day then to the next succeeding day which is followed by a Business Day) and the Dutch Auction Rate in effect for the preceding Auction Period will continue in effect for the Auction Period as so extended. In the event the Auction Period is extended as set forth in clause (ii) of the preceding sentence, an Auction shall be held on the last Business Day of the Auction Period as so extended to take effect for an Auction Period beginning on the Business Day immediately following the last day of the Auction Period as extended which Auction Period will end on the date it would otherwise have ended on had the prior Auction Period not been extended.

Auction Periods may be changed at any time as described below under "Change of Auction Period" unless an Event of Default consisting of the failure to pay principal of, or interest on, the Offered Securities when due has occurred and has not been cured or waived. Each such Auction Period shall be a Standard Auction Period unless a different Auction Period is established and each Auction Period which immediately succeeds an Auction Period that is not a Standard Auction Period shall be a Standard Auction Period unless a different Auction Period is established as described below under "Change of Auction Period".

The Market Agent shall from time to time with the consent of the Bond Insurer, which shall not be unreasonably withheld, revise either upward or downward any or all of the percentages set forth in the definitions of "Applicable Percentage" or the percentages set forth in clause (ii) of the definition of "All Hold Rate" in order that such percentages take into account any amendment to the Code or other statute enacted by the Congress of the United States or any temporary proposed or final regulation promulgated by the United States Treasury, after the date of issuance of the Offered Securities which (a) changes or would change any deduction, credit or other allowance allowable in computing liability for any federal tax with respect to, or (b) imposes, or would impose or increases or would increase any federal tax (including, but not limited to, preference or excise taxes) upon, any interest on a governmental obligation the interest on which is excluded from federal gross income under Section 103 of the Code. In making any such adjustment, the Market Agent shall take the following factors into account, as in existence both before and after such change of tax law: (1) short-term taxable and tax-exempt market rates and indices of such short-term rates; (2) the market supply and demand for short-term tax-exempt securities; (3) yield curves for short-term and long-term tax-exempt securities or obligations having a credit rating that is comparable to the Offered Securities; (4) general economic conditions; and (5) economic and financial factors present in the securities industry that may affect or that may be relevant to the Offered Securities. The Market Agent shall give notice of any such increase by means of a written notice delivered at least two Business Days prior to the Auction Date on which such increase is proposed to be effective to the Trustee, the Auction Agent, the Agency and DTC.

Change of Auction Period

During a Dutch Auction Rate Period, the Agency may change the length of a single Auction Period or the Standard Auction Period by means of a written notice delivered at least 20 days but not more than 60 days prior to the Auction Date for such Auction Period to the Trustee, the Broker-Dealer, the Market Agent, the Bond Insurer, the Auction Agent and DTC. Any Auction Period or Standard Auction Period established pursuant to the Dutch Auction Procedures may not exceed 364 days in duration and shall apply to all Offered Securities then bearing interest at a Dutch Auction Rate. The length of an Auction Period or the Standard Auction Period may not be changed as described herein unless Sufficient Clearing Bids existed at both the Auction immediately preceding the date the notice of such change was given and the Auction immediately preceding such changed Auction Period.

The change in length of an Auction Period or the Standard Auction Period shall take effect only if (i) the Trustee and the Auction Agent receive, by 11:00 a.m. (New York City time) on the Business Day immediately

FMPA-POD3-00118

HEARING EXHIBIT - 00000529

preceding the Auction Date for such Auction Period, a certificate from the Agency by telecopy or similar means, authorizing the change in the Auction Period or the Standard Auction Period, which shall be specified in such certificate, and confirming that Bond Counsel expects to be able to give an opinion on the first day of such Auction Period to the effect that the change in the Auction Period is authorized by the Resolution, is permitted under the Act and will not have an adverse effect on the exclusion of interest on the Offered Securities from gross income for federal income tax purposes, (ii) Sufficient Clearing Bids exist at the Auction on the Auction Date for such Auction Period, and (iii) the Trustee, the Bond Insurer and the Auction Agent receive by 9:30 a.m. (New York City time) on the first day of such Auction Period, an opinion of Bond Counsel to the effect that the change in the Auction Period is authorized by the Resolution, is permitted under the Act and, in the case of the Series 2006B Bonds, will not have an adverse effect on the exclusion of interest on the Series 2006B Bonds from gross income for federal income tax purposes to which a Holder of the Series 2006B Bonds would otherwise be entitled. If the condition referred to in (i) above is not met, the Dutch Auction Rate for the next succeeding Auction Period shall be determined pursuant to the Dutch Auction Procedures and the next succeeding Auction Period shall be a Standard Auction Period. If any of the conditions referred to in (ii), or (iii) above is not met, the Dutch Auction Rate for the next succeeding Auction Period shall equal the Maximum Dutch Auction Rate as determined as of the Auction Date for such Standard Auction Period.

Failed Conversion

In the event of a failure to convert the Offered Securities to an Interest Mode other than a Dutch Auction Mode, the Dutch Auction Rate for the next succeeding Auction Period shall equal the Maximum Dutch Auction Rate as determined as of the Auction Date and the Auction Period shall be a Standard Auction Period.

Orders by Existing Holders and Potential Holders

Subject to the provisions described above under "Auction Period-General", Auctions shall be conducted on each Auction Date in the manner described under this heading and in the remainder of this Appendix H prior to the Submission Deadline on each Auction Date during a Dutch Auction Rate Period:

(i) each Existing Holder may submit to the Broker-Dealer information as to:

(A) the principal amount of Offered Securities, if any, held by such Existing Holder which such Existing Holder desires to continue to hold without regard to the Dutch Auction Rate for the next succeeding Auction Period;

(B) the principal amount of Offered Securities, if any, held by such Existing Holder which such Existing Holder offers to sell if the Dutch Auction Rate for the next succeeding Auction Period shall be less than the rate per annum specified by such Existing Holder; and

(C) the principal amount of Offered Securities, if any, held by such Existing Holder which such Existing Holder offers to sell without regard to the Dutch Auction Rate for the next succeeding Auction Period; and

(ii) one or more Broker-Dealers may contact Potential Holders to determine the principal amount of Offered Securities which each such Potential Holder offers to purchase if the Dutch Auction Rate for the next succeeding Auction Period shall not be less than the interest rate per annum specified by such Potential Holder.

For the purposes hereof, the communication to a Broker-Dealer of information referred to in clause (i)(A), (i)(B) or (i)(C) or clause (ii) above is hereinafter referred to as an "Order" and each Existing Holder and Potential Holder placing an Order is hereinafter referred to as a "Bidder"; an Order containing the information referred to in clause (i)(A) above is hereinafter referred to as a "Hold Order"; an Order containing the information referred to in clause (i)(B) or clause (ii) above is hereinafter referred to as a "Bid"; and an Order containing the information referred to in clause (i)(C) above is hereinafter referred to as a "Sell Order":

HEARING EXHIBIT - 00000530

(i) Subject to the provisions of "Submission of Orders by Broker Dealers to Auction Agent" below, a Bid by an Existing Holder shall constitute an offer to sell:

(A) the principal amount of Offered Securities specified in such Bid if the Dutch Auction Rate determined pursuant to the Dutch Auction Procedures on such Auction Date shall be less than the interest rate per annum specified therein; or

(B) such principal amount or a lesser principal amount of Offered Securities to be determined as set forth in clause (iv) below under "Acceptance and Rejection of Submitted Bids and Submitted Sell Orders and Allocation of Auction Offered Securities" below if the Dutch Auction Rate determined pursuant to the Dutch Auction Procedures on such Auction Date shall be equal to the interest rate per annum specified therein; or

(C) such principal amount if the interest rate per annum specified therein shall be higher than the Maximum Dutch Auction Rate, if Sufficient Clearing Bids exist, or such principal amount or a lesser principal amount of Offered Securities to be determined in clause (iii) below under "Acceptance and Rejection of Submitted Bids and Submitted Sell Orders and Allocation of Auction Offered Securities" below if such specified rate shall be higher than the Maximum Dutch Auction Rate and Sufficient Clearing Bids do not exist.

(ii) Subject to the provisions set forth below under "Submission of Orders by Broker Dealers to Auction Agent", a Sell Order by an Existing Holder shall constitute an offer to sell:

(A) the principal amount of Offered Securities specified in such Sell Order; or

(B) such principal amount or a lesser principal amount of Offered Securities as set forth in clause (iii) below under "Acceptance and Rejection of Submitted Bids and Submitted Sell Orders and Allocation of Auction Offered Securities" if Sufficient Clearing Bids do not exist.

(iii) Subject to the provisions described in "Submission of Orders by Broker-Dealers to Auction Agent", below, a Bid by a Potential Holder shall constitute an offer to purchase:

(A) the principal amount of Offered Securities specified in such Bid if the Dutch Auction Rate determined on such Auction Date shall be higher than the rate specified therein; or

(B) such principal amount or a lesser principal amount of Offered Securities as set forth in clause (v) below under "Acceptance and Rejection of Submitted Bids and Submitted Sell Orders and Allocation of Auction Offered Securities" if the Dutch Auction Rate determined on such Auction Date shall be equal to such specified rate.

(iv) Any order submitted by an Existing Holder or Potential Holder shall become irrevocable upon the occurrence of the Submission Deadline.

Submission of Orders by Broker-Dealers to Auction Agent

During a Dutch Auction Rate Period each Broker-Dealer shall submit in writing or through the Auction Agent's auction processing system to the Auction Agent prior to the Submission Deadline (or after the Submission Deadline and prior to the Submission Processing Deadline if the order was (i) received by the Broker-Dealer from Existing Holders or Potential Holders prior to the Submission Deadline or (ii) initiated internally by the Broker-Dealer for its own account prior to the Submission Deadline) on each Auction Date all Orders obtained by such Broker-Dealer, for the Auction to be conducted on each Auction Date designating each Order as either on behalf of an Existing Holder or a Potential Holder, and specifying with respect to each such Order:

(i) the aggregate principal amount of Offered Securities that are subject to such Order;

FMPA-POD3-00120

HEARING EXHIBIT - 00000531

(ii) to the extent that such Bidder is an Existing Holder:

(A) the principal amount of Offered Securities, if any, subject to any Hold Order placed by such Existing Holder;

(B) the principal amount of Offered Securities, if any, subject to any Bid placed by such Existing Holder and the rate specified in such Bid; and

(C) the principal amount of Offered Securities, if any, subject to any Sell Order placed by such Existing Holder; and

(iii) to the extent such Bidder is a Potential Holder, the rate specified in such Potential Holder's Bid.

If any rate specified in any Bid contains more than three figures to the right of the decimal point, the Auction Agent shall round such rate up to the next highest one thousandth (.001) of 1%.

If an Order or Orders covering all Offered Securities held by an Existing Holder is not submitted to the Auction Agent prior to the Submission Deadline, the Auction Agent shall deem a Hold Order to have been submitted on behalf of such Existing Holder covering the principal amount of Offered Securities held by such Existing Holder and not subject to Orders submitted to the Auction Agent, except in the event of a conversion to a new Dutch Auction Rate Period in which case the Auction Agent shall deem a Sell Order to have been submitted. Neither the Agency, the Trustee nor the Auction Agent shall be responsible for any failure of a Broker-Dealer to submit an Order to the Auction Agent on behalf of any Existing Holder or Potential Holder.

If any Existing Holder submits through a Broker-Dealer to the Auction Agent one or more Orders covering in the aggregate more than the principal amount of Offered Securities held by such Existing Holder, such Orders shall be considered valid as follows and in the following order of priority:

(i) all Hold Orders shall be considered valid, but only up to and including the principal amount of Offered Securities held by such Existing Holder, and, if the aggregate principal amount of Offered Securities subject to such Hold Orders exceeds the aggregate principal amount of Offered Securities held by such Existing Holder, the aggregate principal amount of Offered Securities subject to each such Hold Order shall be reduced pro rata to cover the aggregate principal amount of Offered Securities held by such Existing Holder;

(ii) (A) any Bid shall be considered valid up to and including the excess of the principal amount of Offered Securities held by such Existing Holder over the aggregate principal amount of Offered Securities subject to any Hold Orders referred to in paragraph (i) above;

(B) subject to clause (A) above, if more than one Bid with the same rate is submitted on behalf of such Existing Holder and the aggregate principal amount of Offered Securities subject to such Bids is greater than such excess, such Bids shall be considered valid up to and including the amount of such excess, and the principal amount of Offered Securities subject to each Bid with the same rate shall be reduced pro rata to cover the principal amount of Offered Securities equal to such excess;

(C) subject to clauses (A) and (B) above, if more than one Bid with different rates is submitted on behalf of such Existing Holder, such Bids shall be considered valid in the ascending order of their respective rates until the highest rate is reached at which such excess exists and then at such rate up to and including the amount of such excess; and

(D) in any such event, the aggregate principal amount of Offered Securities, if any, subject to Bids not valid under this paragraph (ii) shall be treated as the subject of a Bid by a Potential Holder at the rate therein specified; and

FMPA-POD3-00121

HEARING EXHIBIT 00000532

(iii) all Sell Orders shall be considered valid up to and including the excess of the principal amount of Offered Securities held by such Existing Holder over the aggregate principal amount of Offered Securities subject to valid Hold Orders referred to in paragraph (i) and valid Bids referred to in paragraph (ii) above.

If more than one Bid is submitted on behalf of any Potential Holder, each Bid submitted with the same rate may be aggregated and considered a single Bid and each Bid submitted with a different rate shall be considered a separate Bid with the rate and the principal amount specified therein.

Each Order submitted to the Auction Agent after the Submission Deadline and prior to the Submission Processing Deadline shall constitute a representation by the Broker-Dealer that such Order was (i) received from an Existing Holder or Potential Holder prior to the Submission Deadline or (ii) initiated internally by the Broker-Dealer for its own account prior to the Submission Deadline.

Any Bid or Sell Order submitted by an Existing Holder covering an aggregate principal amount of Offered Securities not equal to $25,000 or an integral multiple of $5,000 in excess thereof shall be rounded down to the nearest integral multiple of $25,000. Any Bid submitted by a Potential Holder covering an aggregate principal amount of Offered Securities not equal to $25,000 or an integral multiple of $5,000 in excess thereof shall be rounded down to the nearest integral multiple of $25,000.

Determination of Sufficient Clearing Bids, Winning Bid Rate and Dutch Auction Rate

Not earlier than the Submission Deadline on each Auction Date during the Dutch Auction Rate Period, the Auction Agent shall assemble all valid Orders submitted or deemed submitted to it by the Broker-Dealers (each such Order as submitted or deemed submitted by a Broker-Dealer being hereinafter referred to as a "Submitted Hold Order", a "Submitted Bid" or a "Submitted Sell Order", as the case may be, or as a "Submitted Order") and shall determine:

(i) the excess of the total principal amount of Offered Securities over the aggregate principal amount of Offered Securities subject to Submitted Hold Orders (such excess being hereinafter referred to as the "Available Auction Offered Securities"); and

(ii) from the Submitted Orders whether the aggregate principal amount of Offered Securities subject to Submitted Bids by Potential Holders specifying one or more rates equal to or lower than the Maximum Dutch Auction Rate exceeds or is equal to the sum of:

(A) the aggregate principal amount of Offered Securities subject to Submitted Bids by Existing Holders specifying one or more rates higher than the Maximum Dutch Auction Rate; and

(B) the aggregate principal amount of Offered Securities subject to Submitted Sell Orders; (in the event of such excess or such equality exists (other than because the sum of the principal amounts of Offered Securities in clauses (A) and (B) above is zero because all of the Offered Securities are subject to Submitted Hold Orders), such Submitted Bids in clause (ii) above are hereinafter referred to collectively as "Sufficient Clearing Bids"); and

(iii) if Sufficient Clearing Bids exist, the lowest rate specified in the Submitted Bids (the "Winning Bid Rate") which if:

(A) (y) each Submitted Bid from Existing Holders specifying such lowest rate and (z) all other Submitted Bids from Existing Holders specifying lower rates were rejected, thus requiring such Existing Holders to continue to hold the principal amount of Offered Securities subject to such Submitted Bids; and

(B) (y) each Submitted Bid from Potential Holders specifying such lowest rate and (z) all other Submitted Bids from Potential Holders specifying lower rates were accepted,

HEARING EXHIBIT - 00000533

would result in such Existing Holders described in clause (A) above continuing to hold an aggregate principal amount of Offered Securities which, when added to the aggregate principal amount of Offered Securities to be purchased by such Potential Holders described in clause (B) above, would equal not less than the Available Auction Bonds.

Promptly after the Auction Agent has made the determinations pursuant to the first paragraph of this section, the Auction Agent by telecopy, confirmed in writing, shall advise the Agency and the Trustee of the Maximum Dutch Auction Rate and the All Hold Rate and the components thereof on the Auction Date and, based on such determinations, the Dutch Auction Rate for the next succeeding Auction Period as follows:

(i) if Sufficient Clearing Bids exist, that the Dutch Auction Rate for the next succeeding Auction Period therefor shall be equal to the Winning Bid Rate so determined;

(ii) if Sufficient Clearing Bids do not exist (other than because all of the Offered Securities are the subject of Submitted Hold Orders), that the Dutch Auction Rate for the next succeeding Auction Period therefor shall be equal to the Maximum Dutch Auction Rate; and

(iii) if all of the Offered Securities are subject to Submitted Hold Orders, that the Dutch Auction Rate for the next succeeding Auction Period therefor shall be equal to the All Hold Rate.

Acceptance and Rejection of Submitted Bids and Submitted Sell Orders and Allocation of Auction Offered Securities

During a Dutch Auction Rate Period, Existing Holders shall continue to hold the principal amounts of Offered Securities that are subject to Submitted Hold Orders, and, based on the determinations made pursuant to the first paragraph of "Determination of Sufficient Clearing Bids, Winning Bid Rate and Dutch Auction Rate", the Submitted Bids and Submitted Sell Orders shall be accepted or rejected and the Auction Agent shall take such other actions as are set forth below:

If Sufficient Clearing Bids have been made, all Submitted Sell Orders shall be accepted and subject to the Auction Procedures, Submitted Bids shall be accepted or rejected as follows in the following order of priority and all other Submitted Bids shall be rejected:

(i) Existing Holders' Submitted Bids specifying any rate that is higher than the Winning Bid Rate shall be accepted, thus requiring each such Existing Holder to sell the aggregate principal amount of Offered Securities subject to such Submitted Bids;

(ii) Existing Holders' Submitted Bids specifying any rate that is lower than the Winning Bid Rate shall be rejected, thus requiring each such Existing Holder to continue to hold the aggregate principal amount of Offered Securities subject to such Submitted Bids;

(iii) Potential Holders' Submitted Bids specifying any rate that is lower than the Winning Bid Rate shall be accepted, thus requiring each such Potential Holder to purchase the aggregate principal amount of Offered Securities subject to such Submitted Bids;

(iv) each Existing Holder's Submitted Bid specifying a rate that is equal to the Winning Bid Rate shall be rejected, thus requiring such Existing Holder to continue to hold the aggregate principal amount of Offered Securities subject to such Submitted Bid, unless the aggregate principal amount of Offered Securities subject to all such Submitted Bids shall be greater than the principal amount of Offered Securities (the "remaining principal amount") equal to the excess of the Available Auction Offered Securities over the aggregate principal amount of the Offered Securities subject to Submitted Bids described in paragraphs (ii) and (iii) immediately above, in which event such Submitted Bid of such Existing Holder shall be rejected in part, and such Existing Holder shall be required to continue to hold the principal amount of Offered Securities subject to such Submitted Bid, but only in an amount equal to the principal amount of Offered Securities obtained by multiplying the remaining principal amount by a fraction, the numerator of which shall be the principal amount of Offered Securities held by such

HEARING EXHIBIT 00000534

Existing Holder subject to such Submitted Bid and the denominator of which shall be the sum of the principal amounts of Offered Securities subject to such Submitted Bids made by all such Existing Holders that specified a rate equal to the Winning Bid Rate; and

(v) each Potential Holder's Submitted Bid specifying a rate that is equal to the Winning Bid Rate shall be accepted but only in an amount equal to the principal amount of Offered Securities obtained by multiplying the excess of the Available Auction Bonds over the aggregate principal amount of Offered Securities subject to Submitted Bids described in paragraphs (ii), (iii) and (iv) immediately above, by a fraction the numerator of which shall be the aggregate principal amount of Offered Securities subject to such Submitted Bid of such Potential Holder and the denominator of which shall be the sum of the principal amount of Offered Securities subject to Submitted Bids made by all such Potential Holders that specified a rate equal to the Winning Bid Rate.

If Sufficient Clearing Bids have not been made (other than because all of the Offered Securities are subject to Submitted Hold Orders), subject to the Auction Procedures, Submitted Orders shall be accepted or rejected as follows in the following order of priority and all other Submitted Bids shall be rejected:

(i) Existing Holders' Submitted Bids specifying any rate that is equal to or lower than the Maximum Dutch Auction Rate shall be rejected, thus requiring each such Existing Holder to continue to hold the aggregate principal amount of Offered Securities subject to such Submitted Bids;

(ii) Potential Holders' Submitted Bids specifying any rate that is equal to or lower than the Maximum Dutch Auction Rate shall be accepted, thus requiring each such Potential Holder to purchase the aggregate principal amount of Offered Securities subject to such Submitted Bids; and

(iii) each Existing Holder's Submitted Bid specifying any rate that is higher than the Maximum Dutch Auction Rate and the Submitted Sell Orders of each Existing Holder shall be accepted, thus requiring each Existing Holder that submitted any such Submitted Bid or Submitted Sell Order to sell the Offered Securities subject to such Submitted Bid or Submitted Sell Order, but in both cases only in an amount equal to the aggregate principal amount of Offered Securities obtained by multiplying the aggregate principal amount of Offered Securities subject to Submitted Bids described above in subparagraph (ii) by a fraction, the numerator of which shall be the aggregate principal amount of Offered Securities held by such Existing Holder subject to such Submitted Bid or Submitted Sell Order and the denominator of which shall be the aggregate principal amount of Outstanding Auction Offered Securities subject to all such Submitted Bids and Submitted Sell Orders.

If all Offered Securities are subject to Submitted Hold Orders, all Submitted Bids shall be rejected.

If, as a result of the Auction Procedures, any Existing Holder would be required to sell, or any Potential Holder would be required to purchase, a principal amount of Offered Securities that is not equal to $25,000 or an integral multiple thereof, the Auction Agent shall, in such manner as, in its sole discretion, it shall determine, round down the principal amount of such Offered Securities to be purchased or sold by any Existing Holder or Potential Holder so that the principal amount purchased or sold by each Existing Holder or Potential Holder shall be equal to $25,000 or an integral multiple thereof.

If, as a result of the Auction Procedures, any Potential Holder would be required to purchase less than $25,000 in aggregate principal amount of Offered Securities, the Auction Agent shall, in such manner as, in its sole discretion, it shall determine, allocate Offered Securities for purchase among Potential Holders so that only Offered Securities in principal amounts of $25,000 or an integral multiple thereof are purchased by any Potential Holder, even if such allocation results in one or more of such Potential Holders not purchasing any Offered Securities.

Based on the results of each Auction, the Auction Agent shall determine the aggregate principal amounts of Offered Securities to be purchased and the aggregate principal amounts of Offered Securities to be sold by Potential Holders and Existing Holders on whose behalf each Broker-Dealer submitted Bids or Sell Orders and, with respect to each Broker-Dealer, to the extent that such amounts differ, determine to which other Broker-Dealer or Broker-Dealers acting for one or more purchasers of Offered Securities such Broker-Dealer shall deliver, or from which

FMPA-POD3-00124

HEARING EXHIBIT 00000536

other Broker-Dealer or Broker-Dealers acting for one or more sellers of Offered Securities such Broker-Dealer shall receive, as the case may be, Offered Securities.

Settlement Procedures

(a) Not later than 3:00 p.m., New York City time, on each Auction Date, the Auction Agent shall notify by telephone each Broker-Dealer that participated in the Auction held on such Auction Date and submitted an Order on behalf of an Existing Holder or Potential Holder of

(i) the Dutch Auction Rate fixed for the next Auction Period;

(ii) whether there were Sufficient Clearing Bids in such Auction;

(iii) if such Broker-Dealer submitted a Bid or a Sell Order on behalf of an Existing Holder (a "Seller's Broker-Dealer"), whether such Bid was accepted or rejected, in whole or in part, and the principal amount of Offered Securities, if any, to be sold by such Existing Holder;

(iv) if such Broker-Dealer submitted a Bid on behalf of a Potential Holder (a "Buyer's Broker-Dealer"), whether such Bid was accepted or rejected, in whole or in part, and the principal amount of Offered Securities, if any, to be purchased by such Potential Holder;

(v) if the aggregate principal amount of Offered Securities to be sold by all Existing Holders on whose behalf such Broker-Dealer submitted a Bid or a Sell Order exceeds the aggregate principal amount of Offered Securities to be purchased by all Potential Holders on whose behalf such Broker-Dealer submitted a Bid, the name or names of one or more Buyer's Broker-Dealers (and the name of the Agent Member, if any, of each such Buyer's Broker-Dealer) acting for one or more purchasers of such excess principal amount of Offered Securities and the principal amount of Offered Securities to be purchased from one or more Existing Holders on whose behalf such Broker-Dealer acted by one or more Potential Holders on whose behalf each of such Buyer's Broker-Dealers acted;

(vi) if the principal amount of Offered Securities to be purchased by all Potential Holders on whose behalf such Broker-Dealer submitted a Bid exceeds the principal amount of Offered Securities to be sold by all Existing Holders on whose behalf such Broker-Dealer submitted a Bid or a Sell Order, the name or names of one or more Seller's Broker-Dealers (and the name of the Agent Member, if any, of each such Seller's Broker-Dealer) acting for one or more sellers of such excess principal amount of Offered Securities and the principal amount of Offered Securities to be sold to one or more Potential Holders on whose behalf such Broker-Dealer acted by one or more Existing Holders on whose behalf each of such Seller's Broker-Dealers acted; and

(vii) the Auction Date for the next succeeding Auction.

(b) On each Auction Date, each Broker-Dealer that submitted an Order on behalf of any Existing Holder or Potential Holder shall:

(i) advise each Existing Holder and Potential Holder on whose behalf such Broker-Dealer submitted a Bid or Sell Order in the Auction on such Auction Date whether such Bid or Sell Order was accepted or rejected, in whole or in part;

(ii) in the case of a Broker-Dealer that is a Buyer's Broker-Dealer, advise each Potential Holder on whose behalf such Broker-Dealer submitted a Bid that was accepted, in whole or in part, to instruct such Potential Holder's Agent Member to pay to such Broker-Dealer (or its Agent Member) through DTC the amount necessary to purchase the principal amount of Offered Securities to be purchased pursuant to such Bid against receipt of such Offered Securities;

(iii) in the case of a Broker-Dealer that is a Seller's Broker-Dealer, instruct each Existing Holder on whose behalf such Broker-Dealer submitted a Sell Order that was accepted, in whole or in part, or a Bid that was accepted, in whole or in part, to instruct such Existing Holder's Agent Member to deliver to such Broker-

FMPA-POD3-00125

HEARING EXHIBIT 00000536

Dealer (or its Agent Member) through DTC the principal amount of Offered Securities to be sold pursuant to such Order against payment therefor;

(iv) advise each Existing Holder on whose behalf such Broker-Dealer submitted an Order and each Potential Holder on whose behalf such Broker-Dealer submitted a Bid of the Auction Rate for the next Auction Period;

(v) advise each Existing Holder on whose behalf such Broker-Dealer submitted an Order of the next Auction Date; and

(vi) advise each Potential Holder on whose behalf such Broker-Dealer submitted a Bid that was accepted, in whole or in part, of the next Auction Date.

(c) On the basis of the information provided to it pursuant to paragraph (a) above, each Broker-Dealer that submitted a Bid or Sell Order in an Auction is required to allocate any funds received by it in connection with such Auction pursuant to paragraph (b)(ii) above, and any Offered Securities received by it in connection with such Auction pursuant to paragraph(b)(iii) above among the Potential Holders, if any, on whose behalf such Broker-Dealer submitted Bids, the Existing Holders, if any, on whose behalf such Broker-Dealer submitted Bids or Sell Orders in such Auction, and any Broker-Dealer identified to it by the Auction Agent following such Auction pursuant to paragraph (a)(v) or (a)(vi) above.

(d) On each Auction Date:

(i) each Potential Holder and Existing Holder with an Order in the Auction on such Auction Dates shall instruct its Agent Member as provided in (b)(ii) or (iii) above, as the case may be;

(ii) each Seller's Broker-Dealer that is not an Agent Member of DTC shall instruct its Agent Member to (A) pay through DTC to the Agent Member of the Existing Holder delivering Offered Securities to such Broker-Dealer following such Auction pursuant to (b)(iii) above the amount necessary to purchase such Offered Securities against receipt of such Offered Securities, and (B) deliver such Offered Securities through DTC to a Buyer's Broker-Dealer (or its Agent Member) identified to such Seller's Broker-Dealer pursuant to (a)(v) above against payment therefor; and

(iii) each Buyer's Broker-Dealer that is not an Agent Member of DTC shall instruct its Agent Member to (A) pay through DTC to a Seller's Broker-Dealer (or its Agent Member) identified following such Auction pursuant to (a)(vi) above the amount necessary to purchase the Offered Securities to be purchased pursuant to (b)(ii) above against receipt of such Offered Securities, and (B) deliver such Offered Securities through DTC to the Agent Member of the purchaser thereof against payment therefor.

(e) On the Business Day following each Auction Date:

(i) each Agent Member for a Bidder in the Auction on such Auction Date referred to in (d)(i) above shall instruct DTC to execute the transactions described under (b)(ii) or (iii) above for such Auction, and DTC shall execute such transactions;

(ii) each Seller's Broker-Dealer or its Agent Member shall instruct DTC to execute the transactions described in (d)(ii) above for such Auction, and DTC shall execute such transactions; and

(iii) each Buyer's Broker-Dealer or its Agent Member shall instruct DTC to execute the transactions described in (d)(iii) above for such Auction, and DTC shall execute such transactions.

(f) If an Existing Holder selling Offered Securities in an Auction fails to deliver such Offered Securities (by authorized book entry), a Broker-Dealer may deliver to the Potential Holder on behalf of which it submitted a Bid that was accepted a principal amount of Offered Securities that is less than the principal amount of Offered Securities that otherwise was to be purchased by such Potential Holder. In such event, the principal amount

HEARING EXHIBIT - 00000537

of Offered Securities to be delivered shall be determined solely by such Broker-Dealer. Delivery of such lesser principal amount of Offered Securities shall constitute good delivery. Notwithstanding the foregoing terms of this paragraph (f), any delivery or non-delivery of Offered Securities which shall represent any departure from the results of an Auction, as determined by the Auction Agent, shall be of no effect unless and until the Auction Agent shall have been notified of such delivery or non-delivery in accordance with the provisions of the Auction Agent Agreement and the Broker-Dealer Agreements.

DTC Required During Dutch Auction Rate Mode; Limitations on Transfer

Except as otherwise provided herein, the Offered Securities accruing interest at a Dutch Auction Rate shall be registered in the name of DTC or its nominee and ownership thereof shall be maintained in book-entry-only form by DTC for the account of the Agent Members thereof.

If at any time DTC notifies the Agency that it is unwilling or unable to continue as owner of Offered Securities or if at any time DTC shall no longer be registered or in good standing under the Securities Exchange Act of 1934, as amended, or other applicable statute or regulation and a successor to DTC is not appointed by the Agency within 90 days after the Agency receives notice or become aware of such condition, as the case may be, the Agency shall execute and the Trustee shall authenticate and deliver certificates representing the Offered Securities. Offered Securities issued as described herein shall be registered in such names and authorized denominations as DTC, pursuant to instructions from the Agent Members or otherwise, shall instruct the Agency and the Trustee. The Trustee shall deliver the Offered Securities to the persons in whose names such Offered Securities are so registered on the Business Day immediately preceding the first day of an Auction Period.

So long as the ownership of the Offered Securities is maintained in book-entry-only form by DTC, an Existing Holder may sell, transfer or otherwise dispose of Offered Securities only pursuant to a Bid or Sell Order placed in an Auction or to or through a Broker-Dealer, provided that (i) sale, transfer or other disposition of Bonds in a Dutch Auction Rate Mode from a customer of a Broker-Dealer who is listed on the records of that Broker-Dealer as the holder of such Bonds to that Broker-Dealer or another customer of that Broker-Dealer shall not be deemed to be a sale, transfer or other disposition for purposes of this sentence if such Broker-Dealer remains the Existing Holder of Bonds so sold, transferred or disposed of immediately, after such sale, transfer, or disposition and (ii) in the case of all transfers other than pursuant to Auctions, such Existing Holder, its Broker-Dealer or its Agent Member advises the Auction Agent of such transfer.

The Auction Agent shall calculate the Maximum Dutch Auction Rate on each Auction Date. If the ownership of the Offered Securities is no longer maintained in book-entry-only form by DTC, the Trustee shall calculate the Maximum Dutch Auction Rate on the Business Day immediately preceding the first day of each Auction Period commencing after the delivery of certificates representing the Offered Securities. If an Event of Default consisting of the failure to pay principal of, or interest on, the Offered Securities when due shall have occurred, which is not cured by the Bond Insurer, the Trustee, upon notice thereof; shall calculate the Overdue Rate on the first day of each Auction Period commencing, after the occurrence of such Event of Default to and including the Auction Period, if any, commencing less than two Business Days after all such Events of Default are cured.

In the event that the Offered Securities while in the Dutch Auction Mode bear interest at the Maximum Dutch Auction Rate or the Overdue Rate for a period of 70 consecutive days, FMPA shall, unless otherwise directed in writing by the Bond Insurer, immediately commence to use its best efforts to convert all Offered Securities then Outstanding to a Fixed Mode and to remarket all such Offered Securities in such Fixed Mode as soon as practicable.

FMPA-POD3-00127

HEARING EXHIBIT - 00000538

[This Page Intentionally Left Blank]

HEARING EXHIBIT - 00000539

[This Page Intentionally Left Blank]

HEARING EXHIBIT - 00000540

[This Page Intentionally Left Blank]

HEARING EXHIBIT - 00000541



Moody's Investors Service

99 Church Street
New York, New York 10007

Maria Matesanz
Senior Vice President - Team Leader
Infrastructure Finance Team
Tel: 1.212.553.7241
Fax: 1.212.553.4919
maria.matesanz@moodys.com

March 17, 2006

Mr. Mary Ann Davis
Director Of Finance
Florida Municipal Power Agency
8553 Commodity Circle
Orlando, FL 32819

Dear Mr. Davis:

We wish to inform you that on March 08, 2006, Moody's Investors Service has assigned a rating of A1 to Florida Municipal Power Agency's Series 2006 A, B and C. Our outlook on the rating is stable.

In order for us to maintain the currency of our ratings, we request that you provide ongoing disclosure, including annual financial and statistical information.

Moody's will monitor this rating and reserves the right, at its sole discretion, to revise or withdraw this rating at any time in the future.

The rating, as well as any revisions or withdrawals thereof, will be publicly disseminated by Moody's through normal print and electronic media and in response to verbal requests to Moody's ratings desk.

Should you have any questions regarding the above, please do not hesitate to contact me or the analyst assigned to this transaction, Daniel Aschenbach, at 212-553-0880.

Sincerely,

Maria Matesanz

MM: DA: csf
cc:

Moody's Investors Service

Global Credit Research
New Issue
8 MAR 2006
Save as PDF

New Issue: Florida Municipal Power Agency

MOODY'S ASSIGNS A1 TO FLORIDA MUNICIPAL POWER AGENCY'S REVENUE BONDS

$452 MILLION ALL-REQUIREMENTS PROJECT REVENUE BOND SALE SCHEDULED

Electric Utilities
FL

Moody's Rating

ISSUE	RATING
Series 2006 A, B and C	A1
Sale Amount	$452,000,000
Expected Sale Date	03/13/06
Rating Description	All-Requirements Power Supply Project Revenue Bonds, Series 2006 A,B,C

Opinion

NEW YORK, Mar 8, 2006 -- Moody's Investors Service has assigned the underlying credit rating of A1 to the $452 million of Florida Municipal Power Agency (FMPA) All-Requirements Power Supply Project Revenue Bonds, Series 2006 A, B and C. The bonds are expected to be sold in mid-March 2006. The rating reflects the credit strength of each of the project's participants, the competitive price of the wholesale power contracts, the strong legal provisions backing the agency and its bonds and the project's operating and financial performance record. The bonds will be insured by a leading municipal bond insurance company. Upon review of the appropriate documentation, the bonds will be rated Aaa based on the financial strength credit rating of the municipal bond insurance company. Moody's will continue to maintain the underlying rating of A1 on the bonds.

Moody's has also affirmed the A1 rating on the outstanding $233,310,000 All-Requirements Project Revenue Bonds; the A1 on outstanding Stanton Project Revenue Bonds; A1 on the Tri-Cities Project Revenue Bonds; A1 on the Stanton II Project Revenue Bonds; and A2 on the St. Lucie Project Revenue Bonds.

FMPA has a well-established role managing relations between and among members, to whom it continues to provide important services, including activities to strengthen transmission system capability and resource adequacy. It has embarked on a plan to construct new generation facilities to meet future demand growth and diversify fuel mix. FMPA's financial position remains sound. Financial results have been pressured by the rise in fuel costs but cost recovery through a pass through mechanism continues to ensure satisfactory project liquidity.

USE OF BOND PROCEEDS: The current offering will finance the acquisition and construction of the Treasure Coast Energy Center, a 300 megawatt (MW)combined cycle unit natural gas fired power plant. The unit, to be located in Fort Pierce, is expected to begin operation in 2008. FMPA will also be financing its Public Gas Partner's Pool obligation for purchase of natural gas; pay termination costs of certain interest rate swap agreements; and partially refinance certain project loans of the All-Requirement Project.

LEGAL SECURITY: The All-Requirement bonds are secured by full requirements (subject to excluded resources) power supply agreements with an initial term to October 1, 2030, and which automatically renews each year for an additional year, subject to notification which can limit this automatic extension. On September 11, 2003, FMPA participants,Starke and Glen Cove Spring, notified FMPA of their decision not to renew their All-Requirements contracts and accordingly their contract will terminate October 1, 2036 and 2037 respectively. All-Requirements power sales contracts are joint and several obligations with no step-up

limitations. Upon at least five years notice, participants in the All-Requirements Project, may limit the maximum amount of electric capacity and energy they take. Vero Beach recently exercised this option and expects to become a partial requirements participant,effective January 1, 2010. Participants can impose this limit so as not to exceed the contract rate of delivery, defined as the participants peak demand during the 12 months preceding the one month prior to when the date the limitation commences, adjusted up or down by not more than 15% by FMPA. A participant can totally withdraw from the project upon a three year notice given on or before October 1 of each year. A participant that withdraws must pay in full its load ratio share of outstanding debt as well as any stranded costs. There is no debt service reserve for the current offering.

INTEREST RATE DERIVATIVES: FMPA utilizes interest rate swaps in managing its debt.. FMPA has a reasonable swap policy accepted by its board; has clear authorization to enter into swaps; and includes an assessment detailing risk exposures and policy oversight in its financial statements.

For additional credit information on Florida Municipal Power Agency, please refer to Moody's High Profile Rating Update report dated August 2005.

Strengths:

*Strong power purchase contracts with project participants.

*Active and strong interlocal service role including strengthening transmission capability and power resource adequacy.

*Each project including the All-Requirements has had a sound financial and operating performance record.

*Risk management program has mitigated fuel and interest rate risk and the monthly fuel cost pass-through has maintained liquidity.

*License extension, FMPA debt management and the reliability exchange are positive considerations related to St. Lucie Nuclear Unit ownership.

*Diverse fuel mix and multiple generating units.

Challenges:

*Construction risks related to FMPA's plan to construct a 300MW natural gas fired unit.

*Exposure to persistently high natural gas and rising coal prices.

*Many FMPA member electric utilities have sizable transfers of electric fund revenues to their city General Funds which is a factor in above average retail rates.

MARKET POSITION/COMPETITIVE STRATEGY: WHOLESALE RATE COMPETITIVENESS UNDER PRESSURE

FMPA represents the majority of the 33 public power utilities that serve electricity customers in the state. The All-Requirements Project has 15 municipal utility participants. Five cities (Jacksonville Beach, Ocala, Kissimmee Utilities Authority, Vero Beach and Key West) represent 72% of the All-Requirements Project. The average rating of FMPA participants is in the A1 to A2 range. An important credit strength is that municipal electric utilities are governed by their local city councils and rates are locally established and not regulated by the state public service commission, except for rate class structures among and between customer classes.

The electric industry in Florida however is dominated by the two major investor-owned utilities: Florida Power & Light (senior secured bonds rated Aa3 by Moody's) and Progress Energy-Florida (senior secured bonds rated A2).

Florida's electric industry is characterized by limited industrial concentration, a high residential demand growth rate and a constructive regulatory environment. There are transmission constraints affecting the amount of energy that can be transported into Florida which places significant weight on intrastate

transmission and local area generation projects. About 35% of electricity in Florida is derived from natural-gas fired generation. While the state has an adequate reserve margin, there is limited transmission and generation capacity to meet future electricity sales growth. Environmental restrictions on air quality and water supply are potential future pressures. There have been limited deregulation activities in the state including no significant movement towards formation of a regional transmission organization.

Most of the FMPA participant municipal electric utilities currently have residential retail rates that are above or at the average Florida rate for the major investor-owned utilities. The major factors behind why municipal electric utility electricity rates are higher than average include a significant General Fund transfer requirement and rising natural gas prices. FMPA project costs are competitive against average benchmarks for coal and nuclear generation.

Continued high natural gas and coal prices and disruption in coal deliveries has challenged most Florida electric utilities, including FMPA. While the agency has limited the extent of the impact of commodity price increases due to its somewhat diverse fuel mix (25% coal; 40% natural gas, 10% nuclear and 25% purchased power), the persistence of high prices has had an impact on power rates. FMPA has mitigated some of the price volatility with its active risk management activities including an active natural gas price hedging program. FMPA has also entered into contracts for firm gas supply at discounted index prices and helped form a new joint action agency, Public Gas Partners, to implement long-term wholesale fuel acquisition to further stabilize costs.

FMPA has established a well-defined risk management plan that focuses on balancing risk exposure and costs across the entire FMPA organization. The basis of the risk management policy is to compare the range of possible outcomes and probabilities of decisions that are proposed to be made. The policy addresses energy, debt, investment, insurance, credit and contract risk. FMPA management has made this a priority and has established functional oversight and risk policy committees.

FINANCIAL POSITION AND PERFORMANCE; PRESSURED BY RISE IN NATURAL GAS PRICES BUT FMPA CONTINUES TO RECOVER ITS COSTS AND MAINTAIN LIQUIDITY

FMPA maintains a sound financial condition with rates for power billings to FMPA participants designed to provide for full recovery of project costs over the life of the projects. Rising commodity prices continued to affect financial operations in fiscal year 2005. Financial results were also impacted by the scheduled outages at St. Lucie and Stanton.

FMPA has the authority to pass through fuel cost increases in rates. FMPA billing rates are not regulated by the state regulatory board and can be raised by 8% by FMPA management for the All-Requirements project, subject to subsequent affirmation by the All-Requirements Project participants.

A new rate process has been implemented which is geared towards meeting liquidity targets based on certain risk tolerance levels. The mechanism is automatic and implemented monthly. Each project has satisfactory debt service coverage ratios. Net working capital, as defined by Moody's calculations, shows that each project maintains satisfactory liquidity.

FMPA's consolidated debt ratio was 110% in 2005 compared to national median of 124.4%.

FMPA utilizes swaps particularly in managing the St. Lucie Project debt converting variable interest rate debt to fixed rates. FMPA has a detailed swap policy assessment in its financial statements which details risk exposure and policy oversight.

CAPITAL PROGRAM:FMPA BEGINS A MAJOR POWER RESOURCE PLAN TO MEET FUTURE GROWTH IN MEMBER DEMAND

FMPA focused on identifying new power resources to meet future demand growth for its All-Requirements members. This is an example of its joint action agency role that we consider a credit strength. In 2004, the agency conducted an integrated resource review which assessed the most economic power resource options that fit FMPA objectives of fuel diversification and meeting new electrical demand.

FMPA has proceeded with the financing of the 300 MW natural gas-fired generation unit at the Treasure Coast Energy Center located in the City of Fort Pierce. The advantages of the site include its location near several FMPA member cities that are experiencing growth. The local area generation also avoids congestion issues with the state's transmission grid. FMPA will be able to replace expiring purchase power contracts and also displace several older less-efficient generation units.

FMPA is also a major participant in the development process for a proposed 800 MW North Florida Power Project, which is a $1.4 billion coal-fired generation facility. FMPA is partnering on the project with JEA (rated Aa2 by Moody's) and Reedy Creek Improvement District (rated A3) and the City of Tallahassee (electric revenue bonds rated A1). FMPA expects to take 300 MW of the generation unit's output. Preliminary schedule includes a 2012 commercial date. The development of the project is subject to site selection and securing the necessary regulatory permits.

Outlook

Moody's maintains a stable outlook on all FMPA project revenue bonds. The outlook on the All-Requirements revenue bonds is stable given FMPA's sound risk management program; strength of power supply contracts and the important interlocal role the agency plays.

What Could Change the Rating-UP:

The rating could be raised with a stronger liquidity position and further moderation of cost of power.

What Could Change the Rating-DOWN:

Failure to meet the contractual obligation by a FMPA member could change the rating down. Persistent high natural gas prices could impact willingness to raise rates by FMPA All-Requirements customers which may pressure contract compliance and result in a downgrade.

KEY INDICATORS:

Major Participants and % of All-Requirements Project:

Jacksonville Beach, Key West, Kissimmee Utilities Authority, Ocala,

And Vero Beach: 72%

Cost of Power (cents/kwh), 2005:

All-Requirements: 6.35

St. Lucie Nuclear Project: 6.05

Stanton Coal-Fired Project: 4.45

St. Lucie Nuclear Unit 1,2, 2002-2004 Capacity Factor: 94%

Stanton Coal-Fired Generation Facility, 2004 Availability Factor,

Unit 1: 90.4%

Unit 2: 87.4%

FMPA Fuel Mix, 2005:

Coal: 25%

Natural Gas: 40%

Nuclear: 10%

Purchased Power: 25%

Debt Statement as of March 31, 2006 ($000)

Underlying Rating Amount Outstanding ($000)

St. Lucie Project Revenue Bonds (rated A2) $262,000

Stanton Project Revenue Bonds (A1) 81,237

All-Requirements Project-Various series (A1) 233,310 (1)

Tri-Cities Project Revenue Bonds (A1) 35,774

Stanton II Project Revenue Bonds (A1) 194,424

(1) Excluding pooled loans and current offering

ISSUER CONTACT:

Roger A. Fontes, General Manager 407-355-7767

Analysts

Dan Aschenbach
Analyst
Public Finance Group
Moody's Investors Service

Joshua Schaff
Backup Analyst
Public Finance Group
Moody's Investors Service

John Incorvaia
Senior Credit Officer
Public Finance Group
Moody's Investors Service

Contacts

Journalists: (212) 553-0376
Research Clients: (212) 553-1653

© Copyright 2006, Moody's Investors Service, Inc. and/or its licensors including Moody's Assurance Company, Inc. (together, "MOODY'S"). All rights reserved.

ALL INFORMATION CONTAINED HEREIN IS PROTECTED BY COPYRIGHT LAW AND NONE OF SUCH INFORMATION MAY BE COPIED OR OTHERWISE REPRODUCED, REPACKAGED, FURTHER TRANSMITTED, TRANSFERRED, DISSEMINATED, REDISTRIBUTED OR RESOLD, OR STORED FOR SUBSEQUENT USE FOR ANY SUCH PURPOSE, IN WHOLE OR IN PART, IN ANY FORM OR MANNER OR BY ANY MEANS WHATSOEVER, BY ANY PERSON WITHOUT MOODY'S PRIOR WRITTEN CONSENT. All information contained herein is obtained by MOODY'S from sources believed by it to be accurate and reliable. Because of the possibility of human or mechanical error as well as other factors, however, such information is provided "as is" without warranty of any kind and MOODY'S, in particular, makes no representation or warranty, express or implied, as to the accuracy, timeliness, completeness, merchantability or fitness for any particular purpose of any such information. Under no circumstances shall MOODY'S have any liability to any person or entity for (a) any loss or damage in whole or in part caused by, resulting from, or relating to, any error (negligent or otherwise) or other circumstance or contingency within or outside the control of MOODY'S or any of its directors, officers, employees or agents in connection with the procurement, collection, compilation, analysis, interpretation, communication, publication or delivery of any such information, or (b) any direct, indirect, special, consequential, compensatory or incidental damages whatsoever (including without limitation, lost profits), even if MOODY'S is advised in advance of the possibility of such damages, resulting from the use of or inability to use, any such information. The credit ratings and financial reporting analysis observations, if any, constituting part of the information contained herein are, and must be construed solely as, statements of opinion and not statements of fact or recommendations to purchase, sell or hold any securities. NO WARRANTY, EXPRESS OR IMPLIED, AS TO THE ACCURACY, TIMELINESS, COMPLETENESS, MERCHANTABILITY OR FITNESS FOR ANY PARTICULAR PURPOSE OF ANY SUCH RATING OR OTHER OPINION OR INFORMATION IS GIVEN OR MADE BY MOODY'S IN ANY FORM OR MANNER WHATSOEVER. Each rating or other opinion must be weighed solely as one factor in any investment decision made by or on behalf of any user of the information contained herein, and each such user must accordingly

make its own study and evaluation of each security and of each issuer and guarantor of, and each provider of credit support for, each security that it may consider purchasing, holding or selling.

MOODY'S hereby discloses that most issuers of debt securities (including corporate and municipal bonds, debentures, notes and commercial paper) and preferred stock rated by MOODY'S have, prior to assignment of any rating, agreed to pay to MOODY'S for appraisal and rating services rendered by it fees ranging from $1,500 to $2,400,000. Moody's Corporation (MCO) and its wholly-owned credit rating agency subsidiary, Moody's Investors Service (MIS), also maintain policies and procedures to address the independence of MIS's ratings and rating processes. Information regarding certain affiliations that may exist between directors of MCO and rated entities, and between entities who hold ratings from MIS and have also publicly reported to the SEC an ownership interest in MCO of more than 5%, is posted annually on Moody's website at www.moodys.com under the heading "Shareholder Relations - Corporate Governance - Director and Shareholder Affiliation Policy."

Moody's Investors Service Pty Limited does not hold an Australian financial services licence under the Corporations Act. This credit rating opinion has been prepared without taking into account any of your objectives, financial situation or needs. You should, before acting on the opinion, consider the appropriateness of the opinion having regard to your own objectives, financial situation and needs.

FitchRatings

One State Street Plaza
New York, NY 10004

T 212 908 0500 / 800 75 FITCH
www.fitchratings.com

March 8, 2006

Mr. Mark J. Larson
Chief Financial Officer
Florida Municipal Power Agency
8553 Commodity Circle
Orlando, FL 32819-9002

Dear Mr. Larson:

Fitch Ratings has assigned one or more ratings and/or otherwise taken rating action(s), as detailed on the attached Notice of Rating Action.

Ratings assigned by Fitch are based on documents and information provided to us by issuers, obligors, and/or their experts and agents, and are subject to receipt of the final closing documents. Fitch does not audit or verify the truth or accuracy of such information.

It is important that Fitch be provided with all information that may be material to its ratings so that they continue to accurately reflect the status of the rated issues. Ratings may be changed, withdrawn, suspended or placed on Rating Watch due to changes in, additions to or the inadequacy of information.

Ratings are not recommendations to buy, sell or hold securities. Ratings do not comment on the adequacy of market price, the suitability of any security for a particular investor, or the tax-exempt nature or taxability of payments made in respect of any security.

The assignment of a rating by Fitch shall not constitute a consent by Fitch to use its name as an expert in connection with any registration statement or other filing under U.S., U.K., or any other relevant securities laws.

We are pleased to have had the opportunity to be of service to you. If we can be of further assistance, please feel free to contact us at any time.

Sincerely,

Karl H. Pfe
Managing Director
Global Power

KHP/ka

Enc: Notice of Rating Action
(Doc ID: 30766)

Notice of Rating Action

Bond Description	Rating Type	Action	Rating	Outlook/ Watch	Eff Date	Notes
Florida Municipal Power Agency (FL) (All-Requirements Power Supply Project) auction-rate bonds ser 2006B	Long Term	New Rating	A+	RO:Sta	07-Mar-2006	
Florida Municipal Power Agency (FL) (All-Requirements Power Supply Project) auction-rate bonds ser 2006C	Long Term	New Rating	A+	RO:Sta	07-Mar-2006	
Florida Municipal Power Agency (FL) (All-Requirements Power Supply Project) rev bonds ser 2006A	Long Term	New Rating	A+	RO:Sta	07-Mar-2006	
Florida Municipal Power Agency (FL) (All-Requirements Power Supply Project) auction-rate bonds ser 2003 B-1 (insured: Financial Security Assurance Inc.)	Long Term	Affirmed	A+	RO:Sta	07-Mar-2006	1
Florida Municipal Power Agency (FL) (All-Requirements Power Supply Project) auction-rate bonds ser 2003 B-2 (insured: Financial Security Assurance Inc.)	Long Term	Affirmed	A+	RO:Sta	07-Mar-2006	1
Florida Municipal Power Agency (FL) (All-Requirements Power Supply Project) rev bonds	Long Term	Affirmed	A+	RO:Sta	07-Mar-2006	
Florida Municipal Power Agency (FL) (All-Requirements Power Supply Project) rfdg rev bonds ser 2003 (insured: Financial Security Assurance Inc.)	Long Term	Affirmed	A+	RO:Sta	07-Mar-2006	1
Florida Municipal Power Agency (FL) (Stanton II Project) rfdg rev bonds (auction-rate securities) ser 2004 (insured: Financial Guaranty Insurance Company)	Long Term	Affirmed	A+	RO:Sta	07-Mar-2006	1
Florida Municipal Power Agency (FL) (Stanton II Project) rfdg rev bonds ser 2002 (insured: Ambac Assurance Corp.)	Long Term	Affirmed	A+	RO:Sta	07-Mar-2006	1
Florida Municipal Power Agency (FL) (Stanton II Project) rfdg rev bonds ser 2003A (insured: Financial Security Assurance Inc.)	Long Term	Affirmed	A+	RO:Sta	07-Mar-2006	1
Florida Municipal Power Agency (FL) (Stanton II Project) sr rev bonds	Long Term	Affirmed	A+	RO:Sta	07-Mar-2006	
Florida Municipal Power Agency (FL) (Stanton II Project) var-rate demand sub rev bonds	Long Term	Affirmed	A+	RO:Sta	07-Mar-2006	
Florida Municipal Power Agency (FL) (Stanton Project) auction-rate bonds ser 2003 (insured: Financial Security Assurance Inc.)	Long Term	Affirmed	A+	RO:Sta	07-Mar-2006	1
Florida Municipal Power Agency (FL) (Stanton Project) rev bonds (insured: MBIA Insurance Corp.)	Long Term	Affirmed	A+	RO:Sta	07-Mar-2006	1
Florida Municipal Power Agency (FL) (Stanton Project) rfdg rev bonds ser 2002 (insured: Financial Security Assurance Inc.)	Long Term	Affirmed	A+	RO:Sta	07-Mar-2006	1
Florida Municipal Power Agency (FL) (Stanton Project) var-rate demand rfdg rev bonds ser 1997 (insured: MBIA Insurance Corp.) (liquidity facility: Wachovia Bank, N. A.)	Long Term	Affirmed	A+	RO:Sta	07-Mar-2006	1
Florida Municipal Power Agency (FL) (Tri-City Project) rfdg rev bonds ser 2003A (insured: Financial Security Assurance Inc.)	Long Term	Affirmed	A+	RO:Sta	07-Mar-2006	1
Florida Municipal Power Agency (FL) (Tri-City Project) sr bonds	Long Term	Affirmed	A+	RO:Sta	07-Mar-2006	

Notice of Rating Action

Bond Description	Rating Type	Action	Rating	Outlook/ Watch	Eff Date	Notes
Florida Municipal Power Agency (FL) (St. Lucie Project) rfdg rev bonds ser 2002	Long Term	Upgrade	A	RO:Sta	07-Mar-2006	
Florida Municipal Power Agency (FL) (St. Lucie Project) rfdg rev bonds ser 2002-1 (insured: Ambac Assurance Corp.)	Long Term	Upgrade	A	RO:Sta	07-Mar-2006	1
Florida Municipal Power Agency (FL) (St. Lucie Project) rfdg rev bonds ser 2002-2 (insured: Ambac Assurance Corp.)	Long Term	Upgrade	A	RO:Sta	07-Mar-2006	1
Florida Municipal Power Agency (FL) (St. Lucie Project) rfdg rev bonds ser 2002-3 (insured: Ambac Assurance Corp.)	Long Term	Upgrade	A	RO:Sta	07-Mar-2006	1
Florida Municipal Power Agency (FL) (St. Lucie Project) sub rfdg rev bonds ser 2000 (insured: Ambac Assurance Corp.)	Long Term	Upgrade	A	RO:Sta	07-Mar-2006	1

Key: RO: Rating Outlook, RW: Rating Watch; Pos: Positive, Neg: Negative, Sta: Stable, Evo: Evolving

Notes

1 The rating is an underlying rating, given without consideration of credit enhancement.

HEARING EXHIBIT - 00000551

9

FMPA's Response to Staff's Fifth Request for Production of Documents (No. 16)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition to determine need for Cane Island Power Park Unit 4 electrical power plant in Osceola County, by Florida Municipal Power Agency.	DOCKET NO. 080253-EM DATED: July 21, 2008

FLORIDA MUNICIPAL POWER AGENCY RESPONSES TO STAFF'S FIFTH REQUEST FOR PRODUCTION DOCUMENTS (NO. 16)

Florida Municipal Power Agency (FMPA) pursuant to Rule 28-106.26, Florida Administrative Code, and Rule 1.350, Florida Rules of Civil Procedure, hereby responds to Staff's Fifth Request for Production of Documents (No. 16).

DOCUMENT REQUEST & RESPONSE

16. **On page 12, lines 8-12, of the direct testimony of Witness Reedy, he states that Gulfstream has indicated that it will be able to supply the natural gas needed by Cane Island Unit 4. Please provide copies of all documents indicating Gulfstream's assurance that it will be able to supply the natural gas needed by Cane Island Unit 4, as discussed.**

Response to POD 16

Gulfstream held a non-binding Open Season the fall of 2007 soliciting interested parties to participate in a proposed expansion of their pipeline system. FMPA submitted an expression of interest for 20,000 Dth/d of incremental capacity during this period. Attached is FMPA's *Non-binding Nomination Form for Gulfstream Mainline Expansion Open Season,* submitted August 24, 2007. Also attached is a memorandum titled "Firm Transportation Service to Cane Island" sent from Gulfstream to FMPA on January 17, 2008. The memorandum outlines the projected firm natural gas transportation service to Cane Island 4 as a result of FMPA's response to Gulfstream's non-binding Open Season.

Respectfully submitted this 21st day of July, 2008.

HOPPING GREEN & SAMS, P.A.

Gary V. Perko
Hopping Green & Sams, P.A.
123 S. Calhoun Street
Tallahassee, FL 32314
(850) 222-7500 (telephone)
(850) 224-8551 (facsimile)
Email: GPerko@hgslaw.com

Attorney for Florida Municipal Power Agency

Gulfstream Mainline Expansion Open Season

Non-binding Nomination Form

Shipper Information

Company FLORIDA MUNICIPAL POWER AGENCY

Contact BOB POLLACK & RICHARD MONTGOMERY

Title ENERGY RISK ANALYST

Address 8553 COMMODITY CIRCLE

Telephone 407-355-7767 Fax 407-355-5796

E-mail bob.pollack@fmpa.com & richard.montgomery@fmpa.com

Contract Requirements

Maximum Daily Transportation Quantity (dekatherms) 20,000 /DAY

Maximum Hourly Flow Rate (dekatherms) 1,250 /HOUR

Point(s) of Receipt ALL

Point(s) of Delivery CANE ISLAND - OSCEOLA (OTHERS TO BE DISCUSSED)

Service Commencement Date 2011

Contract Term (minimum 20 years) 20 YEARS

Signature of Requestor/Customer [signature] Date 8/29/07

Please send and/or fax the completed Nomination Form to:

Tina Olson
2701 Rocky Point Drive, Suite 1050
Tampa, Florida 33607
Phone: 813-288-1911
Fax 813-286-4438
tolson@spectraenergy.com

Contracting for Service

Upon completion of the Open Season and review of the facility requirements, all necessary documents will be transmitted to nominating parties. The definitive agreements will address required regulatory and management approvals and other applicable conditions necessary to proceed with development and construction of the project. All definitive transactions will be subject to the General Terms and Conditions of Gulfstream's FERC Gas Tariff.

Limitations and Reservations

Parties submitting nominations will be required to provide credit support, as determined by Gulfstream, for their obligations under any definitive agreement pursuant to this Open Season

These procedures and this brochure are informational, non-binding marketing documents. Neither the information contained herein nor the submission of a nomination form pursuant to this Open Season has or will establish a contractual relationship between Gulfstream and any party.

Clean Energy For Florida's Future

January 17, 2008

Mr. Richard Montgomery
Florida Municipal Power Agency
8553 Commodity Circle
Orlando, FL 32819-9002

RE: Firm Transportation Service to Cane Island

Dear Richard:

Gulfstream Natural Gas System, L.L.C. ("Gulfstream") hereby submits the following information in response to Florida Municipal Power Agency's ("FMPA") nomination in Gulfstream's G2 Expansion Project Open Season, for firm transportation service to FMPA's Cane Island Station. All terms below are for discussion purposes only and do not constitute an offer or create any binding agreement.

Gulfstream's service would be firm transportation service under Rate Schedule FTS with the following:

- Maximum Daily Quantity: 20,000 Dths
- Maximum Hourly Quantity: 1,200 Dths
- Minimum Delivery Pressure: 550 psig
- Primary Receipt Points: FMPA would have receipt point access to all receipt points in the Mobile, Alabama, or Pascagoula, Mississippi areas on a primary firm basis
- Primary Delivery Point: Cane Island
- Term of Service: Minimum Primary Term of 20 years
- Transportation Rate: The rate would be a negotiated rate mutually agreed upon by FMPA and Gulfstream and reflected in any final definitive agreements between FMPA and Gulfstream.

Any final definitive agreements arising out of these discussions are subject to approval by Gulfstream's management committee and the receipt of all necessary permits and all applicable regulatory approvals in form and substance acceptable to Gulfstream. Gulfstream looks forward to continuing these discussions and serving FMPA's firm transportation needs.

Sincerely,

George Matzke
Vice President, Marketing

Gulfstream Natural Gas System, L.L.C.
2701 North Rocky Point Drive · Suite 1050 · Tampa, FL 33607-654 · (813) 208 1611 · 813 289 4436 · www.gulfstreamgas.com

10

FMPA-1E, which consists of an errata sheet and revised tables for the Need for Power Application previously filed as FMPA-1

Cane Island Unit 4
Need for Power Application
Errata Sheet

Section 3.4
Page 3-9, add the following sentence at the end of the paragraph of text for Section 3.4 Unit Retirements:

Add "In addition to the planned retirements shown in Table 3-5, the Fort Pierce generating units were retired as follows:

1. Fort Pierce Unit 8 retired on January 24, 2008
2. Fort Pierce Unit 7, Combined Cycle, D1, and D2 retired on May 1, 2008

The total summer capacity of these retired units was 114 MW. Demolition of these units has begun."

Section 3.4
Table 3-5 "FMPA Planned Retirements" has been revised as follows to 1) remove the rows showing Fort Pierce Unit 7, Fort Pierce Unit 8, Fort Pierce Combined Cycle, and Fort Pierce D1 and 2 and 2) change the total retirements (bold item represents change):

Table 3-5
FMPA Planned Retirements

Unit Identification	Retirement Date	Summer Capacity Retired (MW)	Total Annual Summer Capacity Retired (MW)
Lake Worth Unit 3	5/1/2011	25	
Lake Worth Unit 5	5/1/2011	8	
Lake Worth GT 1	5/1/2011	27	
Lake Worth GT 2	5/1/2011	20	
Lake Worth D1-5	5/1/2011	10	89(1)
Hansel Combined Cycle	5/1/2012	47	47
Total Retirements			**136**

(1) Total Annual Summer Capacity Retired does not match sum of individual unit Summer Capacity Retired due to rounding.

Section 3.5

Table 3-6 "ARP's Existing and Approved/Planned Resource Capacity " has been revised as follows (bold items represent changes):

Table 3-6
ARP's Existing and Approved/Planned Resource Capacity[1]

Generating Resources	Summer Rating					
	2008	2009	2010	2011	2012	2013 - 2027
Excluded Resources (Nuclear)[2]	84	84	74	**74**	**84**	**84**
Stanton Coal Plant[3]	222	222	184	184	184	184
Stanton Combined Cycle Unit A[4]	45	45	45	45	45	45
Cane Island 1-3[4]	383	383	383	383	383	383
Indian River CTs	80	80	80	80	80	80
Stock Island 2-4	75	75	75	75	75	75
Key West Native Generation	41	41	41	41	41	41
Kissimmee Native Generation	47	47	47	47	0	0
Lake Worth Native Generation	89	89	89	0	0	0
Vero Beach Native Generation	138	138	0	0	0	0
TCEC	296	296	296	296	296	296
Total Generating Capacity[5]	1,500	1,500	1,314	**1,226**	**1,189**	**1,189**
Purchased Power						
PEF Partial Requirements	30	75	120	0	0	0
FPL Long-Term Partial Requirements	45	45	45	45	45	0
Calpine Purchase	100	100	0	0	0	0
Stanton A Purchase[6]	80	80	80	80	80	80
Southern Power Company Power Purchase Agreement	157	157	157	157	157	157
Total Purchased Power Resources[5]	412	457	402	282	282	237
Total Resources[5]	1,912	1,957	1,716	**1,508**	**1,470**	**1,426**

[1] Planned capacity prior to commercial operation of the Central Florida Power Project.
[2] Reduction in 2010 reflects the withdrawal of Vero Beach from the ARP. Increase in 2011 reflects planned upgrades.
[3] Reduction in 2010 reflects the withdrawal of Vero Beach from the ARP.
[4] Includes FMPA and KUA ownership capacity.
[5] Sums may not match FMPA totals due to rounding.
[6] Includes FMPA and KUA capacity purchased from Southern Company-Florida, LLC.

Section 3.8.1
Page 3-13 (bold text represents change).

Change
"FPUA operates an internal, looped 69 kV transmission system for system load and a 118 MW local power generating plant (shown in Table 3-5 with a retirement date of May 1, 2008)."

To
"FPUA operates an internal, looped 69 kV transmission system for system load and a 118 MW local power generating plant (**with retirement dates as shown in Section 3-4**)."

Section 20.2
Table 20-2 "CPWC Summaries for Scenario 1" has been revised as follows (bold items represent changes):

Table 20-2
CPWC Summaries for Scenario 1
($000)

Case	CPWC of Expansion Plan Including Cane Island 4 in 2011	CPWC of Expansion Plan Without Cane Island 4 in 2011	CPWC Savings for Expansion Plan with Cane Island 4 in 2011
Reference Case	$6,873,504	$6,909,247	**$35,743**
High Fuel	$7,521,022	$7,558,293	$37,271
Low Fuel	$6,215,140	$6,243,170	$28,030
High Load	$7,780,149	$7,801,735	$21,586
Low Load	$5,994,755	$6,076,238	$81,483
High Capital Cost	$6,984,600	$7,022,491	$37,891
Regulated CO_2	$7,708,642	**$7,744,841**	$36,200
High Fuel with Regulated CO_2	$8,556,917	$8,594,522	$37,605
High Regulated CO_2	$9,347,371	$9,387,259	$39,888

Section 20.2.4
Table 20-5 "CPWC Summaries for Scenario 4" has been revised as follows (bold items represent changes):

Table 20-5
CPWC Summaries for Scenario 4
($000)

Case	CPWC of Expansion Plan Including Cane Island 4 in 2011	CPWC of Expansion Plan Without Cane Island 4 in 2011	CPWC Savings for Expansion Plan with Cane Island 4 in 2011
Reference Case	$7,139,004	**$7,177,345**	$38,341
Regulated CO_2	$7,932,282	$7,972,993	$40,711

Section 7.7.2
Page 7-29, 5th bullet (bold text represents change).

Change "Low Discount--Assumes lower discount rate (4.0 percent) for allowance banking than S.280 Core (7.0 percent)"

To

"Low Discount--Assumes lower discount rate (4.0 percent) for allowance banking than S.280 Core (**8.0** percent)"

11

Errata sheet for the Pre-filed Direct Testimony of Thomas E. Reedy

HEARING EXHIBIT - 00000562

Pre-Filed Testimony, Reedy
Page 6, Lines 21-22

Change " owned by Fort Pierce Utilities Authority, Lake Worth, and "

To

" owned by Lake Worth and "

Pre-Filed Testimony, Reedy
Page 6, Line 23

Change " is 250 MW. "

To

" is **136** MW. **In addition to the planned retirements, the Fort Pierce generating units with a total summer capacity of 114 MW were retired during the first half of 2008 and demolition of these units has begun.**"

Pre-Filed Testimony, Reedy
Page 16, Line 17-18

Change "Yes. FMPA has requested NRIS from PEF and PEF approved NRIS for Cane Island 4 on March 31, 2008."

To

"No. NRIS was not requested under the Open Access Transmission Tariff (OATT). FMPA requested that Cane Island 4 be served as a new resource under the existing transmission service agreement with Progress Energy Florida (PEF), and PEF approved this request on March 31, 2008."

Pre-Filed Testimony, Reedy
Exhibit ___[TER-1], "ARP's Existing and Approved/Planned Resource Capacity" has been revised as follows (bold items represent changes):

ARP's Existing and Approved/Planned Resource Capacity[1]

Generating Resources	Summer Rating					
	2008	2009	2010	2011	2012	2013 - 2027
Excluded Resources (Nuclear)[2]	84	84	73	**74**	**84**	**84**
Stanton Coal Plant[3]	222	222	184	184	184	184
Stanton Combined Cycle Unit A[4]	45	45	45	45	45	45
Cane Island 1-3[4]	383	383	383	383	383	383
Indian River CTs	80	80	80	80	80	80
Stock Island 2-4	75	75	75	75	75	75
Key West Native Generation	41	41	41	41	41	41
Kissimmee Native Generation	47	47	47	47	0	0
Lake Worth Native Generation	89	89	89	0	0	0
Vero Beach Native Generation	138	138	0	0	0	0
Treasure Coast Energy Center	296	296	296	296	296	296
Total Generating Capacity[5]	1,500	1,500	1,314	**1,226**	**1,189**	**1,189**
Purchased Power						
PEF Partial Requirements	30	75	120	0	0	0
FPL Long-Term Partial Requirements	45	45	45	45	45	0
Calpine Purchase	100	100	0	0	0	0
Stanton A Purchase[6]	80	80	80	80	80	80
Southern Power Company Power Purchase Agreement	157	157	157	157	157	157
Total Purchased Power Resources[5]	412	457	402	282	282	237
Total Resources[5]	1,912	1,957	1,716	**1,508**	**1,470**	**1,426**

[1] Planned capacity prior to commercial operation of the Central Florida Power Project.
[2] Reduction in 2010 reflects the withdrawal of Vero Beach from ARP. Increase in 2011 reflects planned upgrades.
[3] Reduction in 2010 reflects the withdrawal of Vero Beach from ARP.
[4] Includes FMPA and KUA ownership capacity.
[5] Sums may not match FMPA totals due to rounding.
[6] Includes FMPA and KUA capacity purchased from Southern Company Florida, LLC.

12

Errata sheet for the Pre-filed Direct Testimony of Myron R. Rollins

Pre-Filed Testimony, Rollins
Page 8, Line 3-5.

Change "and a debt service reserve fund equal to 100 percent of the average annual debt service requirement"

To

"and **a 6 month debt service reserve fund.**"

13

Errata sheet for the Pre-filed Direct Testimony of Bradley E. Kushner

HEARING EXHIBIT - 00000567

Pre-Filed Testimony, Kushner

Exhibit __[BEK-5], Table 8 "CPWC Summaries for Scenario 4 – Renewables and DSM Expansion Scenario " has been revised as follows (bold items represent changes):

Table 8
CPWC Summaries for Scenario 4 – Renewables and DSM Expansion Scenario
($000)

Case	CPWC of Expansion Plan Including Cane Island 4 in 2011	CPWC of Expansion Plan Without Cane Island 4 in 2011	CPWC Savings for Expansion Plan with Cane Island 4 in 2011
Reference Case	$7,139,004	**$7,177,345**	$38,341
Regulated CO_2	$7,932,282	$7,972,993	$40,711

EXH. FMPA-1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080253-EM EXHIBIT 3
COMPANY FL Municipal Power Agency (Direct)
WITNESS All Witnesses (FMPA-1)
DATE 08-04-08

Hopping Green & Sams

Attorneys and Counselors
Writer's Direct Dial Number
(850) 425-2359

July 24, 2008

BY HAND DELIVERY

Ann Cole
Director, Office of the Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Docket No. 080253-EM

Dear Ms. Cole:

Enclosed for filing, on behalf of Florida Municipal Power Agency, are the original and fifteen copies of the following:

- Exhibit No. __ (FMPA-1E), which consists of an errata sheet and revised tables for the Need For Power Application previously filed as Exhibit No. __ (FMPA-1);
- An errata sheet for the Pre-filed Direct Testimony of Thomas E. Reedy;
- An errata sheet for the Pre-filed Direct Testimony of Myron R. Rollins; and
- An errata sheet for the Pre-filed Direct Testimony of Bradley E. Kushner.

Copies of the documents have been provided to the persons on the attached certificate of service.

Please stamp and return the enclosed extra copy of this filing. If you have any questions regarding this filing, please give me a call at 425-2359.

Very truly yours,

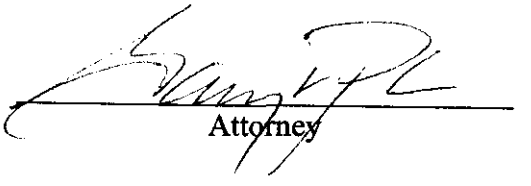
Gary V. Perko

Enclosures
cc: Certificate of Service

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing has been served by hand-delivery to the following parties on this 24th day of July, 2008:

Katherine Fleming
Senior Attorney
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, Florida 32399-0850



Attorney

Cane Island Unit 4
Need for Power Application
Errata Sheet

Section 3.4
Page 3-9, add the following sentence at the end of the paragraph of text for Section 3.4 Unit Retirements:

Add "In addition to the planned retirements shown in Table 3-5, the Fort Pierce generating units were retired as follows:

1. Fort Pierce Unit 8 retired on January 24, 2008
2. Fort Pierce Unit 7, Combined Cycle, D1, and D2 retired on May 1, 2008

The total summer capacity of these retired units was 114 MW. Demolition of these units has begun."

Section 3.4
Table 3-5 "FMPA Planned Retirements" has been revised as follows to 1) remove the rows showing Fort Pierce Unit 7, Fort Pierce Unit 8, Fort Pierce Combined Cycle, and Fort Pierce D1 and 2 and 2) change the total retirements (bold item represents change):

Table 3-5
FMPA Planned Retirements

Unit Identification	Retirement Date	Summer Capacity Retired (MW)	Total Annual Summer Capacity Retired (MW)
Lake Worth Unit 3	5/1/2011	25	
Lake Worth Unit 5	5/1/2011	8	
Lake Worth GT 1	5/1/2011	27	
Lake Worth GT 2	5/1/2011	20	
Lake Worth D1-5	5/1/2011	10	89(1)
Hansel Combined Cycle	5/1/2012	47	47
Total Retirements			**136**

(1) Total Annual Summer Capacity Retired does not match sum of individual unit Summer Capacity Retired due to rounding.

Section 3.5

Table 3-6 "ARP's Existing and Approved/Planned Resource Capacity " has been revised as follows (bold items represent changes):

Table 3-6
ARP's Existing and Approved/Planned Resource Capacity[1]

Generating Resources	Summer Rating					
	2008	2009	2010	2011	2012	2013 - 2027
Excluded Resources (Nuclear) [2]	84	84	74	**74**	**84**	**84**
Stanton Coal Plant[3]	222	222	184	184	184	184
Stanton Combined Cycle Unit A[4]	45	45	45	45	45	45
Cane Island 1-3[4]	383	383	383	383	383	383
Indian River CTs	80	80	80	80	80	80
Stock Island 2-4	75	75	75	75	75	75
Key West Native Generation	41	41	41	41	41	41
Kissimmee Native Generation	47	47	47	47	0	0
Lake Worth Native Generation	89	89	89	0	0	0
Vero Beach Native Generation	138	138	0	0	0	0
TCEC	296	296	296	296	296	296
Total Generating Capacity[5]	1,500	1,500	1,314	**1,226**	**1,189**	**1,189**
Purchased Power						
PEF Partial Requirements	30	75	120	0	0	0
FPL Long-Term Partial Requirements	45	45	45	45	45	0
Calpine Purchase	100	100	0	0	0	0
Stanton A Purchase[6]	80	80	80	80	80	80
Southern Power Company Power Purchase Agreement	157	157	157	157	157	157
Total Purchased Power Resources[5]	412	457	402	282	282	237
Total Resources[5]	1,912	1,957	1,716	**1,508**	**1,470**	**1,426**

[1] Planned capacity prior to commercial operation of the Central Florida Power Project.
[2] Reduction in 2010 reflects the withdrawal of Vero Beach from the ARP. Increase in 2011 reflects planned upgrades.
[3] Reduction in 2010 reflects the withdrawal of Vero Beach from the ARP.
[4] Includes FMPA and KUA ownership capacity.
[5] Sums may not match FMPA totals due to rounding.
[6] Includes FMPA and KUA capacity purchased from Southern Company-Florida, LLC.

Section 3.8.1
Page 3-13 (bold text represents change).

Change
"FPUA operates an internal, looped 69 kV transmission system for system load and a 118 MW local power generating plant (shown in Table 3-5 with a retirement date of May 1, 2008)."

To
"FPUA operates an internal, looped 69 kV transmission system for system load and a 118 MW local power generating plant **(with retirement dates as shown in Section 3-4)**."

Section 20.2
Table 20-2 "CPWC Summaries for Scenario 1" has been revised as follows (bold items represent changes):

Table 20-2
CPWC Summaries for Scenario 1
($000)

Case	CPWC of Expansion Plan Including Cane Island 4 in 2011	CPWC of Expansion Plan Without Cane Island 4 in 2011	CPWC Savings for Expansion Plan with Cane Island 4 in 2011
Reference Case	$6,873,504	$6,909,247	**$35,743**
High Fuel	$7,521,022	$7,558,293	$37,271
Low Fuel	$6,215,140	$6,243,170	$28,030
High Load	$7,780,149	$7,801,735	$21,586
Low Load	$5,994,755	$6,076,238	$81,483
High Capital Cost	$6,984,600	$7,022,491	$37,891
Regulated CO_2	$7,708,642	**$7,744,841**	$36,200
High Fuel with Regulated CO_2	$8,556,917	$8,594,522	$37,605
High Regulated CO_2	$9,347,371	$9,387,259	$39,888

Table of Contents

1.0 Executive Summary 1-1
1.1 The Applicant 1-1
1.2 The Proposed New Unit 1-1
1.3 The Power Plant Siting Act Process 1-1
1.4 The Commission's Need Determination 1-2
1.5 The Need for Cane Island Unit 4 1-2
1.6 Analysis of Generating ("Supply Side") Alternatives 1-3
1.7 Analysis of Non-Generating ("Demand Side") Alternatives 1-3
1.8 The ARP's Carbon Reduction Activities 1-3
1.9 Integrated Fuel and Emission Allowance Cost Projections 1-4
1.10 Most Cost Effective Alternative 1-4
1.11 Adverse Consequences If Cane Island Unit 4 Is Not Built 1-4
1.12 Conclusion 1-5

2.0 Introduction 2-1

3.0 Description of Existing System 3-1
3.1 FMPA Structure 3-1
3.1.1 Organization and Governance 3-1
3.1.2 ARP Members 3-2
3.1.3 ARP Member City Locations 3-4
3.1.4 FMPA Power Supply Projects 3-4
3.2 FMPA ARP Generation 3-8
3.2.1 FMPA ARP Solely Owned Generation 3-8
3.2.2 FMPA ARP Jointly Owned Generation 3-8
3.2.3 ARP Member Owned Generation 3-8
3.3 Purchase Power Contracts 3-9
3.4 Unit Retirements 3-9
3.5 Net ARP Capacity Resources 3-11

Table of Contents (Continued)

3.6 Florida Municipal Power Pool (FMPP) 3-12
3.7 Operating and Spinning Reserve Requirements 3-12
3.8 Transmission System 3-12
3.8.1 Member Transmission Systems 3-13
3.8.2 Transmission Agreements 3-15
3.9 Load and Electrical Characteristics 3-15
3.10 Description of Existing Renewable Projects 3-16
3.10.1 FMPA Renewable Projects 3-16
3.10.2 ARP Member Renewable Projects 3-16

4.0 Economic Parameters 4-1
4.1 Inflation and Escalation Rates 4-1
4.2 Municipal Bond Interest Rate 4-1
4.3 Present Worth Discount Rate 4-1
4.4 Interest During Construction Interest Rate 4-1
4.5 Levelized Fixed Charge Rate 4-1

5.0 Forecast of Electrical Demand and Consumption 5-1
5.1 Introduction 5-1
5.2 Load Forecast Process 5-1
5.3 Load Forecast Overview 5-2
5.4 Load Forecast Methodology 5-3
5.5 Model Specification 5-3
5.6 Projection of Net Energy for Load and Peak Demand 5-4
5.6.1 ARP Member NEL and Peak Demand 5-4
5.6.2 Transmission System Losses 5-5
5.7 Principal Considerations and Assumptions 5-5
5.7.1 Historical ARP Member Data 5-6
5.7.2 Weather Data 5-6
5.7.3 Economic Data 5-7
5.7.4 Real Electricity Price Data 5-8
5.8 Uncertainty of the Forecast 5-8

Table of Contents (Continued)

5.9 Overview of Results 5-10
5.9.1 Base Load Forecast 5-10
5.9.2 High and Low Load Forecasts 5-10
5.10 Price Elasticity of the Load Forecast 5-13

6.0 Natural Gas Availability 6-1
6.1 Natural Gas Production 6-1
6.1.1 Future Natural Gas Production 6-2
6.1.2 Natural Gas Production in the Lower 48 Outer Continental Shelf 6-3
6.2 Liquefied Natural Gas (LNG) 6-4
6.2.1 Liquefied Natural Gas in the North America 6-5
6.2.2 Existing LNG Importing Countries for North America 6-7
6.3 Natural Gas Reserves 6-12
6.3.1 Natural Gas Demand 6-13
6.4 Natural Gas Pipeline and Storage 6-15
6.4.1 Natural Gas Storage Facilities in Florida 6-15
6.5 Southeast Supply Header 6-20
6.5.1 Floridian Natural Gas Storage Company 6-20
6.6 Summary of Natural Gas Availability 6-21

7.0 Fuel and Emissions Allowance Price Projections 7-1
7.1 Importance of Fully Integrated Fuel and Emissions Allowance Price Projections 7-1
7.2 Description of 2007 US Energy Information Administration Annual Energy Outlook Reference Case 7-1
7.2.1 Consideration of State and Federal Legislation and Regulations in AEO2007 7-2
7.3 AEO2007 Reference Case FRCC Natural Gas, Fuel Oil, and Coal Price Projections 7-3
7.4 AEO2007 High and Low Price Case Natural Gas, Fuel Oil, and Coal Price Projections 7-6
7.5 FRCC High and Low Fuel Price Projections 7-17
7.5.1 High Fuel Price Projections for FRCC 7-17
7.5.2 Low Fuel Price Projections for the FRCC 7-19

Table of Contents (Continued)

7.6 US Energy Information Administration Annual Energy Outlook 2007 Emissions Allowance Price Projections 7-22
7.6.1 AEO2007 High Case Emissions Allowance Price Projections 7-24
7.6.2 AEO2007 Low Case Emissions Allowance Price Projections 7-24
7.7 EIA Analysis of Senate Bill 280 7-24
7.7.1 Overview of the Proposed Climate Stewardship and Innovation Act of 2007 (S.280) 7-27
7.7.2 EIA Analysis of S.280 – Overview and Summary of Results 7-28
7.8 Consideration of EIA Analysis of Senate Bill 280 7-41
7.8.1 S.280 Core Case Fuel Prices Delivered to the FRCC Region 7-43
7.8.2 Carbon Dioxide Emissions Allowance Prices 7-43

8.0 Natural Gas Transportation 8-1
8.1 Florida Gas Transmission 8-1
8.1.1 Existing FGT System 8-2
8.1.2 Market Area Pipeline Interconnections 8-3
8.1.3 Planned FGT System Expansions 8-3
8.1.4 Projected FGT Natural Gas Transportation Costs 8-4
8.2 Gulfstream 8-4
8.2.1 Existing Gulfstream System 8-5
8.2.2 Market Area Pipeline Interconnections 8-6
8.2.3 Planned Gulfstream System Expansions 8-6
8.2.4 Projected Gulfstream Natural Gas Transportation Costs 8-7
8.3 Cypress Pipeline 8-7
8.3.1 Planned Cypress Pipeline Expansions 8-8
8.4 Projected Availability of Natural Gas Transportation Capacity 8-8

9.0 Project Overview 9-1
9.1 Description of Project 9-1
9.1.1 Mode of Operation 9-1
9.1.2 Combustion Turbine Generator 9-1
9.1.3 Heat Recovery Steam Generator 9-1
9.1.4 Steam Turbine Generator 9-2

Table of Contents (Continued)

9.1.5 Cooling Tower 9-2
9.1.6 Air Quality Control 9-3
9.1.7 Control System 9-3
9.1.8 Water Use 9-3
9.1.9 Project Process Wastewaters 9-4
9.1.10 Storm Water Management 9-4
9.1.11 Transmission Interconnection 9-4
9.1.12 Site Design Conditions 9-4
9.1.13 Site Plan 9-5
9.1.14 Water Mass Balance 9-5
9.1.15 Overall One-Line Diagram 9-5
9.1.16 Cycling Design Features 9-5
9.1.17 Ammonia Systems 9-9
9.1.18 Capability for Future Expansion 9-9
9.1.19 Fuel Supply 9-9
9.2 Project Procurement and Implementation Plan 9-10
9.3 Capital Cost 9-11
9.4 Operating and Maintenance Cost 9-12
9.4.1 Fixed O&M Costs 9-12
9.4.2 Variable O&M 9-13
9.5 Heat Rate 9-13
9.6 Emissions 9-14
9.7 Availability 9-14
9.8 Schedule 9-14

10.0 Oil Backup Analysis 10-1
10.1 Historical Rationale Regarding Oil Backup 10-1
10.2 Federal Requirements 10-1
10.3 NERC Requirements 10-2
10.4 Florida Gas Supply 10-2
10.5 Disadvantages of Dual Firing 10-3
10.6 Fuel Oil Delivery Limitations 10-3
10.7 Existing FMPA Dual Fuel Capability 10-5
10.8 Cane Island Site 10-5
10.9 Conclusion 10-6

Table of Contents (Continued)

11.0 Transmission System Impacts 11-1
11.1 Description of Interconnection 11-1
11.2 System Impact Analysis 11-1
11.3 FRCC and PEF Approval 11-2

12.0 Reliability Criteria 12-1
12.1 Reserve Sharing Requirements 12-1
12.2 Reserve Margin Requirements 12-1
12.2.1 Traditional 12-1
12.3 LOLP 12-3
12.4 Reliability Criteria Summary 12-3

13.0 Capacity Requirements 13-1

14.0 Supply-Side Alternatives 14-1
14.1 Conventional and Emerging Technologies 14-1
14.1.1 Generating Alternatives Assumptions 14-3
14.1.2 Existing Sites 14-5
14.1.3 Simple Cycle Combustion Turbine Alternatives 14-6
14.1.4 GE 7FA 1x1 Combined Cycle 14-14
14.1.5 Capital Costs, O&M Costs, Schedule, and Maintenance Summary 14-14

15.0 Power Supply Request for Proposals 15-1
15.1 Overview of the Power Supply RFP 15-1
15.2 Results of the Power Supply RFP 15-3

16.0 Renewable Energy 16-1
16.1 Existing FMPA Renewable Energy Resources 16-1
16.2 FMPA RFP for Renewable Capacity and Energy 16-2
16.2.1 Summary of RFP Responses 16-4
16.2.2 Renewables RFP Response Evaluation Process 16-4
16.3 FMPA RFP for Solar PV Equipment or Power Purchase Agreements 16-6
16.4 Additional Renewable Energy Resources 16-7
16.4.1 Bio-Fuels 16-7
16.4.2 Landfill Gas 16-8

Table of Contents (Continued)

16.4.3 Plasma Arc Technology 16-8
16.4.4 Customer-Owned Renewable Resources 16-8

17.0 Conservation and Demand-Side Management 17-1
17.1 Existing ARP Member Conservation and DSM Programs 17-1
17.1.1 Energy Audit Programs 17-1
17.1.2 Energy Saving Tips 17-4
17.1.3 Appliance and Other Rebates 17-4
17.1.4 On-Line Energy Audits 17-4
17.1.5 Load Profiling for Commercial Customers 17-5
17.1.6 Fix-Up Programs 17-5
17.1.7 ENERGY STAR® Program 17-6
17.1.8 Compact Fluorescent Bulbs 17-6
17.1.9 ESCO Projects 17-6
17.1.10 City Wide Energy Conservation 17-6
17.1.11 LED Traffic Signals 17-7
17.1.12 Green Initiatives at FMPA Facilities 17-7
17.2 FMPA RFP for Demand-Side Management Resources 17-7
17.2.1 Summary of RFP Responses 17-9
17.2.2 DSM RFP Response Evaluation Process 17-10
17.3 Additional Conservation and DSM Initiatives 17-11
17.3.1 Publix Demand Response Program 17-11
17.3.2 Potential ARP-Funded Energy Conservation Program 17-12
17.3.3 Florida Municipal Energy Efficiency Coalition 17-12
17.3.4 Florida Energy Sustainability Consortium 17-12
17.3.5 Demonstration of Energy-Efficient Developments Programs 17-12

18.0 Carbon Reduction Activities 18-1
18.1 Introduction 18-1
18.2 The ARP's Carbon Footprint 18-1
18.2.1 Methodology 18-1
18.2.2 Final Adjustments 18-2
18.2.3 Emissions Totals 18-2

Table of Contents (Continued)

18.3 Historical Carbon Reduction Activities 18-3
18.3.1 Generation Efficiency 18-3
18.3.2 Demand Side Management 18-6
18.4 Future Planned and Potential Carbon Reduction Activities 18-7
18.4.1 Treasure Coast Energy Center 18-7
18.4.2 Cane Island Unit 4 18-7
18.4.3 Nuclear Uprates 18-7
18.4.4 Future Nuclear Ownership 18-8
18.4.5 System Loss Reduction 18-8
18.4.6 Potential Future Renewable Resources 18-8
18.4.7 Potential Future Conservation Programs 18-9
18.5 Conclusion 18-9

19.0 Evaluation Methodology 19-1
19.1 Expansion Planning Simulation 19-1
19.2 Fuel and Emission Allowance Price Forecasts 19-1
19.3 Firm Natural Gas Transportation Costs 19-2
19.4 New Nuclear Generating Units 19-2
19.5 DSM Costs 19-3
19.6 Cumulative Present Worth Cost Analysis 19-3

20.0 Economic Evaluation 20-1
20.1 Overview of Evaluation Scenarios 20-1
20.1.1 Scenario 1 – Conventional Expansion Scenario 20-1
20.1.2 Scenario 2 – Renewable Expansion Scenario 20-5
20.1.3 Scenario 3 – DSM Expansion Scenario 20-5
20.1.4 Scenario 4 – Renewables and DSM Expansion Scenario 20-6
20.2 Results of the Economic Evaluations 20-6
20.2.1 CPWC Results of Scenario 1 Evaluations 20-6
20.2.2 CPWC Results of Scenario 2 Evaluations 20-6
20.2.3 CPWC Results of Scenario 3 Evaluations 20-6
20.2.4 CPWC Results of Scenario 4 Evaluations 20-8
20.3 Conclusions 20-8

Table of Contents (Continued)

21.0 Consequences of Delay 21-1
21.1 Economic Consequences 21-1
21.2 Reliability Consequences 21-1

22.0 Financial Analysis 22-1

Appendix A Request for Power Supply Proposals
Appendix B Request for Proposals Renewable Capacity and Energy
Appendix C Request for Proposals for Solar Photovoltaic Equipment or Power Purchase Agreement
Appendix D Request for Proposals for Demand-Side Management Resources

Tables

Table 3-1 St. Lucie Project Participants 3-6
Table 3-2 Stanton Project Participants 3-6
Table 3-3 Tri-City Project Participants 3-7
Table 3-4 Stanton II Project Participants 3-7
Table 3-5 FMPA Planned Retirements 3-10
Table 3-6 ARP's Existing and Approved/Planned Resource Capacity 3-11
Table 5-1 Historical and Projected Growth (%) in Households and Personal Income 5-7
Table 5-2 Economic and Demographic Uncertainty 5-9
Table 5-3 Total ARP Demand and Energy Forecast Base Case 5-11
Table 5-4 Total ARP Demand and Energy Forecast High and Low Forecasts 5-12
Table 7-1 Annual Energy Outlook 2007 Reference Case Price Projections Forecast of Natural Gas and Fuel Oil Delivered to the Florida Reliability Coordinating Council Boundary 7-4
Table 7-2 Annual Energy Outlook 2007 Reference Case Price Projections Forecast of Low Sulfur Central Appalachian Coal Delivered to the Georgia/Florida Region 7-5
Table 7-3 Natural Gas, Fuel Oil, and Coal Price Projections AEO2007 High Price Case and AEO2007 Reference Case 7-7
Table 7-4 Natural Gas, Fuel Oil, and Coal Price Projections AEO2007 Low Price Case and AEO2007 Reference Case 7-12

Table of Contents (Continued)

Tables (Continued)

Table 7-5 Annual Energy Outlook 2007 High Case Price Projections Forecast of Natural Gas, Fuel Oil, and Central Appalachian Coal Delivered to the Florida Reliability Coordinating Council 7-18

Table 7-6 Annual Energy Outlook 2007 Low Case Price Projections Forecast of Natural Gas, Fuel Oil, and Central Appalachian Coal Delivered to the Florida Reliability Coordinating Council 7-20

Table 7-7 Annual Energy Outlook 2007 Reference Case Price Projections Forecast of Emissions Allowance Prices for CAIR-Regulated Emissions 7-23

Table 7-8 Annual Energy Outlook 2007 High Case Price Projections Forecast of Emissions Allowance Prices for CAIR-Regulated Emissions 7-25

Table 7-9 Annual Energy Outlook 2007 Low Case Price Projections Forecast of Emissions Allowance Prices for CAIR-Regulated Emissions 7-26

Table 7-10 Natural Gas Price Projections for AEO2007 Reference Case and EIA Analysis of S.280 (Delivered 2005 $/mcf – Electric Power Sector, Including Cost of CO_2 Allowances for S.280 Cases) 7-31

Table 7-11 Distillate Fuel Oil Price Projections for AEO2007 Reference Case and EIA Analysis of S.280 (Delivered 2005 Cents/ Gallon – Electric Power Sector, Including Cost of CO_2 Allowances for S.280 Cases) 7-32

Table 7-12 Residual Fuel Oil Price Projections for AEO2007 Reference Case and EIA Analysis of S.280 (Delivered 2005 Cents/ Gallon – Electric Power Sector, Including Cost of CO_2 Allowances for S.280 Cases) 7-33

Table 7-13 Coal Price Projections for AEO2007 Reference Case and EIA Analysis of S.280 (Delivered 2005 $/MBtu – Electric Power Sector, Including Cost of CO_2 Allowances for S.280 Cases) 7-34

Table 7-14 CO_2 Emission Allowance Price Projections from EIA Analysis of S.280 (2005 $/Metric Ton CO_2 Equivalent) 7-35

Table 7-15 S. 280 Core Case Natural Gas, Fuel Oil, and Coal Price Projections Compared to Non-Adjusted Fuel Price Forecasts (2005 $/MBtu) 7-42

Table 7-16 Forecast of Fuel Prices Delivered to FRCC Considering Potential Impact of S.280 (EIA S.280 Core Case) (2005 $/MBtu) 7-44

Table 7-17 Projected CO_2 Emission Allowance Prices EIA S.280 Core Case 7-45

Table of Contents (Continued)
Tables (Continued)

Table 9-1	Conceptual Design Conditions for the Project Site	9-5
Table 9-2	Indicative Hourly Fuel Consumption Rates	9-10
Table 9-3	Cane Island 4 In-Service Capital Cost Estimate ($000)	9-12
Table 9-4	Estimated 1x1 F Class Combined Cycle Performance (Natural Gas)	9-13
Table 9-5	Cane Island 4 Estimated Emissions	9-14
Table 10-1	Cost to Add Liquid Fuel Firing for Cane Island 4	10-4
Table 10-2	Fuel Oil Requirements	10-5
Table 13-1	Projected Reliability Levels – Summer – Base Case Load Forecast	13-2
Table 14-1	Possible Owner's Costs	14-2
Table 14-2	Nonrecoverable Degradation Factors	14-5
Table 14-3	GE LM6000 PC SPRINT Combustion Turbine Characteristics	14-8
Table 14-4	GE LM6000 PC SPRINT Estimated Emissions	14-8
Table 14-5	GE 7EA Combustion Turbine Characteristics	14-9
Table 14-6	GE 7EA Estimated Emissions	14-10
Table 14-7	GE 7FA Combustion Turbine Characteristics	14-11
Table 14-8	GE 7FA Estimated Emissions	14-11
Table 14-9	GE LMS100 Combustion Turbine Characteristics	14-13
Table 14-10	GE LMS100 Estimated Emissions	14-13
Table 14-11	Capital Costs, O&M Costs, and Schedules for the Generating Alternatives (All Costs in 2008 Dollars, Unless Otherwise Noted)	14-15
Table 16-1	Historical Renewable Energy Generation – Existing ARP Renewable Resources	16-1
Table 17-1	Existing ARP Member DSM Programs	17-2
Table 18-1	Summary of ARP CO_2 Emissions in 1990 and 2000	18-3
Table 18-2	Recent and Scheduled Retirements of Member-Owned Generating Resources	18-4
Table 20-1	Projected CO_2 Emission Allowance Prices EPA S.2191 Scenario and EIA S.280 Core (Nominal $/Ton)	20-4
Table 20-2	CPWC Summaries for Scenario 1 ($000)	20-7
Table 20-3	CPWC Summaries for Scenario 2 ($000)	20-7
Table 20-4	CPWC Summaries for Scenario 3 ($000)	20-8
Table 20-5	CPWC Summaries for Scenario 4 ($000)	20-8

Table of Contents (Continued)

Figures

Figure 3-1 ARP Member Cities 3-5
Figure 5-1 Load Forecast Process 5-1
Figure 6-1 Forecasted Natural Gas Production by Source 6-3
Figure 6-2 Technically Recoverable Undiscovered Gas in the Lower 48 OCS 6-4
Figure 6-3 Top LNG Exporters to the United States 6-6
Figure 6-4 Current U.S LNG Import Terminals 6-6
Figure 6-5 Existing & Proposed Gulf Cost LNG Projects 6-9
Figure 6-6 Cypress Pipeline 6-11
Figure 6-7 Replacement of Dry Natural Gas Productions by Reserve Additions 1996 - 2006 6-13
Figure 6-8 Dry Natural Gas Proved Reserves 6-14
Figure 6-9 Technically Recoverable U.S. Natural Gas Resources 6-14
Figure 6-10 Florida Pipeline Capacity 6-16
Figure 6-11 Underground Storage into Florida 6-16
Figure 6-12 Southern Pines Energy Center (Source: www.sgr-holdings.com) 6-18
Figure 6-13 MoBay Storage Hub 6-18
Figure 6-14 Bay Gas Storage Facility 6-19
Figure 6-15 Southeast Supply Header Route Pipeline 6-20
Figure 7-1 Comparison of Natural Gas Price Projections AEO2007 High Price Case and AEO2007 Reference Case 7-8
Figure 7-2 Comparison of Distillate Fuel Oil Price Projections AEO2007 High Price Case and AEO2007 Reference Case 7-9
Figure 7-3 Comparison of Residual Fuel Oil Price Projections AEO2007 High Price Case and AEO2007 Reference Case 7-10
Figure 7-4 Comparison of Coal Price Projections AEO2007 High Price Case and AEO2007 Reference Case 7-11
Figure 7-5 Comparison of Natural Gas Price Projections AEO2007 Low Price Case and AEO2007 Reference Case 7-13
Figure 7-6 Comparison of Distillate Fuel Oil Price Projections AEO2007 Low Price Case and AEO2007 Reference Case 7-14
Figure 7-7 Comparison of Residual Fuel Oil Price Projections AEO2007 Low Price Case and AEO2007 Reference Case 7-15
Figure 7-8 Comparison of Coal Price Projections AEO2007 Low Price Case and AEO2007 Reference Case 7-16
Figure 7-9 Natural Gas Price Projections for AEO2007 Reference Case and EIA Analysis of S.280 (Delivered 2005 $/mcf - Electric Power Sector, Including Cost of CO_2 Allowances for S.280 Cases) 7-36

Table of Contents (Continued)
Figures (Continued)

Figure 7-10 Distillate Fuel Oil Price Projections for AEO2007 Reference Case and EIA Analysis of S.280 (Delivered 2005 Cents/Gallon - Electric Power Sector, Including Cost of CO_2 Allowances for S.280 Cases) 7-37
Figure 7-11 Residual Fuel Oil Price Projections for AEO2007 Reference Case and EIA Analysis of S.280 (Delivered 2005 Cents/Gallon - Electric Power Sector, Including Cost of CO_2 Allowances for S.280 Cases) 7-38
Figure 7-12 Coal Price Projections for AEO2007 Reference Case and EIA Analysis of S.280 (Delivered 2005 $/MBtu - Electric Power Sector, Including Cost of CO_2 Allowances for S.280 Cases) 7-39
Figure 7-13 CO_2 Emissions Allowance Price Projections from EIA Analysis of S.280 (2005 $/Metric Ton CO_2 Equivalent) 7-40
Figure 8-1 FGT System 8-1
Figure 8-2 Gulfstream System 8-5
Figure 8-3 Cypress Pipeline 8-7
Figure 9-1 Conceptual Site Plan 9-6
Figure 9-2 Preliminary Water Mass Balance 9-7
Figure 9-3 Conceptual One-Line Diagram 9-8
Figure 9-4 Cane Island 4 Schedule 9-16

1.0 Executive Summary

Florida Municipal Power Agency (FMPA) submits this Need for Power Application in support of a proposed natural gas-fired "combined cycle" electric generating unit to be located at the existing Cane Island generating station in Osceola County, Florida. The analyses summarized below and discussed throughout this Application demonstrate that the new unit is needed to meet the growing electrical demands of FMPA's All-Requirements Power Supply Project (ARP). The proposed project also is an essential component of the ARP's Carbon Reduction Activities to address climate change issues.

1.1 The Applicant

FMPA is a joint action agency comprised of 30 municipal electric utilities. FMPA was created so that its members could cooperatively gain mutual advantage and meet present and projected electric energy requirements. As part of this empowerment, FMPA developed the ARP to secure an adequate, economical and reliable supply of electric capacity and energy to meet the wholesale power needs (above certain excluded resources) of the ARP member municipal utilities serving approximately 180,000 customers throughout Florida. ARP members purchase all their capacity and energy from the ARP. FMPA meets the ARP's needs through electricity generated by FMPA owned or co-owned facilities, as well as power purchases from generating ARP members (i.e., members with their own generating capacity and purchases) and other, non-ARP member utilities.

1.2 The Proposed New Unit

The new unit, to be known as Cane Island Unit 4, will be a high-efficiency, natural gas-fueled combined cycle unit, consisting of a combustion turbine and a heat recovery steam generator that will drive a steam turbine generator. The new unit will be capable of generating nominally 300 megawatts (MW), enough electricity to serve approximately 60,000 homes in Florida. All of the generation capacity from the unit will be committed to ARP members for retail sale to their customers.

1.3 The Power Plant Siting Act Process

The Florida Electrical Power Plant Siting Act (PPSA), Chapter 403, Part II, Florida Statutes, provides a "centrally coordinated, one-stop licensing process" for power plant projects. The PPSA provides a centralized process to ensure that all affected state

and local agencies review a project before the Siting Board, consisting of the Governor and Cabinet, takes final action on the site certification application. The Commission's need determination is a critical step in the PPSA certification process. Along with the reports submitted by the Florida Department of Environmental Protection (DEP) and other agencies, the Commission's need determination allows the Siting Board to balance "the increasing demand for electrical power plants with the broad interests of the public."

1.4 The Commission's Need Determination

Section 403.519(3), Florida Statutes, sets forth the following criteria which the Commission must consider in making need determinations:

- The need for electric system reliability and integrity.
- The need for adequate electricity at a reasonable cost.
- The need for fuel diversity and supply reliability.
- Whether the proposed plant is the most cost-effective alternative available.
- Whether renewable energy sources and technologies, as well as conservation measures, are utilized to the extent reasonably available.
- Whether there are conservation measures taken by or reasonably available to the applicant or its members which might mitigate the need for the proposed plant.

The Legislature did not assign the weight this Commission is to give each of these factors. Rule 25-22.081, Florida Administrative Code, sets forth specific information that each Need for Power Application must include to allow the Commission to address the statutory factors. The required information is summarized below and discussed in detail in throughout this Application.

1.5 The Need for Cane Island Unit 4

The ARP's capacity needs have been growing rapidly. As discussed in Section 13.0 of the Need for Power Application, in the summer of 2011, FMPA's reserve margin is projected to decrease to -1.3 percent, or 286 MW below the required capacity. An additional 363 MW is needed to maintain an 18 percent reserve margin by the summer season of 2012. Many of the ARP's capacity and power purchase contracts are expiring, or nearing the end of their lifetime. By providing capacity necessary to meet the ARP's growing needs, Cane Island Unit 4 will contribute to the reliability and integrity of the FMPA/ARP electric system.

1.6 Analysis of Generating ("Supply Side") Alternatives

As discussed in Section 14.0 of this Application, FMPA has evaluated several supply side technologies, either as alternatives to Cane Island Unit 4 or as capacity resource options for installation following the proposed unit. As part of that analysis, FMPA evaluated renewable technologies, conventional technologies, and emerging technologies. Based on the results of production cost modeling of multiple economic scenarios, FMPA identified a new nominal 300 MW combined cycle generating facility as the most cost-effective alternative to meet the ARP's need for additional capacity.

Although FMPA is not subject to the Commission's "Bid Rule," the agency issued a competitive request for proposals (RFP) for purchase power options, as well as separate RFPs for renewable and solar energy resources. Based on FMPA's evaluation, none of the responses to the RFPs were cost-effective as compared to the self-build alternative. However, as a result of the renewable RFP, FMPA is pursuing a potential purchase of 58 MW of renewable energy from a new biomass facility. The ARP is also investigating a new solar initiative designed to achieve 100 MW of solar power within the next 10 years by installing solar photovoltaic technology at ARP member sites throughout Florida.

1.7 Analysis of Non-Generating ("Demand Side") Alternatives

As a wholesale supplier of electric energy to the ARP, FMPA is not directly responsible for demand-side management (DSM) programs. However, FMPA assists its members in the implementation of DSM. ARP members offer a variety of conservation and DSM programs to their consumers. The impact of these existing conservation and DSM programs are reflected in the load forecast presented in Section 5.0 of this Application.

FMPA issued an RFP for DSM proposals and is negotiating with two vendors which have proposed to work with ARP members to implement load control measures designed to reduce peak load demand by up to 44 MW within the next 9 years.

1.8 The ARP's Carbon Reduction Activities

On July 13, 2007, Governor Crist signed Executive Order 07-127 directing DEP to adopt new regulations requiring electric utilities to reduce carbon dioxide (CO_2) emissions. As yet, the specific regulatory framework has not been developed because DEP has not yet proposed or adopted any specific rules. Nevertheless, in light of the Governor's directive, the ARP is pursuing Carbon Reduction Activities to meet the dual challenge of providing reliable, affordable electricity while reducing emissions. Cane Island Unit 4 is an important component of that plan. Because it will be one of the

highest efficiency plants in the state, Cane Island Unit 4 will displace less efficient units with higher CO_2 emission rates.

1.9 Integrated Fuel and Emission Allowance Cost Projections

The costs of meeting all existing environmental regulations have been included in all of the economic analyses presented in this application. This includes costs of pollution control technology and emission allowances. Because fuel and emission allowance costs are interrelated, fuel and emission allowance cost projections included in this application are fully integrated. That is, fuel price supply and demand were considered in tandem with potential allowance costs, along with numerous other market influences, to develop fully integrated fuel and emission allowance cost projections.

Emission allowance cost projections for sulfur dioxide and nitrogen oxides are included throughout this application whether for the reference case, high case or low case scenarios. In addition, although no CO_2 regulatory programs have been adopted as yet, in light of continuing discussion of potential CO_2 regulation, this Application presents additional economic analyses which incorporate the range of CO_2 cost estimates, and associated fuel forecasts, developed by the U.S. Department of Energy's Energy Information Agency. These analyses demonstrate that Cane Island Unit 4 is still FMPA's most cost-effective alternative even assuming a carbon-regulated environment.

1.10 Most Cost Effective Alternative

After extensive economic comparisons to other generating unit and nongeneration alternatives, Cane Island Unit 4 was determined to be the most cost effective alternative to meet FMPA's needs. Under the reference case, the expansion plan with Cane Island Unit 4 was $35.7 million lower in cumulative present worth costs (CPWC) than the plan without Cane Island Unit 4.

1.11 Adverse Consequences If Cane Island Unit 4 Is Not Built

Delaying Cane Island Unit 4 would result in reduced reliability and higher costs. If the proposed unit is delayed, FMPA's summer reserve margin will fall to -5.9 percent in 2012 which is well below FMPA's 18 percent reserve margin criterion and would not allow FMPA to meet firm load. If other capacity would be installed to retain FMPA's 18 percent summer reserve margin, cumulative present worth costs would increase by more than $37.5 million with a two year delay.

1.12 Conclusion

The proposed unit will ensure that the ARP has an adequate supply of power to serve its members' needs at a reasonable cost. The competitive RFPs, together with separate economic analyses presented in the Need for Power Application demonstrate Cane Island Unit 4 is the most cost-effective alternative to meet the ARP's power supply needs. The ARP already utilizes reasonably available DSM programs and renewable resources. Even with potential demand and energy reductions that could be achieved from additional conservation and renewable energy initiatives that FMPA is pursuing, Cane Island Unit 4 is the ARP's least cost alternative to reliably meet the ARP's power supply needs.

2.0 Introduction

This application demonstrates the Need for Cane Island Unit 4 under Section 403.519 F.S. Cane Island Unit 4 is a nominal 300 MW 1x1 7FA natural gas fired combined cycle generating unit to be constructed at the existing Cane Island Power Park (CIPP) site by the Florida Municipal Power Agency (FMPA) All-Requirements Power Supply Project (ARP). CIPP contains three existing units that are jointly owned by FMPA and Kissimmee Utility Authority (KUA). Unit 1 is a simple cycle combustion turbine, and Units 2 and 3 are combined cycles. Cane Island Unit 4 is scheduled for commercial operation on May 1, 2011.

Section 3.0 provides a description of FMPA and FMPA's existing facilities. FMPA is a joint action with the ARP that provides all power supply requirements for 15 municipally owned member utilities. FMPA's resources are a mix of FMPA-owned generating units (wholly and jointly), member-owned generating units, and purchase power.

Section 4.0 of this application provides the economic parameters and assumptions used throughout the application.

Section 5.0 presents FMPA load forecast, which indicates continued strong load growth that requires the addition of Cane Island Unit 4.

Cane Island Unit 4 will be fueled by natural gas. Section 6.0 demonstrates the availability of natural gas to provide a reliable fuel for Cane Island Unit 4 to maintain the integrity of FMPA's system.

Section 7.0 presents the fuel price projections used in the economic evaluations. The fuel price projections are based on the Department of Energy's (DOE's) Annual Energy Outlook (AEO) projections and include projections of sulfur dioxide (SO_2), nitrogen oxide (NO_x), and carbon dioxide (CO_2) emissions allowances.

Section 8.0 discusses the available natural gas transportation system to serve Cane Island Unit 4 and demonstrates that the natural gas transportation will be reliable.

Section 9.0 describes Cane Island Unit 4 and provides the detailed cost estimate, operating costs, and performance parameters for the unit. Section 9.0 demonstrates that Cane Island Unit 4 will be designed and constructed so that it will operate reliably and maintain the integrity of FMPA's system.

Cane Island Unit 4 will be fueled by natural gas supplied from two independent pipeline systems and will not use fuel oil as a back-up fuel. Section 10.0 demonstrates that Cane Island 4, without fuel oil backup, is the correct economic approach and will reliably maintain FMPA's system integrity.

Section 11.0 describes Cane Island Unit 4's impact on the transmission system and the evaluations conducted to demonstrate that its interconnection will not have an adverse impact on the transmission system. Both the Florida Regional Reliability Council (FRCC) and Progress Energy Florida have approved Cane Island Unit 4's interconnection to the transmission system.

Section 12.0 discusses the 18 percent summer reserve margin used by FMPA to determine the need for Cane Island Unit 4.

Section 13.0 demonstrates FMPA's need for additional capacity by applying the 18 percent reserve margin to FMPA's projected load growth and comparing the capacity requirements to FMPA's existing resources.

Section 14.0 describes the conventional and emerging generating unit alternatives that were compared to Cane Island Unit 4 and used in expansion plans to provide FMPA's capacity needs beyond those supplied by Cane Island Unit 4.

As a municipal utility, FMPA is not required to conduct a request for proposals (RFP) process. Nevertheless, in an effort to ensure that there were no lower cost or better alternatives than Cane Island Unit 4, FMPA conducted a purchase power RFP process, which is documented in Section 15.0.

In a further effort to identify lower cost or better alternatives to Cane Island Unit 4, FMPA conducted two additional RFP processes. One process was for renewable alternatives, and one process was for solar photovoltaic alternatives. As a result of these RFP processes, FMPA is continuing its efforts to obtain biomass and solar photovoltaic capacity. Section 16.0 describes these RFP processes and demonstrates that FMPA is utilizing available renewable energy sources and technologies to the extent reasonably possible.

Section 17.0 describes the RFP process and FMPA's ongoing efforts to negotiate one or more contracts for DSM resources. While FMPA will continue to evaluate additional conservation and DSM programs, the RFP indicates that currently no reasonable available conservation and DSM programs mitigate the need for Cane Island Unit 4.

Section 18.0 describes FMPA's actions to reduce CO_2 emissions. Section 18.0 demonstrates that with FMPA's existing and planned carbon reduction initiatives, FMPA can reduce CO_2 emissions to below 2000 levels by 2017.

Section 19.0 describes the methodology used to evaluate the cost effectiveness of Cane Island Unit 4.

Section 20.0 presents the economic analyses conducted that demonstrate that Cane Island Unit 4 is FMPA's least-cost alternative under a wide range of scenarios. Cane Island Unit 4 is FMPA's least-cost alternative, even with the addition of renewables and conservation.

Section 21.0 presents the cost and reliability impacts of delaying the installation of Cane Island Unit 4.

Section 22.0 demonstrates that FMPA can readily finance the addition of Cane Island Unit 4.

3.0 Description of Existing System

3.1 FMPA Structure

FMPA is a governmental wholesale power company composed of 30 municipal electric utilities. FMPA provides economies of scale in power generation and related services to support community-owned electric utilities. Of FMPA's 30 member municipal utilities, 15 are served by the All-Requirements Power Supply Project (ARP) to secure an adequate, economical, and reliable supply of electric capacity and energy to meet the entire wholesale electric needs (excluding certain excluded resources)[1] of the 15 ARP members.

3.1.1 Organization and Governance

FMPA was created on February 24, 1978, by the signing of the Interlocal Agreement among its original members. This agreement specifies the purposes and authority of FMPA. FMPA was formed under the provisions of Article VII, Section 10 of the Florida Constitution; the Joint Power Act, Chapter 361, Part II, Florida Statutes; and the Florida Interlocal Cooperation Act of 1969, Section 163.01, Florida Statutes.

The Florida Constitution and the Joint Power Act provide the authority for municipal electric utilities to join together for the joint financing, constructing, acquiring, managing, operating, utilizing, and owning of electric power plants. The Interlocal Cooperation Act authorizes municipal electric utilities to cooperate with each other on the basis of mutual advantage to provide services and facilities that benefit the members. Such advantages include allowing FMPA to acquire and build facilities with the benefits of scale to lower costs for members, to provide integrated and less costly operational expertise, to manage an integrated transmission system on behalf of members, and to prevent the unnecessary duplication of facilities.

Each city commission, utility commission, or authority that is a signatory to the Interlocal Agreement has the right to appoint one member to FMPA's Board of Directors, the governing body of FMPA. The Board has the responsibility for developing and approving FMPA's budget for power supply projects other than the ARP, approving and financing projects, hiring a General Manager and General Counsel, establishing bylaws that govern how FMPA operates, and creating policies that implement such bylaws. At its annual meeting, the Board elects a Chairman, Vice Chairman, Secretary, and Treasurer. The Executive Committee is composed of one representative from each of the 15 ARP participants. The Executive Committee has charge over the governance and

[1] Excluded resources are the ARP members' shares of the Crystal River Unit 3 and St. Lucie Unit 2 nuclear units.

management of the business of the ARP and approves the FMPA general budget, and all agency general budget amendments.

Municipal utilities are able to become members of the ARP if such membership is mutually beneficial to both the ARP and the municipal utility. Membership in the ARP is a contractually governed entitlement, and both the municipal utility and the ARP are required to fulfill obligations, specific to each member's All-Requirements Power Supply Project contract and its Capacity and Energy Sales Contract (C&E Contract) for members that own generation.

In general, ARP members are classified as either generating or non-generating members. All ARP members are required to purchase all of their capacity and energy from the ARP, with the exception of excluded resources that are generally the members' ownership share of Crystal River Unit 3 and St. Lucie Unit 2. Generating members are reimbursed in the form of credits for their capacity and energy contributions to the ARP. Once a municipal utility has joined the ARP, a contract is signed for a term of 30 years, and this contract is automatically renewed unless the member elects otherwise.

3.1.2 ARP Members

The 15 members of the ARP are identified below.

Bushnell

The City of Bushnell is located in central Florida in Sumter County. It joined the ARP in May 1986; its service area is 1.4 square miles.

Clewiston

The City of Clewiston is located in southern Florida in Hendry County. It joined the ARP in May 1991; its service area is approximately 5 square miles.

Fort Meade

The City of Fort Meade is located in central Florida in Polk County. It joined the ARP in February 2000; its service area is approximately 5 square miles. FMPA serves capacity and energy (C&E) requirements for the City of Fort Meade via the full requirements agreement currently in place with Tampa Electric Company (TECO). When the Fort Meade/TECO agreement terminates in January 2009, FMPA will serve the city from the ARP's portfolio of power supply resources.

Fort Pierce Utilities Authority

The City of Fort Pierce is located on Florida's east coast in St. Lucie County. Fort Pierce Utilities Authority (FPUA) joined the ARP in January 1998; its service area is approximately 35 square miles.

Green Cove Springs

The City of Green Cove Springs is located in northeast Florida in Clay County. It joined the ARP in May 1986; its service area is approximately 25 square miles.

Town of Havana

The Town of Havana is located in the panhandle of Florida in Gadsden County. It joined the ARP in July 2000; its service area is 4.5 square miles.

Jacksonville Beach

The City of Jacksonville Beach's electric department, more commonly known as Beaches Energy Services (Beaches), is located in northeast Florida in Duval County. Beaches joined the ARP in May 1986; its service area is approximately 45 square miles and includes portions of St. John's County.

Utility Board, City of Key West

The Utility Board of the City of Key West, also known as Keys Energy Services (KEYS), provides electric service to the lower Keys in Monroe County. KEYS joined the ARP in April 1998; its service area is approximately 45 square miles.

Kissimmee Utility Authority

Kissimmee is located in central Florida in Osceola County. The Kissimmee Utility Authority (KUA) joined the ARP in October 2002; its service area is approximately 85 square miles.

Lake Worth

Lake Worth is located on Florida's east coast in Palm Beach County. Lake Worth joined the ARP in October 2002; its service area is 12.5 square miles.

Leesburg

The City of Leesburg is located in central Florida in Lake County. It joined the ARP in May 1986; its service area is approximately 50 square miles.

Newberry

The City of Newberry is located in the northern part of Florida in Alachua County. It joined the ARP in December 2000; its service area is approximately 6 square miles.

Ocala

The City of Ocala is located in central Florida in Marion County. It joined the ARP in May 1986; its service area is approximately 161 square miles.

Starke

The City of Starke is located in north Florida in Bradford County. It joined the ARP in October 1997; its service area is 6.5 square miles.

Vero Beach

The City of Vero Beach is located on Florida's east coast in Indian River County. It joined the ARP in June 1997; its service area is approximately 40 square miles.

3.1.3 ARP Member City Locations

Figure 3-1 shows the ARP member city locations.

3.1.4 FMPA Power Supply Projects

In addition to the ARP, FMPA has four other power supply projects in operation: (i) the St. Lucie Project (ii) the Stanton Project, (iii) the Tri-City Project, and (iv) the Stanton II Project. These four projects are briefly discussed below.

St. Lucie Project

On May 12, 1983, FMPA purchased from Florida Power & Light (FPL) an 8.806 percent undivided ownership interest in St. Lucie Unit 2 (the St. Lucie Project), a nuclear generating unit. St. Lucie Unit 2 was declared in commercial operation on August 8, 1983, and in Firm Operation (as defined in the participation agreement) on August 14, 1983. Fifteen of FMPA's members are participants in the St. Lucie Project, with the following entitlements as shown in Table 3-1.

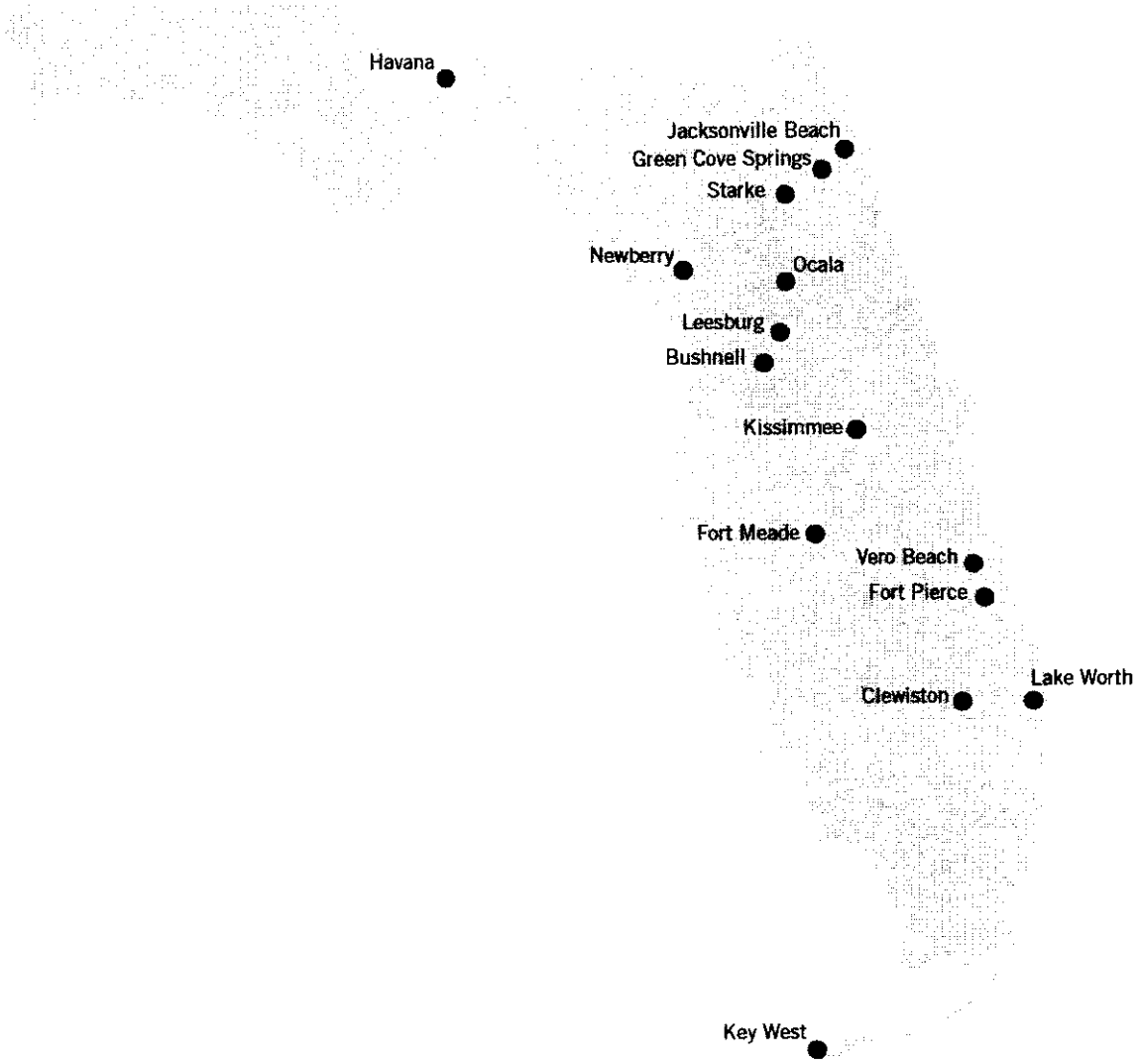


Figure 3-1
ARP Member Cities

Table 3-1
St. Lucie Project Participants

City	Percent Entitlement[1]	City	Percent Entitlement[1]
Alachua	0.431	Clewiston [2]	2.202
Fort Meade [2]	0.336	Fort Pierce [2]	15.206
Green Cove Springs [2]	1.757	Homestead	8.269
Jacksonville Beach [2]	7.329	Kissimmee [2]	9.405
Lake Worth [2]	24.870	Leesburg [2]	2.326
Moore Haven	0.384	Newberry [2]	0.184
New Smyrna Beach	9.884	Starke [2]	2.215
Vero Beach [2]	15.202		

[1] Percent entitlement of FMPA's 8.806 percent undivided ownership share.
[2] ARP member.

Stanton Project

On August 13, 1984, FMPA purchased from the Orlando Utilities Commission (OUC) a 14.8193 percent undivided ownership interest in Stanton Unit 1 (the Stanton Project). Stanton Unit 1 went into commercial operation on July 1, 1987. Six of FMPA's members are participants in the Stanton Project, with the following entitlements as shown in Table 3-2.

Table 3-2
Stanton Project Participants

City	Percent Entitlement[1]	City	Percent Entitlement[1]
Fort Pierce [2]	24.390	Homestead	12.195
Kissimmee [2]	12.195	Lake Worth [2]	16.260
Starke [2]	2.439	Vero Beach [2]	32.521

[1] Percent entitlement of FMPA's 14.8193 percent undivided ownership share.
[2] ARP member.

Tri-City Project

On March 22, 1985, the FMPA Board approved the agreements associated with the Tri-City Project. The Tri-City Project involves the purchase from OUC of an additional 5.3012 percent undivided ownership interest in Stanton Unit 1. Three of FMPA's members are participants in the Tri-City Project, with the following entitlements as shown in Table 3-3.

Table 3-3
Tri-City Project Participants

City	Percent Entitlement[1]
Fort Pierce [2]	22.727
Homestead	22.727
Key West [2]	54.546

[1] Percent entitlement of FMPA's 5.3012 percent undivided ownership share.
[2] ARP member.

Stanton II Project

On June 6, 1991, under the Stanton II Project structure, FMPA purchased from OUC a 23.2367 percent undivided ownership interest in OUC's Stanton Unit 2, a coal fired unit virtually identical to Stanton Unit 1. The unit commenced commercial operation in June 1996. Seven of FMPA's members are participants in the Stanton II Project, with the following entitlements as shown in Table 3-4.

Table 3-4
Stanton II Project Participants

City	Percent Entitlement[1]	City	Percent Entitlement[1]
Fort Pierce [2]	16.4887	Homestead	8.2443
Key West [2]	9.8932	Kissimmee [2]	32.9774
St. Cloud	14.6711	Starke [2]	1.2366
Vero Beach [2]	16.4887		

[1] Percent entitlement of FMPA's 23.2367 percent undivided ownership share.
[2] ARP member.

3.2 FMPA ARP Generation

The ARP supply-side resources consist of a diversified mix of generation ownership and purchase power. These resources are described in the following subsections.

3.2.1 FMPA ARP Solely Owned Generation

This category of resources includes generation that is solely owned by ARP. These resources include the Stock Island CT 2, Stock Island CT 3, Stock Island CT 4, and Treasure Coast Energy Center Unit 1 (TCEC) units. TCEC, located near Fort Pierce, is currently under construction, with commercial operation planned for May 2008. TCEC is a 1x1 combined cycle with a GE 7FA combustion turbine. The unit is forecasted to have a summer capacity of approximately 296 MW. TCEC received site certification from the governor and cabinet in May 2006.

3.2.2 FMPA ARP Jointly Owned Generation

This category of resources includes fossil-fueled and nuclear generation that is jointly owned or purchased by the ARP as well as ARP member participation in the units. The fossil-fueled resources include the Stanton Energy Center (including the Stanton, Tri-City, and Stanton II projects, as well as Stanton Combined Cycle Unit A), Indian River, and Cane Island units.

A number of the ARP members own small amounts of capacity in Progress Energy Florida's (PEF's) Crystal River Unit 3. Likewise, a number of ARP members participate in the St. Lucie Project, which provides them capacity and energy from St. Lucie Unit 2. Capacity from these two nuclear units is classified as "excluded resources" in the ARP. As such, the ARP members pay their own costs associated with the nuclear units and receive the benefits of capacity and energy from these units. The ARP provides the balance of capacity and energy requirements for the members that participate in these nuclear units. The nuclear units are considered in the capacity planning for the ARP.

3.2.3 ARP Member Owned Generation

This category includes generation that is owned by ARP members either solely or jointly. The ARP purchases this capacity from ARP members and then commits and dispatches the generation to meet the total requirements of the ARP. FPUA, KEYS, KUA, Lake Worth, and Vero Beach have member owned generation.

3.3 Purchase Power Contracts

This category includes power purchased directly by the ARP as well as existing purchase power contracts of individual ARP members that were entered into prior to the member joining the ARP. Purchase power generation includes capacity and energy received from suppliers such as PEF, FPL, Calpine, and Southern Power Company. The power purchase contracts are briefly summarized below:

- PEF:
  - FMPA has a power contract with PEF for 30 MW in 2008, 75 MW in 2009, and 120 MW in 2010. The nominated capacity can be adjusted annually and also includes reserves.
- FPL:
  - FMPA has a long-term 45 MW purchase until June 2013. The FPL purchase includes reserves.
- Calpine:
  - FMPA has a contract with Calpine for 100 MW that ends in 2009.
- Southern Power Company:
  - FMPA has a contract to purchase 157 MW of peaking power from Southern Power Company's Oleander plant. The purchase has a term of 20 years.
  - FMPA has a contract to purchase 80 MW from Southern Power Company's (operating as Southern Company-Florida LLC) Stanton A combined cycle unit. The 80 MW includes KUA's capacity purchase. This purchase is currently set to expire in October 2023, with options for further extension. It has been assumed that this contract would be extended for the duration of the study period considered in this Application.

3.4 Unit Retirements

FMPA has identified certain member units for retirement because of their age and inefficiency. In this Application, these units will be considered retired as of the dates presented in Table 3-5.

Table 3-5
FMPA Planned Retirements

Unit Identification	Retirement Date	Summer Capacity Retired (MW)	Total Annual Summer Capacity Retired (MW)
Fort Pierce Unit 7	5/1/2008	29	
Fort Pierce Unit 8	1/24/2008	49	
Fort Pierce Combined Cycle	5/1/2008	31	
Fort Pierce D1 and 2	5/1/2008	5	114
Lake Worth Unit 3	5/1/2011	25	
Lake Worth Unit 5	5/1/2011	8	
Lake Worth GT 1	5/1/2011	27	
Lake Worth GT 2	5/1/2011	20	
Lake Worth D1-5	5/1/2011	10	89(1)
Hansel Combined Cycle	5/1/2012	47	47
Total Retirements			250

(1) Total Annual Summer Capacity Retired does not match sum of individual unit Summer Capacity Retired due to rounding.

3.5 Net ARP Capacity Resources

The ARP existing, approved, and currently planned resource capacity is presented in Table 3-6; values are presented for the years 2008 through 2014. There are no changes to the existing, approved, and currently planned resources after 2014. Table 3-6 reflects the establishment of Contract Rate of Delivery (CROD) by Vero Beach on January 1, 2010, as discussed in Section 13.0.

Table 3-6
ARP's Existing and Approved/Planned Resource Capacity[1]

Generating Resources	Summer Rating					
	2008	2009	2010	2011	2012	2013 - 2027
Excluded Resources (Nuclear)[2]	84	84	73	77	77	77
Stanton Coal Plant[3]	222	222	184	184	184	184
Stanton Combined Cycle Unit A[4]	45	45	45	45	45	45
Cane Island 1-3[4]	383	383	383	383	383	383
Indian River CTs	80	80	80	80	80	80
Stock Island 2-4	75	75	75	75	75	75
Key West Native Generation	41	41	41	41	41	41
Kissimmee Native Generation	47	47	47	47	0	0
Lake Worth Native Generation	89	89	89	0	0	0
Vero Beach Native Generation	138	138	0	0	0	0
TCEC	296	296	296	296	296	296
Total Generating Capacity[5]	1,500	1,500	1,314	1,229	1,182	1,182
Purchased Power						
PEF Partial Requirements	30	75	120	0	0	0
FPL Long-Term Partial Requirements	45	45	45	45	45	0
Calpine Purchase	100	100	0	0	0	0
Stanton A Purchase[6]	80	80	80	80	80	80
Southern Power Company Power Purchase Agreement	157	157	157	157	157	157
Total Purchased Power Resources[5]	412	457	402	282	282	237
Total Resources[5]	1,912	1,957	1,716	1,511	1,463	1,418

[1] Planned capacity prior to commercial operation of the Central Florida Power Project.
[2] Reduction in 2010 reflects the withdrawal of Vero Beach from the ARP. Increase in 2011 reflects planned upgrades.
[3] Reduction in 2010 reflects the withdrawal of Vero Beach from the ARP.
[4] Includes FMPA and KUA ownership capacity.
[5] Sums may not match FMPA totals due to rounding.
[6] Includes FMPA and KUA capacity purchased from Southern Company-Florida, LLC.

3.6 Florida Municipal Power Pool (FMPP)

The FMPP is a power pool composed of three members: OUC, Lakeland Electric, and FMPA. The member generating resources are centrally dispatched to meet the combined FMPP energy requirements.

The FMPP was formed in 1988. FMPP resources include the members' generating units as well as purchase power. Each FMPP member is responsible for maintaining sufficient capacity to serve its own load, including an adequate amount for reserves. The resources are committed and dispatched by OUC, which handles the day-to-day operations of the FMPP.

3.7 Operating and Spinning Reserve Requirements

Florida Reliability Coordinating Council (FRCC) operating reserve is maintained by the combined systems in Florida at a value equal to, or greater than, the summer gross FRCC capability rating of the largest generating unit in service in FRCC. Currently, the operating reserve requirement of the FMPP is 99 MW, which includes 25 MW of spinning reserves. FMPA's share of FMPP's operating reserves is 31.6 MW, which includes 7.9 MW of spinning reserves.

3.8 Transmission System

The Florida electric transmission grid is interconnected by high voltage transmission lines ranging from 69 kV to 500 kV. Florida's electric grid is tied to the rest of the continental United States at the Florida/Georgia/Alabama interface. FPL, PEF, JEA, and the City of Tallahassee own the transmission tie lines at the Florida/Georgia/Alabama interface. ARP members' transmission lines are interconnected with transmission facilities owned by FPL, PEF, OUC, JEA, Seminole Electric Cooperative (SEC), Florida Keys Electric Cooperative Association (FKEC), and TECO.

Capacity and Energy (C&E) resources for the ARP are transmitted to ARP members utilizing the transmission systems of FPL, PEF, TECO, and OUC. C&E resources for the cities of Jacksonville Beach, Green Cove Springs, Clewiston, Fort Pierce, Key West, Lake Worth, Starke, and Vero Beach are delivered by FPL's transmission system. C&E resources for the cities of Ocala, Leesburg, Bushnell, Newberry, and Havana are delivered by the PEF transmission system. C&E resources for KUA are delivered by the transmission systems of FPL, PEF, and OUC. C&E resources for the City of Fort Meade are delivered by the PEF and TECO transmission systems.

3.8.1 Member Transmission Systems

FPUA

FPUA operates an internal, looped 69 kV transmission system for system load and a 118 MW local power generating plant (shown in Table 3-5 with a retirement date of May 1, 2008). There are two interconnections with other utilities, both operated at 138 kV. FPUA's Hartman Substation interconnects to FPL's Midway and Emerson Substations. The second interconnection is from FPUA's Garden City (No. 2) Substation to County Line Substation No. 20, connected by a 7.5 mile, single-circuit, 138 kV line. FPUA and the City of Vero Beach jointly own County Line Substation, the 138 kV line connecting to Emerson Substation, and some parts of the tie between the two cities.

KEYS

KEYS owns, operates, and maintains an electric generation, transmission, and distribution system that supplies electric power and energy south of FKEC's Marathon Substation to the City of Key West. KEYS and FKEC jointly own a 64 mile, 138 kV transmission tie line from FKEC's Marathon Substation that interconnects to FPL's Florida City Substation at the Dade/Monroe county line. In addition, a second interconnection with FPL was completed in 1995, which consists of a jointly owned 21 mile, 138 kV tie line between the FKEC's Tavernier and Florida City Substations at the Dade/Monroe county line. KEYS owns a 49.2 mile, 138 kV radial transmission line from Marathon Substation to KEYS' Stock Island Substation. Two autotransformers at the Stock Island Substation provide transformation between 138 kV and 69 kV. KEYS has five 69 kV and four 138 kV substations that supply power at 13.8 and 4.16 kV to its distribution system. KEYS owns approximately 227 miles of 13.8 kV distribution line.

Lake Worth

The City of Lake Worth Utilities (LWU) has one 138 kV interconnection with FPL at the LWU-owned Hypoluxo Switching Station. A 3 mile radial 138 kV transmission line connects the Hypoluxo Switching Station to LWU's Main Plant Substation. In addition, a 2.4 mile radial 138 kV transmission line connects the Main Plant Substation to LWU's Canal Substation. Two 138/26 kV autotransformers are located at the Main Plant Substation, and one 138/26 kV autotransformer is located at Canal Substation. The utility owns and operates an internal 26 kV sub-transmission system to serve system load.

KUA

KUA-owned generation and purchased capacity is delivered through 230 kV and 69 kV transmission lines. KUA's 230 kV and 69 kV transmission system includes interconnections with PEF, OUC, TECO, and the City of St. Cloud. KUA owns and operates 24.6 circuit miles of 230 kV and 46.9 circuit miles of 69 kV transmission lines. KUA and FMPA jointly own 21.6 circuit miles of 230 kV lines out of Cane Island Power Park. Electric capacity and energy supplied from KUA-owned generation and purchased capacity is delivered through 230 kV and 69 kV transmission lines to nine distribution substations. KUA has direct transmission interconnections with (1) PEF at PEF's 230 kV Intercession City Substation, 69 kV Lake Bryan Substation, and 69 kV Meadow Wood South Substation; (2) OUC at OUC's 230 kV Taft Substation and TECO/OUC's 230 kV Osceola Substation from the Cane Island Substation; and (3) the City of St. Cloud at KUA's 69 kV Carl A. Wall Substation.

Ocala

Ocala Electric Utility (OEU) owns and operates its bulk power supply system, which consists of three 230 kV to 69 kV substations, 13 miles of radial 230 kV and 48 miles of 69 kV transmission loop, and 18 distribution substations delivering power at 12.47 kV. The distribution system consists of 773 miles of overhead lines and 302 miles of underground lines.

OEU's 230 kV transmission system interconnects with PEF's Silver Springs Switching Station and Seminole Electric Cooperative Incorporated's (SECI's) Silver Springs North Switching Station. OEU's Dearmin Substation ties at PEF's Silver Springs Switching Station and OEU's Ergle Substation ties at SECI's Silver Springs North Switching Station. OEU also has a 69 kV tie from the Airport Substation with Sumter Electric Cooperative's Martel Substation. In addition, OEU owns and operates a 13 mile radial 230 kV transmission line from Ergle Substation to Shaw Substation. OEU is planning to add a second 230 kV tie by rerouting the existing Shaw to Ergle 230 kV line from Shaw Substation to a direct radial connecting to SECI's Silver Springs North Switching Station.

Vero Beach

The City of Vero Beach owns and operates an internal, looped, 69 kV transmission system for system load and a 138 MW local power generating plant. The City of Vero Beach has two 138 kV interconnections with FPL and one with FPUA. The City of Vero Beach's interconnection with FPL is at the City of Vero Beach's West Substation No. 7. The City of Vero Beach also has a second FPL interconnection from

County Line Substation No. 20. County Line Substation No. 20 is connected by two separate, single-circuit, 138 kV transmission lines to FPL's Emerson 230/138 kV substation and FPUA's Garden City (No. 2) Substation. The City of Vero Beach and FPUA jointly own County Line Substation No. 20, the connecting lines to FPL's Emerson Station, and some part of the tie between the two municipal utilities.

3.8.2 Transmission Agreements

FPL

The Network Service Agreement with FPL was executed in March 1996, and was subsequently amended to both conform to the Federal Energy Regulatory Commission's (FERC's) Pro Forma Tariff and to add additional members to the ARP. The FPL agreement provides for network transmission service for the ARP member cities located in FPL's service territory.

PEF

To provide transmission wheeling service for ARP member cities located in PEF's service territory, FMPA operates under an existing agreement with PEF. This agreement was executed in April 1985, and provides for network type transmission services.

OUC

OUC provides transmission service for the delivery of power and energy from FMPA's ownership in Stanton Unit 1, Stanton Unit 2, Stanton A combined cycle, and the Indian River combustion turbine units to the FPL and PEF interconnections for subsequent delivery to the ARP. Rates for such transmission wheeling service are based on OUC's costs of providing such transmission wheeling service and under the terms and conditions of the OUC-FMPA Firm Transmission Service contracts for the ARP.

3.9 Load and Electrical Characteristics

FMPA experiences both summer and winter demand peaks. Summer demands, which peak in the afternoons, are longer in duration than winter demands, which typically peak in the morning. In addition, summer peaks typically occur when many generation resources are experiencing ambient temperature performance impacts. As a result, the summer peaks govern FMPA planning capacity requirements.

3.10 Description of Existing Renewable Projects

3.10.1 FMPA Renewable Projects

FMPA purchases the electric output of the US Sugar plant in Clewiston, Florida. The plant operates on bagasse as its fuel source. Bagasse is the residue of sugar cane production, and its burning may be considered carbon dioxide (CO_2) neutral because CO_2 emissions from bagasse are equal to the CO_2 absorbed from the atmosphere by the sugar cane during its growing phase. US Sugar uses the bagasse to fuel its generation plants to provide power for its processes, and FMPA purchases the excess (unused) power from US Sugar's generators. In addition to the FMPA-purchased energy, the energy produced by US Sugar from bagasse offsets the energy that would have been produced by fossil fuels.

FMPA owns a portion of Stanton Energy Center Units 1 and 2, as described earlier in this section. These units have the capability to burn landfill gas from a nearby landfill. Through its contract with OUC, the landfill provides methane gas as a supplemental fuel source for Stanton Units 1 and 2.

3.10.2 ARP Member Renewable Projects

KEYS offers its residential and commercial customers the opportunity to participate in the GO GREEN program. The optional program involves contributing as little as $10 per month, and two "blends" of renewable energy are offered. Program participants will not be directly powered by renewable energy, but their participation will contribute to energy production from renewable sources somewhere in Florida (through the Florida Ever Green™ blend) or elsewhere in the United States (through the USA Green™ blend).

4.0 Economic Parameters

This section presents the economic evaluation criteria and methodology used to evaluate the economics of Cane Island 4 as part of FMPA's least-cost expansion plan to satisfy forecast capacity requirements throughout the 20 year evaluation period.

4.1 Inflation and Escalation Rates

The general inflation rate, construction cost escalation rate, fixed O&M escalation rate, and nonfuel variable O&M escalation rate were each assumed to be 2.3 percent.

4.2 Municipal Bond Interest Rate

The long-term tax exempt municipal bond interest rate was assumed to be 5.0 percent.

4.3 Present Worth Discount Rate

The present worth discount rate was assumed to be equal to the tax exempt municipal bond interest rate of 5.0 percent.

4.4 Interest During Construction Interest Rate

The interest during construction (IDC) rate was assumed to be 5.0 percent.

4.5 Levelized Fixed Charge Rate

The fixed charge rate (FCR), represents the sum of a project's fixed charges as a percent of the initial investment cost. When the FCR is applied to the initial investment, the product equals the revenue requirements needed to offset the fixed charges during a given year. A separate FCR can be calculated and applied to each year of an economic analysis, but it is common practice to use a single, levelized FCR that has the same present value as the year-by-year fixed charge rate.

Different generating technologies are assumed to have different economic lives and, therefore, different financing terms. Simple cycle combustion turbines are assumed to have a 25 year financing term, while natural gas fired combined cycle units are assumed to be financed over 30 years. Given the various economic lives and corresponding financing terms, different levelized FCRs were developed. All levelized FCR calculations assume a 2.0 percent bond issuance fee and include an assumed 0.50 percent annual property insurance cost and a 6 month debt service reserve fund

earning interest at an interest rate equal to the bond interest rate[1]. The resulting 25 year fixed charge rate is 7.824 percent, and the 30 year fixed charge rate is 7.194 percent.

[1] The debt service reserve fund is a fund to cover 6 months of debt service obligations associated with capital expenditures.

5.0 Forecast of Electrical Demand and Consumption

5.1 Introduction

Under the ARP structure, FMPA agrees to meet all of the ARP members' power requirements. To secure sufficient capacity and energy, FMPA forecasts each ARP member's electrical power demand and energy requirements on an individual basis and integrates the results into a forecast for the entire ARP. The following discussion summarizes the load forecasting process and the results of the ARP members' load forecast.

5.2 Load Forecast Process

FMPA prepares its load and energy forecast by month and summarizes the forecast annually. The load and energy forecast includes projections of customers, demand, and energy sales by rate classification for each of the ARP members. The forecast process includes existing ARP member cities that FMPA currently supplies and ARP members that FMPA is scheduled to begin supplying in the future. Forecasts are prepared on an individual member basis and are then aggregated into projections of the total ARP demand and energy requirements.

Figure 5-1 illustrates the ARP members' load forecast process.

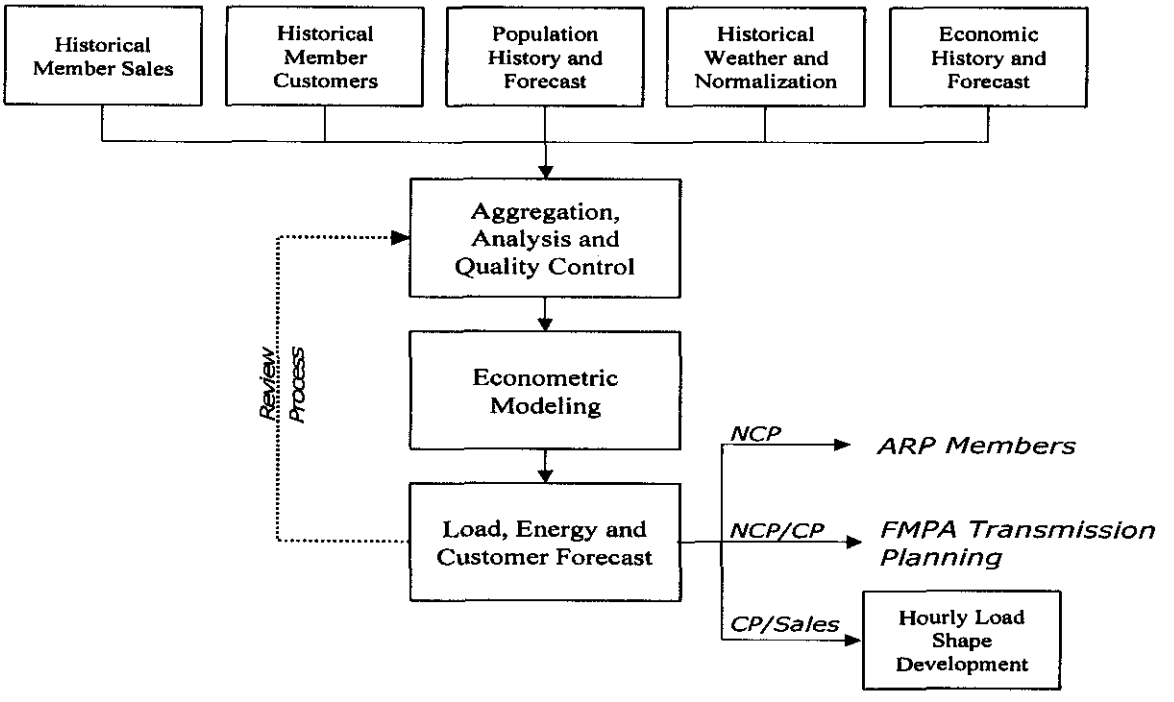


Figure 5-1
Load Forecast Process

In addition to the base case load and energy forecast, FMPA has prepared high and low case forecasts, which are intended to capture the majority of the uncertainty in certain driving variables, for each of the ARP members.

5.3 Load Forecast Overview

FMPA retained R. W. Beck, Inc. (Beck) to prepare a forecast of peak load and net energy for the ARP members. The load and energy requirement forecast is a critical input to many utility processes including, but not limited to, generation expansion planning, fuel and purchased power budgeting, transmission planning, financial planning and budgeting, and staffing. In addition, the load and energy forecast is submitted to the Florida Public Service Commission (FPSC) as part of the Ten Year Site Plan. Consequently, a rigorous and detailed process that relies on recognized standards of practice, as well as a thorough review of results by various parties, is essential to operations and long-term planning.

The load and energy forecast prepared by Beck (the Forecast) was prepared for a 20 year period, encompassing calendar years 2007 through 2026. The Forecast was prepared on a monthly basis using municipal utility data provided to FMPA by the ARP members and load data maintained by FMPA. Historical and projected economic and demographic data was provided by Economy.com, a nationally recognized provider of economic data. Also, Beck relied on ARP members and their staffs for information regarding local economic and demographic issues specific to each member. As discussed in Subsection 3.1.2, the load for the City of Fort Meade is currently served through a full requirements agreement with Tampa Electric Company (TECO). When the Fort Meade/TECO agreement terminates in January 2009, FMPA will serve the City of Fort Meade from ARP's portfolio of power supply resources. The Forecast reflects the addition of the Fort Meade requirements beginning in 2009. As discussed in Section 13.0, the City of Vero Beach has provided FMPA with its Notice of Establishment of a Contract Rate of Delivery (CROD). The Forecast was performed assuming that Vero Beach's CROD becomes effective on January 1, 2010.

In addition to the base case Forecast, Beck prepared high and low case forecasts of winter and summer peak demand and net energy for load (NEL). The high and low case forecasts reflect varying assumptions regarding the future values for population and measures of economic activity. The high and low case forecasts are intended to capture 90 percent of the uncertainty in these driving variables throughout the forecast horizon.

5.4 Load Forecast Methodology

The forecast of peak demand and NEL to be supplied by ARP relies on an econometric forecast of each ARP member's retail sales, combined with various assumptions regarding loss, load, and coincidence factors, generally based on the recent historical values for such factors, and summed across the ARP members.

Econometric forecasting makes use of regression to establish historical relationships between energy consumption and various explanatory variables based on fundamental economic theory and experience. In this approach, the significance of historical relationships is evaluated using commonly accepted statistical measures. Models that, in the view of the analyst, best explain the historical variation of energy consumption are selected. These historical relationships are generally assumed to continue into the future, barring any specific information or assumptions to the contrary. The selected models are then populated with projections of explanatory variables, resulting in projections of energy requirements.

Econometric forecasting can be a more reliable technique for long-term forecasting than trend-based approaches and other techniques, because the approach results in an explanation of variations in load rather than simply an extrapolation of history. As a result of this approach, utilities are more likely to anticipate departures from historical trends in energy consumption, given accurate projections of the driving variables. In addition, understanding the underlying relationships that affect energy consumption allows utilities to perform scenario and risk analyses, thereby improving decisions. The high and low scenarios developed as part of the forecast process are examples of this capability.

5.5 Model Specification

Forecasts of monthly sales were prepared by rate classification for each ARP member. In some cases, rate classifications were combined to eliminate the effects of class migration or redefinition. In this way, greater stability is provided in the historical period upon which statistical relationships are based.

For the residential class, the analysis of electric sales was separated into residential usage per customer and the number of customers, the product of which is total residential sales. This process is common for homogenous customer groups. For other rate classifications, the total sales series is the primary forecasted variable, and the customer forecast is generated for reporting purposes and to check the sensibility of the sales forecast.

Residential class models typically reflect that energy sales are dependent on, or driven by: (i) the number of residential customers, (ii) real personal income per household, (iii) real electricity prices, and (iv) weather variables. The number of

residential customers was projected on the basis of the estimated historical relationship between the number of residential customers of the ARP members and the number of households in the ARP member's county.

For the general service class models, the econometric models reflect that energy requirements are best explained by: (i) real retail sales, total personal income, or gross domestic product (GDP) as a measure of economic activity and population in and around the ARP member's service territory, (ii) the real price of electricity, and (iii) weather variables. In the case of the general service non-demand class, retail sales was typically selected as the long-term driving variable either because it performed better by certain measures or because the resulting forecast was more sensible. Similarly, for the general service demand and industrial classes, total personal income or GDP was typically selected, except in cases where the forecast was based on an assumption (e.g., Clewiston's largest customer, US Sugar, and the US Navy base in Key West's service area).

Weather variables included heating and cooling degree-days (HDD and CDD, respectively) for the current month and for the prior month. Lagged degree-day variables were included to account for the typical billing cycle offset from calendar data. In other words, sales that are billed in any particular month are typically made up of electricity that was used during some portion of the current month and of the prior month.

5.6 Projection of Net Energy for Load and Peak Demand

5.6.1 ARP Member NEL and Peak Demand

The forecast of sales for each rate classification were summed to equal the total sales of each ARP member. Assumed ARP member distribution loss factors, typically based on a 5 year average of historical loss factors, were then applied to the total sales to derive monthly NEL measured at the delivery points of the ARP members. To the extent that historical loss factors were deemed anomalous, they were excluded from these averages.

Projections of summer and winter noncoincident peak (NCP) demand were developed by applying projected annual load factors to the forecasted NEL on an ARP member system basis. The projected load factors are based on the average relationship between annual NEL and the seasonal peak demand generally over the period 1997 to 2006 (i.e., a 10 year average).

Monthly peak demand was based on the average relationship between each monthly peak and the appropriate seasonal peak. This average relationship was computed after ranking the historical demand data within the summer and winter seasons and reassigning peak demands to each month based on the typical ranking of that month

compared to the seasonal peak. This process avoids the distortion of the averages due to randomness as to the months in which peak weather conditions occur within each season. For example, a summer peak period can occur during July or August of any year. It is important that the shape of the peak demands reflects that only one of those two months is the peak month and that the other is typically some percentage less.

Projected coincident peak demands related to the total ARP, the ARP member groups, and the transmission providers were derived from projected NCP demand and monthly coincidence factors averaged generally over a 5 year period (2002 to 2006).

5.6.2 *Transmission System Losses*

The ARP members are supplied over the transmission systems of Florida Power & Light (FPL) and Progress Energy Florida (PEF). KUA is not a transmission customer of either FPL or PEF, so it is treated separately in calculating transmission system losses. Based on the transmission agreement in place with FPL, FMPA is charged for losses of 2.19 percent and supplies its own losses. Accordingly, load of ARP members in FPL's service territory is adjusted upward to account for 2.19 percent losses. The current agreement with PEF does not require FMPA to generate losses; however, FMPA compensates PEF for losses incurred on the PEF system. The current agreement with PEF ends in 2010. At that time, FMPA is expected to enter into another agreement similar to the FPL agreement where FMPA is expected to supply its own losses at an assumed loss factor of 2.17 percent. For 2011 and beyond, the load of ARP members on the PEF system is adjusted upward to account for 2.17 percent losses. Transmission losses to the KUA system were calculated using a 0.75 percent loss factor.

5.7 Principal Considerations and Assumptions

The development of the Forecast was based upon the following principal considerations and assumptions:

- The future influence on energy sales of the economic, demographic, and weather factors, on which the econometric models are based, was assumed to be similar to the estimated influence of such factors generally over the period 1992 through 2006.
- Although the econometric models implicitly account for the historical relationships between energy usage and the following factors to the extent they have occurred in the past, the Forecast does not explicitly reflect extraordinary potential future effects of: (a) increases in appliance design efficiency or building insulation standards, (b) development of substitute energy sources, (c) consumers switching to traditional or new types of

electrical appliances from other alternatives (e.g., electric vehicles), (d) consumers switching from electrical appliances to other alternatives, or (e) variations in load that might result from legal, legislative, regulatory, or policy actions.

- The recent average historical relationships between annual summer and winter noncoincident demands and annual NEL and between monthly NCP demands and annual winter and summer NCP demands were assumed to represent reasonable approximations of future load relationships between demands and energy requirements.

The Forecast also relies on historical and projected data from third parties and certain derivations of such data as discussed in the subsections below.

5.7.1 Historical ARP Member Data

Data for each ARP member on numbers of customer accounts, electric sales, and revenues by major rate classification are provided periodically to FMPA by the ARP members. The Forecast relies on such data maintained by FMPA spanning January 1992 through March 2007 (the Study Period). For a small portion of the Study Period, only total revenues were available, and the average revenue for each rate classification analyzed was assumed to vary the same as the total member system average revenue over that period.

5.7.2 Weather Data

Historical weather data has been provided by the National Oceanic and Atmospheric Administration (NOAA). Weather stations for which historical weather was obtained were selected on the basis of their quality and proximity to the ARP members. In most cases, the closest first-order weather station was the best source of weather data. First-order weather stations (usually airports) generally provide the highest quality and most reliable weather data.

The influence on electricity sales of weather has been represented through the use of two data series: HDD and CDD. Degree-days are derived by comparing the average daily temperature and a base temperature, typically 65° F, which was the base relied on herein. To the extent the average daily temperature exceeds 65° F, the difference between that average temperature and the base is the number of CDD for the day in question. Conversely, HDDs result from average daily temperatures which are below 65° F. Heating and cooling degree-days are then summed over the period of interest, in this case, months.

Weather conditions for the projected period are based on the most recent 30 year normals, as computed by NOAA for the period 1971 through 2000.

5.7.3 Economic Data

Economy.com, a nationally recognized provider of economic data, provided both historical and projected economic and demographic data. The data included economic and demographic data for the 16 counties in which the ARP members' service territories reside (the service territory of Beaches Energy Services includes portions of both Duval and St. Johns Counties). These data included county population, households, employment, personal income, retail sales, and GDP. Although all data were not necessarily utilized in each of the forecast equations, each was examined for its potential to explain changes in the ARP members' historical electric sales.

Historical and projected rates of change in two of the key economic drivers (i.e., number of households and personal income) in the Forecast are summarized in Table 5-1. Note: Personal income refers to the total income earned by the population in a county rather than average personal income per capita.

Table 5-1
Historical and Projected Growth (%) in Households and Personal Income

	Number of Households				Personal Income			
ARP Members	1995-2006	2007-2009	2010-2016	2017-2026	1995-2006	2007-2009	2010-2016	2017-2026
Bushnell	5.5	3.9	3.5	2.5	7.5	6.3	5.9	5.0
Clewiston	1.8	2.5	2.3	1.6	2.0	2.0	1.8	1.4
Fort Meade	2.1	1.7	2.3	2.4	3.8	3.3	4.5	5.3
Fort Pierce	3.5	3.2	4.1	3.2	3.8	5.3	5.2	2.9
Green Cove Springs	3.7	3.0	3.3	2.5	4.8	4.9	5.0	4.8
Havana	1.0	1.4	2.1	1.9	2.5	3.2	4.1	4.0
Jacksonville Beach	1.9	1.3	1.7	1.4	3.8	3.8	4.0	4.2
Key West[1]	-0.6	-0.3	-0.5	-0.9	2.2	2.3	2.1	1.7
Kissimmee	5.1	4.5	4.7	3.9	6.3	4.0	3.9	3.9
Lake Worth	2.0	2.1	3.1	3.0	3.8	3.5	4.2	4.3
Leesburg	4.6	4.1	4.5	3.8	5.7	3.4	3.2	3.3
Newberry	1.1	1.4	1.9	1.8	2.9	4.3	4.8	4.1
Ocala	3.0	4.3	4.1	3.5	4.4	4.3	5.1	4.4
Starke	1.5	1.7	1.7	1.1	3.0	2.0	1.9	1.6
Vero Beach	2.5	2.2	3.2	3.2	4.4	1.6	2.5	2.8

[1]Reported data reflects permanent residents only. Monroe County, the county that comprises Key West, has a significant percentage of seasonal residents, which has represented a growing portion of total residents over the recent historical period. While the projection reflects a decline in the number of permanent residents, this does not imply a decline in total residents.

5.7.4 *Real Electricity Price Data*

The real price of electricity was derived from a 12 month moving average of real average revenue for each ARP member, normalized for inflation based on the consumer price index (CPI). To the extent that average revenue data specific to a certain rate classification was unavailable, it was assumed to follow the trend of total average revenue of the ARP member. Projected electricity prices were assumed to increase at the rate of inflation. Consequently, the real price was projected to be essentially constant.

5.8 Uncertainty of the Forecast

The base case Forecast relies on a set of assumptions, provided by Economy.com, about future population and economic activity in the counties surrounding the ARP members. However, such projections are unlikely to exactly match the resulting data as future periods become history. While it is sensible to place significant weight on the base case, the Forecast also includes two scenarios reflecting higher and lower projections of population and economic activity.

Given that Economy.com does not publish information regarding the potential error of its projections, the scenarios rely on such statistics published by another provider, Woods & Poole Economics, Inc. (Woods & Poole), which relies on the same underlying data set and a similar economic forecasting methodology. Woods & Poole publishes several statistics that relate to the average amount by which various projections it has provided in the past are different from actual results. These statistics are used to develop optimistic and pessimistic scenarios of the trends in economic activity and population representing approximately 90 percent of potential outcomes.

The statistics utilized to generate the alternative scenarios are associated with economic projections at the state level, so that the forecasts of each ARP member can be summed to represent a consistent case for the ARP. However, the historical growth rates of the ARP members are not perfectly correlated. By its very nature, the aggregate economy and population comprising the load supplied from the ARP will exhibit significantly less volatility than any individual ARP member's service area. Therefore, care should be exercised when using these alternative growth scenarios because the plausible range of results for any individual ARP member may be considerably wider than that shown.

The ranges of resulting load forecasts imply that the load projections of the individual ARP members exhibit different levels of sensitivity to variation in the driving variables. This is due to differences in: (i) the responsiveness of the energy requirements of the ARP members to changes in the input assumptions and (ii) the percentage of the total ARP member sales that certain large customers comprise of various ARP members'

total loads. These large customers' energy sales were forecasted separately based on information provided by the ARP members or FMPA staff, and such forecasts were assumed to be independent of changes in the local economy. Although this assumption is somewhat simplified, it does illustrate that the energy requirements of some of the ARP members are very dependent on the fortunes and actions of a few large customers.

Table 5-2 provides the amount by which Economy.com projections were adjusted from the base case assumptions, to develop the high and low cases. This amount of variation is intended to represent 90 percent of potential outcomes (1.7 standard deviations). Other economic data, such as retail sales and GDP, were assumed to vary to the same degree as income. As expected, the amount of potential variation is shown to grow through time, because uncertainty in these variables varies in rough proportion to the forecast horizon.

Table 5-2
Economic and Demographic Uncertainty

Year	Population (Percent)	Employment (Percent)	Income (Percent)	Income per Capita (Percent)
2008	3.4	5.1	7.7	6.4
2009	4.3	6.8	8.5	6.8
2010	5.1	8.5	9.4	7.2
2011	6.0	10.2	10.2	7.7
2012	6.8	11.9	11.1	8.1
2013	7.7	13.6	11.9	8.5
2014	8.5	15.3	12.8	8.9
2015	9.4	17.0	13.6	9.4
2016	10.2	18.7	14.5	9.8
2017	11.1	20.4	15.3	10.2
2018	11.9	22.1	16.2	10.6
2019	12.8	23.8	17.0	11.1
2020	13.6	25.5	17.9	11.5
2021	14.5	27.2	18.7	11.9
2022	15.3	28.9	19.6	12.3
2023	16.2	30.6	20.4	12.8
2024	17.0	32.3	21.3	13.2
2025	17.9	34.0	22.1	13.6
2026	18.7	35.7	23.0	14.0

5.9 Overview of Results

The following subsections present the summer peak demand, winter peak demand, and NEL for the base, high, and low load forecasts for the period 2008 through 2026. These results include transmission losses.

5.9.1 Base Load Forecast

The 2008 forecasted summer peak demand is 1,545 MW, winter peak demand is 1,427 MW, and annual NEL is 7,655 GWh. The 2026 forecasted summer peak demand is 2,077 MW, winter peak demand is 1,878 MW, and annual NEL is 10,233 GWh. The summer peak demand is projected to grow at a rate of 3.2 percent from 2008 to 2009 and at an average annual rate of 2.2 percent from 2010 through 2026. The winter peak demand is projected to grow at a rate of 3.2 percent from 2008 to 2009 and at an average annual rate of 2.2 percent from 2010 through 2026. The NEL is expected to grow at a rate of 3.1 percent from 2008 to 2009 and at an average annual rate of 2.2 percent from 2010 through 2026. The growth from 2008 to 2009 includes the addition of the Fort Meade load following the expiration of its existing full requirements agreement with TECO. Growth rates have been shown separately for the 2008 to 2009 and 2010 through 2026 periods to avoid distortion because of Vero Beach's establishment of CROD, effective January 1, 2010. All values decrease from 2009 to 2010 as a result of this removal of Vero Beach loads beginning in 2010. Detailed results for the base case Forecast are summarized in Table 5-3.

5.9.2 High and Low Load Forecasts

The base case Forecast consists of an estimate of the future values for each of the dependent variables, the electricity sales by rate classification for each of the members, and all of the derived load determinants, including NEL and peak demand. The base case Forecast represents the most likely estimate of future load levels. However, there is significant uncertainty in those projections, a large portion of which is related to the uncertainty in the projections of the independent variables. To account for this uncertainty, high and low forecasts were developed by simulating the energy sales models using varying assumptions regarding population and economic activity as discussed in Section 5.7. The remaining load determinants were then derived from these alternative forecasts of energy sales by classification, as in the base case Forecast. The high and low forecasts combine to form a band of uncertainty that is intended to capture approximately 90 percent (1.7 standard deviations) of occurrences. Detailed results for the high and low forecast are summarized in Table 5-4.

Table 5-3
Total ARP Demand and Energy Forecast
Base Case[1]

Year	Winter Peak (MW)	Summer Peak (MW)	NEL (GWh)
2008	1,427	1,545	7,655
2009	1,473	1,593	7,896
2010	1,319	1,462	7,237
2011	1,359	1,506	7,451
2012	1,389	1,539	7,612
2013	1,421	1,574	7,783
2014	1,453	1,610	7,960
2015	1,487	1,647	8,141
2016	1,522	1,685	8,326
2017	1,556	1,723	8,511
2018	1,591	1,761	8,695
2019	1,626	1,799	8,881
2020	1,661	1,838	9,070
2021	1,697	1,877	9,261
2022	1,733	1,917	9,454
2023	1,769	1,957	9,648
2024	1,805	1,997	9,843
2025	1,842	2,037	10,037
2026	1,878	2,077	10,233
Annual Growth Rates (%)			
2008-2009	3.2	3.2	3.1
2010-2026	2.2	2.2	2.2

[1]Forecast peak demands and NEL do not include any capacity or energy associated with serving Vero Beach after the CROD becomes effective.

Table 5-4
Total ARP Demand and Energy Forecast
High and Low Forecasts[1]

Year	High Forecast			Low Forecast		
	Winter Peak (MW)	Summer Peak (MW)	NEL (GWh)	Winter Peak (MW)	Summer Peak (MW)	NEL (GWh)
2008	1,457	1,579	7,842	1,396	1,509	7,466
2009	1,515	1,641	8,146	1,429	1,545	7,642
2010	1,365	1,515	7,514	1,271	1,407	6,955
2011	1,416	1,571	7,785	1,301	1440	7,111
2012	1,456	1,616	8,003	1,321	1,462	7,215
2013	1,498	1,662	8,232	1,341	1,484	7,325
2014	1,541	1,710	8,470	1,363	1,507	7,439
2015	1,586	1,760	8,715	1,385	1,531	7,556
2016	1,632	1,811	8,965	1,407	1,556	7,672
2017	1,679	1,863	9,219	1,429	1,580	7,787
2018	1,726	1,915	9,473	1,451	1,603	7,899
2019	1,774	1,968	9,732	1,472	1,626	8,009
2020	1,823	2,022	9,997	1,493	1,649	8,120
2021	1,873	2,077	10,267	1,515	1,672	8,230
2022	1,924	2,134	10,541	1,535	1,695	8,339
2023	1,975	2,191	10,820	1,556	1,717	8,446
2024	2,027	2,249	11,101	1,576	1,739	8,550
2025	2,079	2,307	11,386	1,596	1,760	8,652
2026	2,132	2,366	11,673	1,615	1,781	8,752
Annual Growth Rates (%)						
2008-2009	3.9	3.9	3.9	2.4	2.3	2.4
2010-2026	2.8	2.8	2.8	1.5	1.5	1.4

[1]Forecast peak demands and NEL do not include any capacity or energy associated with serving Vero Beach after the CROD becomes effective.

5.10 Price Elasticity of the Load Forecast

The econometric models that form the basis of the Forecast include the price of electricity as an important driver of load, typically through the use of a 12 month moving average of historical real average revenue. However, the Forecast assumes that the retail cost of electricity to the customers of the ARP members increases at the rate of general inflation, resulting in essentially flat real prices. Therefore, aside from the delayed influence of price changes in the recent past, which tends to depress loads somewhat, future loads are assumed to be generally unaffected by the cost of electricity.

To the extent that changes in the cost of electricity deviate significantly from the path of general inflation, actual future loads can be expected to deviate from the Forecast. A useful measure of the amount by which loads are impacted by changes in electricity prices is referred to as "elasticity." Elasticity is defined as the percentage by which one variable changes as the result of a 1 percent change in another, all else equal. The numerous econometric models that drive the Forecast reflect elasticity estimates that vary from approximately -0.5 to 0.0 (i.e., no discernable influence), which is similar to other empirical work performed in the electric utility industry. Assuming an average elasticity of -0.2, a 20 percent increase in the real price of electricity from recent levels, which are already quite elevated from the level exhibited 2 to 3 years ago, might result in loads that are approximately 4 percent lower. Similarly, a 20 percent decrease in the real price of electricity would result in loads that are 4 percent higher.

6.0 Natural Gas Availability

This section discusses the availability of natural gas based on information from the U.S. Energy Information Administration (EIA) and other sources. Due to projected increases in natural gas production and the importation of liquefied natural gas (LNG), natural gas supplies are projected to meet growing demand in the United States. There also are several new natural gas storage and pipeline projects that will help facilitate the increase in supply of natural gas to the Southeast region. For these and other reasons, Cane Island Unit 4 will have a reliable supply of natural gas.

6.1 Natural Gas Production

The fuel price projections presented in Section 7.0 for natural gas, fuel oil, and coal used in this Application were developed based on those included in the US Energy Information Administration (EIA) Annual Energy Outlook 2007 (AEO2007). AEO 2007 presents projections of energy supply, demand, and prices through 2030. The projections presented within AEO2007 are based on results from the EIA's National Energy Modeling System (NEMS). NEMS is a computer-based, energy-economy modeling system of US energy markets and projects the production, imports, conversion, consumption, and prices of energy, subject to a variety of assumptions related to macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, technology characteristics, and demographics.

The projected availability of natural gas relative to the fuel price projections in Section 7.0 is based on NEMS. The North American natural gas market is experiencing significant future natural gas development and production possibilities. Legislative and regulatory influences along with the impact of technology improvement is projected to drive the rate of natural gas field development and production. The Lower 48 Outer Continental Shelf (OCS) has significant leasing and development possibilities as presented in the AEO2007 reference case. The natural gas potential of available leasing and development fields along with the anticipated moratoria expiration of unavailable leasing and development fields provide significant potential for natural gas production.

Additionally, the impact of the proposed Alaska pipeline which will transport natural gas produced in Alaska to the lower 48 states and considerable offshore natural gas resources in the Gulf of Mexico is projected to provide supplementary natural gas domestically.

The natural gas production possibilities presented in the AEO2007 reference case provide suitable natural gas supply availability for Cane Island 4 based on the pricing methodology determined to transport natural gas into the FRCC region. The following sections present the AEO2007 reference case projections of traditional gas production.

6.1.1 *Future Natural Gas Production*

Total domestic natural gas production, including supplemental natural gas supplies, is projected to increase from 18.3 tcf in 2005 to 21.1 tcf in 2022, before declining to 20.6 tcf in 2030 in the AEO2007 reference case. Lower natural gas consumption in the last 18 years of the projection results in lower domestic natural gas production—primarily, offshore and onshore nonassociated conventional production—in the AEO2007 reference case.

In the AEO2007 reference case, lower 48 offshore production of natural gas grows from 3.4 tcf in 2005 to a peak of 4.6 tcf in 2015 as new resources come online in the Gulf of Mexico. After 2015, lower 48 offshore production declines to 3.3 tcf in 2030, as investment is projected to be inadequate to maintain production levels.

A large proportion of the onshore lower 48 conventional natural gas resource base has been discovered. Discoveries of new conventional natural gas reservoirs are expected to be smaller and deeper, and thus more expensive and riskier to develop and produce. Accordingly, total lower 48 onshore conventional natural gas production is projected to decline in the AEO2007 reference case from 6.4 tcf in 2005 to 4.9 tcf in 2030.

Incremental production of lower 48 onshore natural gas is projected to come primarily from unconventional resources, including coalbed methane, tight sandstones, and gas shales. Lower 48 unconventional production increases in the reference case from 8.0 tcf in 2005 to 10.2 tcf in 2030, when it accounts for 50 percent of projected domestic U.S. natural gas production.

The Alaska natural gas pipeline is expected to begin transporting natural gas to the lower 48 States in 2018. In 2030, Alaska's projected natural gas production totals 2.2 tcf in the reference case.

Considerable natural gas resources remain in the offshore Gulf of Mexico, especially in the deep waters. Deepwater natural gas production in the Gulf of Mexico is projected to increase in the reference case from 1.4 tcf in 2005 to a peak volume of 3.1 tcf in 2015, then decline to 2.1 tcf in 2030. Production in the shallow waters declines throughout the projection period, from 2.0 tcf in 2005 to 1.1 tcf in 2030.

6.1.2 Natural Gas Production in the Lower 48 Outer Continental Shelf

For the AEO2007 reference case, an OCS access case was prepared to examine the potential impacts of the lifting of Federal restrictions on access to the OCS in the Pacific, the Atlantic, and the eastern Gulf of Mexico. Currently, except for a relatively small tract in the eastern Gulf, resources in those areas are legally off limits to exploration and development. Mean estimates indicate that technically recoverable resources currently off limits in the lower 48 OCS total 18 billion barrels of crude oil and 77 tcf of natural gas as illustrated in Figure 6-1.

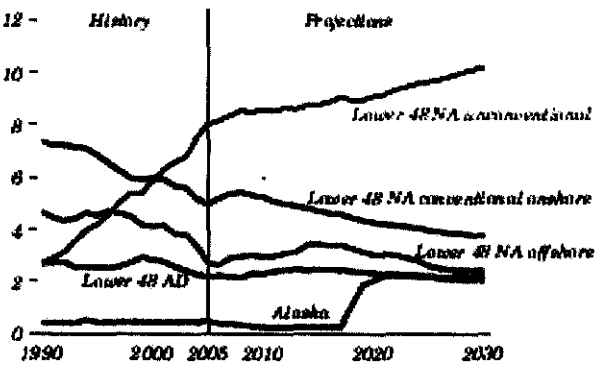


Figure 6-1
Forecasted Natural Gas Production by Source
(Source: www.eia.doe.gov)

Although existing moratoria on leasing in the OCS will expire in 2012, the AEO2007 reference case assumes that they will be reinstated, as they have in the past. Current restrictions are therefore assumed to prevail for the remainder of the projection period, with no exploration or development allowed in areas currently unavailable to leasing. The OCS access case assumes that the current moratoria will not be reinstated, and that exploration and development of resources in those areas will begin in 2012.

Assumptions about exploration, development, and production of economical fields (drilling schedules, costs, platform selection, reserves-to-production ratios, etc.) in the OCS access case are based on data for fields in the western Gulf of Mexico that are of similar water depth and size. Exploration and development on the OCS in the Pacific, the Atlantic, and the eastern Gulf are assumed to proceed at rates similar to those seen in the early development of the Gulf region. In addition, it is assumed that local infrastructure issues and other potential non-Federal impediments will be resolved after Federal access restrictions have been lifted. With these assumptions, technically recoverable undiscovered resources in the lower 48 OCS increase to 59 billion barrels of oil and

288 tcf of natural gas as compared with the reference case levels of 41 billion barrels and 210 tcf. As described below, Figure 6-2 illustrates the mix of OCS areas that is currently available and unavailable for leasing and development.

OCS areas	*Crude oil (billion barrels)*	*Natural gas (trillion cubic feet)*
Available for leasing and development		
Eastern Gulf of Mexico	*2.27*	*10.14*
Central Gulf of Mexico	*22.67*	*113.61*
Western Gulf of Mexico	*15.98*	*86.62*
Total available	***40.92***	***210.37***
Unavailable for leasing and development		
Washington-Oregon	*0.40*	*2.28*
Northern California	*2.08*	*3.58*
Central California	*2.31*	*2.41*
Southern California	*5.58*	*9.75*
Eastern Gulf of Mexico	*3.98*	*22.16*
Atlantic	*3.82*	*36.99*
Total unavailable	***18.17***	***77.17***
Total Lower 48 OCS	***59.09***	***287.54***

Figure 6-2
Technically Recoverable Undiscovered Gas in the Lower 48 OCS
(Source: www.eia.dov.gov)

Potential sources of natural gas for Cane Island 4 include the addition of natural gas recovered from available leasing and development areas. Additional sources of natural gas located in the lower 48 OCS present reasonable insurance of adequate availability of natural gas for Cane Island 4.

6.2 Liquefied Natural Gas (LNG)

LNG is natural gas that has been cooled to -260°F at atmospheric pressure, the point at which natural gas condenses to a liquid. When natural gas is converted to a liquid (LNG), its volume is reduced by a ratio of 600 to 1, allowing considerably more natural gas to be stored and shipped in its liquid form. The LNG is stored in double-walled tanks at atmospheric pressure and shipped aboard specially designed LNG storage vessels.

Upon the vessel's arrival at an LNG receiving facility, the LNG is pumped onshore in its liquid state and then stored in permanent double-walled tanks, or it is heated, vaporized, and regulated for temperature and pressure, and delivered as natural

gas into a pipeline network. The former method provides the greatest flexibility where the LNG is stored until needed, acting similar in nature to deliveries from natural gas storage. In the latter instance, the gas must be received and used as a supplemental base load supply.

With U.S. natural gas production remaining relatively constant, imports of natural gas are projected to rise to meet an increasing share of domestic consumption. Most of the expected growth in U.S. natural gas imports is in the form of LNG. The LNG market is expected to be tight until 2012, because of supply constraints at a number of liquefaction facilities, delays in the completion of new liquefaction projects, and rapid growth in global LNG demand. The expansion of LNG supplies after 2012 will increase the opportunity for Cane Island 4 to receive natural gas from LNG terminals located in the southeastern United States.

6.2.1 Liquefied Natural Gas in the North America

The United States is the fourth leading importer of LNG in the world. Japan, South Korea, and Spain are the three leading importers of LNG. In 2006, the United States LNG imports totaled 583 Bcf and these imports were sourced from four countries: Trinidad and Tobago, Egypt, Nigeria, and Algeria. By the end of 2006, liquefaction capacity in the Atlantic Basin was about 3,129 Bcf. The increase in the Atlantic Basin's liquefaction capacity is due to expansions in Egypt, Trinidad and Tobago, and Nigeria. As indicated in Section 7.0, Fuel Emissions Allowance Price Projections, natural gas consumption in the United States in expected to increase significantly and most of the expected growth in natural gas consumption is expected to be in the form of LNG. It is anticipated that LNG receiving terminal capacity will increase from 1.4 Tcf in 2005 to 6.5 tcf in 2030.

As illustrated in Figure 6-3, Trinidad and Tobago, Egypt, Nigeria, and Algeria exported 389 Bcf, 120 Bcf, 57 Bcf, and 17 Bcf respectively of LNG to the United States.

Currently, the United States maintains four onshore LNG terminals: Distrigas Facility in Everett, Massachusetts; Dominion Cove Point LNG in Lusby, Maryland; Southern LNG in Elba Island, Georgia; and Trunkline LNG in Lake Charles, Louisiana. The United States also has one off-shore LNG terminal, The Gulf Gateway Energy Bridge. These existing energy terminals are shown in Figure 6-4. The Distrigas facility is owned by Suez, North America and receives the largest volume of any onshore terminal in the United States at 176 Bcf. The daily capacity of the Distrigas facility is 725 MMcf. By comparison, the Dominion Cove LNG facility received 117 Bcf in 2006 and plans are in place to expand the regasification capability of the facility to 657 Bcf by the fall of 2008. StatoilHydro, Shell, and BP currently share the capacity rights to the Dominion Cove LNG facility.

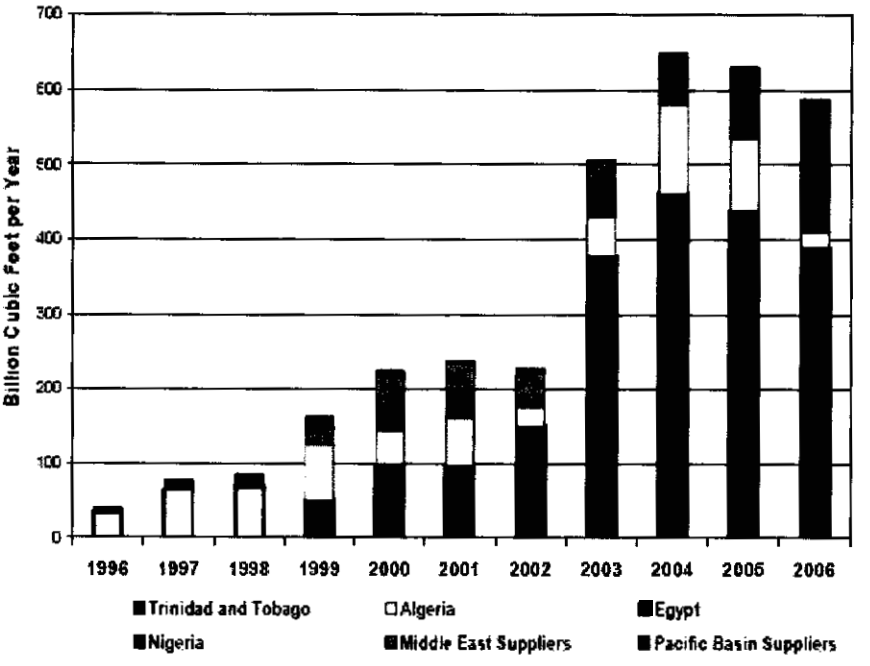


Figure 6-3
Top LNG Exporters to the United States
(Source: www.eia.doe.gov)

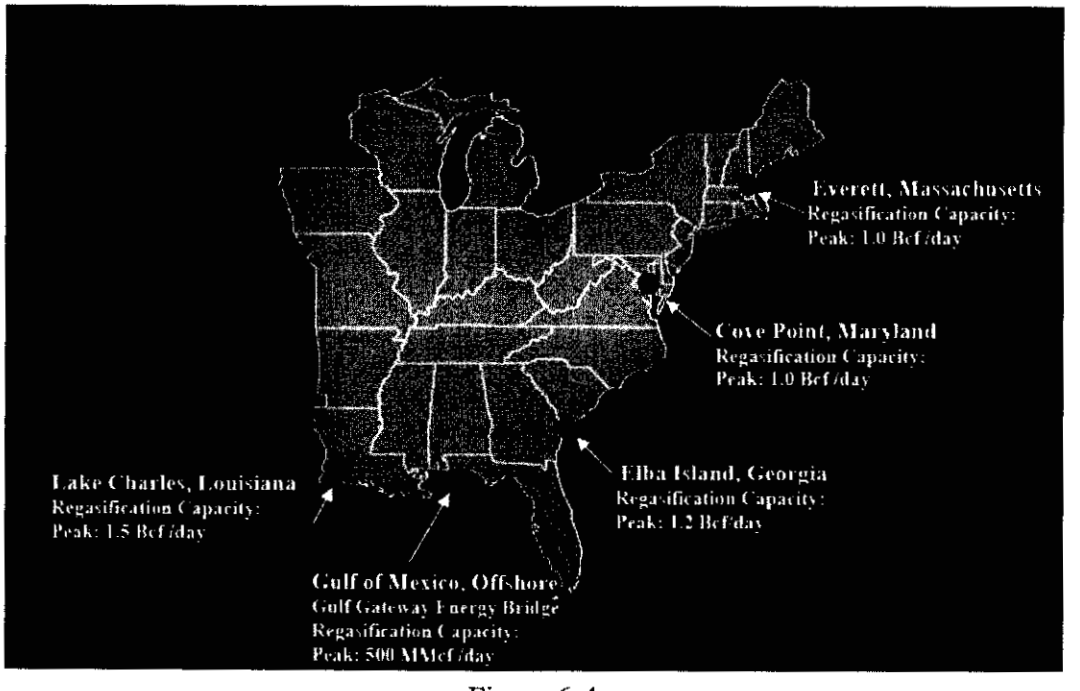


Figure 6-4
Current U.S LNG Import Terminals
(Source: www.eia.doe.gov)

Southern LNG and Trunkline LNG received 147 Bcf and 144 Bcf of LNG respectively in 2006. The United Kingdom based BG Group owns the capacity rights to the Southern and Trunkline LNG facilities. Both facilities have undergone recent expansions and plans are in place to further expand each facility. El Paso Corporation which owns Southern LNG and have formulated a plan to increase its regasification capacity from the current 1.2 Bcf/d to 2.1 Bcf/d by 2010 as well as constructing new pipeline connections to access new markets. The Southern Union Company owns Trunkline LNG which maintains a regasification capacity of 1.8 Bcf/d. Currently, the send out capacity of the Trunkline LNG facility is 0.3 Bcf/d, but plans are in place to increase the send out capacity to 2.1 Bcf/d by 2009.

6.2.2 *Existing LNG Importing Countries for North America*

The Atlantic LNG facility, located in Port Fortin, Trinidad and Tobago is the primary facility from which the United States receives LNG imports. In 2005, the liquefaction capacity of the Atlantic LNG facility was expanded to 720 Bcf. The expansion entailed the addition of a fourth operational train which is the single largest operational train in the world with the capacity to liquefy 240 Bcf of LNG. In May 1999, the initial imports from the Atlantic LNG facility destined for the United States were delivered to the Distrigas LNG facility in Everett, Massachusetts.

Algeria, which formerly was the largest exporter of LNG supply to the United States, exported a total 17 Bcf of LNG in 2006. This was a drastic reduction from the amount of LNG exported in 2005 of 97 Bcf.

Egypt began exporting LNG to the United States in 2005. During 2005, Egypt exported a total of 73 Bcf to the United States. In 2006, Egypt increased LNG exports to the United States by 47 Bcf or 64.8 percent to a total of 120 Bcf.

Nigeria increased LNG exports to the United States from 8 Bcf in 2005 to 57 Bcf in 2006 after increasing the liquefaction capacity on the Bonny Island facility.

6.2.2.1 Potential LNG Importing Countries for North America. A portion of the future growth in LNG consumption in the United States is anticipated to come from Equatorial Guinea, Norway, and the Middle East. Marathon Oil Corporation has begun operations of an LNG plant on Bioko Islam and deliveries to the United States were anticipated to start in 2007. The BG Group has contracted to market supplies from the one train facility which will be solely focused on the United States.

Additional supplies will arrive from Snohvit LNG project in Norway through a contract with StatoilHydro ASA. The Norwegian firm has contracted capacity for delivery to the Cove Point import terminal in Maryland. LNG deliveries to the terminal are scheduled to commence in 2008.

In the Middle East, Qatargas II is expected to begin operations in mid-2008. The liquefaction capacity of Qatargas II is 720 Bcf which will be solely marketed to markets within the Atlantic Basin.

New supplies are anticipated to come online in Yemen, Russia and Nigeria by early 2009.

6.2.2.2 Construction of New LNG Import Terminals in North America. The United States is expected to have adequate regasification capacity to meet domestic needs, with several existing LNG import terminals increasing capacity and new projects nearing completion. LNG import capacity was about 4.25 Bcf/d at the end of 2006 and about 5.3 Bcf/d at the end of 2007. It is projected that the regasified natural gas send out capacity of onshore facilities could grow to more than 10 Bcf/d by the middle of 2010, with about half of this send out capacity coming from new terminals.

The Freeport LNG terminal on Quintana Island, Texas is nearing completion and will mark the first new onshore terminal in the United States in more than 25 years. Operations are expected to begin in 2008, with deliverability of 1.5 Bcf/d. The terminal is owned by a partnership of Michael S. Smith and ConocoPhillips, Cheniere Energy, Dow Chemical, and Contango Oil and Gas companies. ConocoPhillips has contracted for 500 MMcf/d of the capacity until mid-2009 and 1 Bcf/d thereafter; Dow Chemical, 500 MMcf/d; and Mitsubishi Corp., 150 MMcf/d for 17 years starting in 2009. Freeport LNG has also received approval from the FERC to expand the terminal's regasification capacity to 4.0 Bcf/d, which would make it the largest regasification terminal in the United States.

Cheniere Energy, Incorporated, is nearing completion of its new Sabine Pass LNG terminal in Cameron Parish, Louisiana. That facility will have 2.6 Bcf/d of send out capacity. Total S.A. has reserved 1 Bcf/d of capacity for 20 years, while Chevron Corp. has reserved 700 MMcf/day for 20 years. As with the Freeport LNG terminal, operations are expected to begin in early 2008, and Cheniere Energy has received permission from FERC to expand the LNG terminal to 4.0 Bcf/d.

Sempra Energy's Cameron LNG facility on Lake Charles, Louisiana, is under construction with expected initial capacity of 1.5 Bcf/d and an estimated operation date of late 2008. Italy's Eni SpA has agreed to purchase 0.6 Bcf/d of capacity at the facility for 20 years, while Algeria's Sonantrach, Suez North America, and Merrill Lynch Commodities are nearing final capacity arrangements. While the first phase of construction is ongoing, Sempra has initiated regulatory applications for a second phase of construction that would increase regasification capacity to about 2.7 Bcf/d by 2010.

ExxonMobil has received approval from FERC and has begun construction of its Golden Pass project near Sabine Pass, Texas. In the first phase of operations, Golden Pass, majority owned by Qatar Petroleum, will have the capacity to deliver up to 1 Bcf/d into the pipeline grid. It will likely be employed for receiving LNG from Qatar starting in 2009. ExxonMobil has signed heads of agreement with Qatar for 2 Bcf/d of supply starting in 2009. However, clearly not all of this supply will be directed to the U.S. market.

Two offshore Massachusetts import facilities are being constructed that will provide natural gas to the New England market. Excelerate Energy owns one of the offshore facilities which is located in Massachusetts Bay about 13 miles off the Boston coastline. Northeast Gateway expects to receive its first deliveries in 2008. Additionally, Suez North America is close to starting construction of its Neptune LNG project, located in Federal waters 22 miles northeast of Boston and approximately 10 miles off the coast of Massachusetts' North Shore.

6.2.2.3 Gulf Coast LNG. LNG can be a viable alternative supply source to supplement the more traditional supply alternatives in North America. There are a number of LNG projects in the Gulf Coast area. Figure 6-5 (obtained from FNGA) illustrates the existing and proposed facilities.

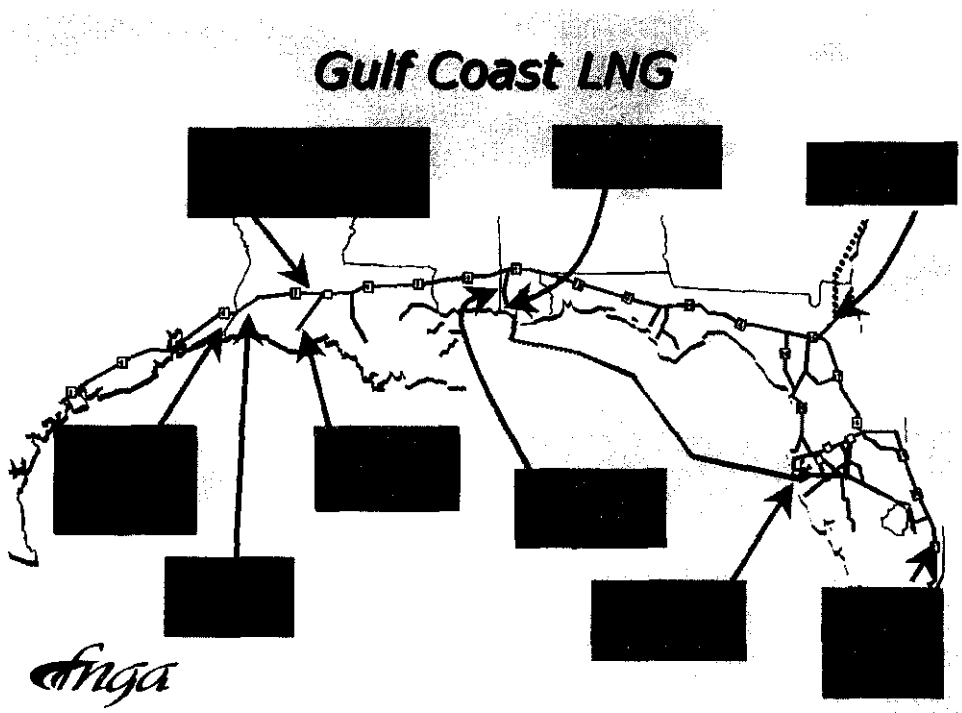


Figure 6-5
Existing & Proposed Gulf Cost LNG Projects
(Source: www.floridagas.org)

There are four viable options to supply Florida directly with LNG, recognizing the pipeline transportation limitations. These four options are: (1) Elba Island with deliveries to FGT via the Cypress pipeline; (2) Gulf LNG Clean Energy Project; (3) the Port Dolphin Project; and (4) the Calypso Project. The first two projects are onshore LNG storage facilities that either exist (Elba Island) or are under construction. The latter two are deep water port facilities that will gasify LNG onboard the delivering vessel. The Gulf LNG Clean Energy Project and the Dolphin Port Project are still obtaining the necessary permits and certifications. The following subsections discuss each of these projects.

6.2.2.3.1 Gulf LNG Clean Energy Project. The Gulf LNG Clean Energy Project is jointly owned. El Paso Corporation owns 50 percent of the facility. The remaining 50 percent is shared by The Crest Group, consisting of Houston-based investors, with a 30 percent ownership in the project, and Sonangol USA with 20 percent. Sonangol is the state-owned national oil company of Angola, responsible for the development of Angola's hydrocarbon resources.

The project received its Federal Energy Regulatory Commission (FERC) certificate in February 2007 and is currently under construction. The terminal includes the construction of two, 160,000 cubic meter storage tanks with a combined capacity of 6.6 billion cubic feet (Bcf); 10 vaporizers, providing a base send-out capacity of 1.3 Bcf/d and five miles of 36-inch pipeline. The pipeline will connect the terminal to Gulfstream, Destin Pipeline, FGT, and Transco. The terminal is expected to be placed into service in late 2011 at an estimated cost of $1.1 billion.

6.2.2.3.2 Elba Island. There is a planned expansion for the Elba Island LNG Terminal. Southern LNG plans to complete the expansion in two phases. Phase I of the project will add one 200,000 cubic meter storage tank which holds 1,250,000 barrels. The new tank will be complete by mid-year of 2010 and will add approximately 4.2 Bcf of LNG storage capacity to the terminal. Maximum send out capacity will be 0.405 Bcf/d. Phase I of the project will also include modifying the north and south docks to accommodate new larger vessels and to facilitate simultaneous unloading of two ships.

Phase II of the project will add an additional 200,000 cubic meter (1,250,000 barrel) storage tank. This tank will add approximately 4.2 Bcf storage capacity to the terminal in 2012 and increase send out by 0.495 Bcf/d. The liquefied natural gas for the expansion will be transported by ship from gas rich regions outside of the United States. Southern LNG's facilities at Elba Island will vaporize the LNG and inject the natural gas into Southern's existing pipeline. Figure 6-6 illustrates the relative proximity of Elba Island to the Cypress Pipeline.

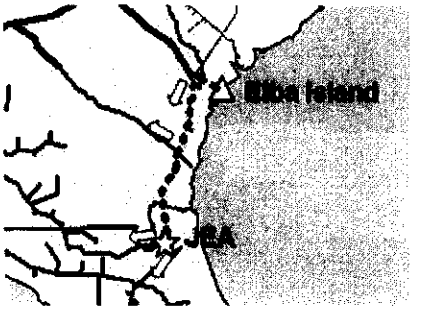


Figure 6-6
Cypress Pipeline
(Source: www.elpaso.com)

6.2.2.3.3 The Calypso System. Calypso LNG LLC (a subsidiary of SUEZ Energy International) is proposing the development of a submerged buoy system known as a "Deep Water Port" (DWP) located approximately 8 to 10 miles off the southeastern coast of Florida. The Calypso DWP will serve as an offshore delivery point for connection to specially built LNG tankers. The LNG tankers will vaporize stored LNG and send it through the buoy system into the FERC-permitted Calypso U.S. Pipeline, which will transport the natural gas onshore to deliver to the FGT system. When the offloading system is not in use, it resides approximately 120 feet under the ocean surface. The DWP will consist of two buoys approximately 2.6 miles apart. The DWP project will be located approximately 8 to 10 miles offshore from Port Everglades.

The Calypso Pipeline is planned to make landfall within Port Everglades and will connect with the existing FGT pipeline system approximately 6 miles inland. The project will be capable of delivering approximately 1 Bcf/d of natural gas directly into the Florida market.

The Maritime Administration (MARAD) and the Coast Guard announced in the Federal Register on November 2, 2007 the availability of the Draft Environmental Impact Statement (DEIS) for the Calypso LNG LLC, Calypso Natural Gas Deepwater Port (Calypso) license application. The application describes a project that would be located in the Federal waters of the Outer Continental Shelf in the OCS NG 17–06 (Bahamas) lease area, approximately 8 to 10 miles off the east coast of Florida to the northeast of Port Everglades, in a water depth of 800 to 950 feet. USCG and MARAD have 240 days from the date of the Notice of Application to hold one or more public license hearings in the adjacent coastal state of Florida. The Governor of Florida must approve, approve with conditions, or deny the DWPA license within 45 days of the last DWPA public hearing. If the Governor does not act within 45 days, approval will be conclusively presumed. Approval or denial of the license application by MARAD must occur not more than 90 days after the last public hearing.

The Environmental Resource Permit (ERP) was issued by the State of Florida to the original project owner (Tractebel) in April 2004. The Calypso Pipeline is one of the 21 US LNG projects approved by FERC.

6.2.2.3.4 Port Dolphin Energy. Port Dolphin Energy LLC, a wholly owned US subsidiary of the Norwegian based company Hoegh LNG AS, is proposing development of a submerged buoy system known as a "Deep Water Port" (DWP) The proposed project would consist of two submerged unloading and mooring buoys to receive an average of up to 800 million cubic feet per day of natural gas from LNG Shuttle and Regasification Vessels (SRVs), which are ocean going LNG vessels designed to regasify the LNG onboard and deliver natural gas to a subsea pipeline. The DWP would be connected to a 42 mile subsea pipeline that would bring the regasified natural gas from the offshore terminal to Port Manatee in Tampa Bay. The pipeline is planned to interconnect with Gulfstream and the facilities of TECO Energy, Inc. (TECO). The proposed offshore terminal would be located approximately 28 miles from the coast. Initial average daily throughput will be approximately 400 MMBtu/d of natural gas will have a capacity of 800 MMBtu/d of natural gas with peak delivery capacity of approximately 1.2 Bcf/d of natural gas.

Port Dolphin filed its DWPA with the USCG in March 2007 and expects the approval process for the Deepwater Port License and associated permits will take approximately 18 months. Construction of the proposed project would consist of two phases with operations of Port Dolphin beginning in the second quarter of 2011.

6.3 Natural Gas Reserves

The United States had 211,085 billion cubic feet of dry natural gas proved reserves as of December 31, 2006, the highest level since 1976. Proved reserves of natural gas increased by 3 percent from 2005 to 2006.

Texas led the nation in natural gas reserves additions in 2006 with a 9 percent increase in dry gas proved reserves due to rapid development of Barnett Shale reservoirs in the Newark East Field. Advances in horizontal drilling and hydraulic fracturing technology and relatively high natural gas prices supported this development. Alaska and Utah were second and third for dry natural gas proved reserves additions in 2006. Total U.S. reserves additions replaced 136 percent of 2006 dry gas production as illustrated in Figure 6-7.

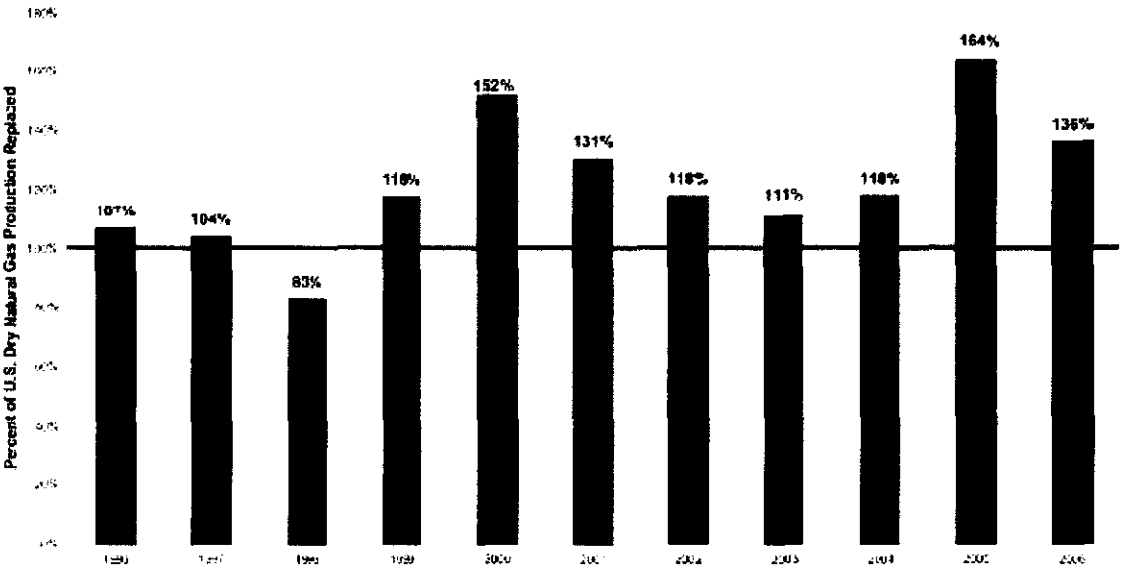


Figure 6-7
Replacement of Dry Natural Gas Productions by Reserve Additions 1996 - 2006
(Source: www.eia.dov.gov)

The proved reserves by State are shown on the map in Figure 6-8. Eight areas accounted for 81 percent of the Nation's dry natural gas proved reserves which amounts to about 171,000 bcf. The highest concentration of natural gas reserves clusters around the Gulf Coast states. Also, highest potential production of natural gas clusters around the Gulf Coast states. Strong potential exist in transporting natural gas reserves on the Transco Pipeline into the FRCC region making the necessary connection onto the Gulfstream Pipeline. Figure 6-8 illustrates the proved natural gas reserves in North America.

6.3.1 Natural Gas Demand

As established in the AEO2007 reference case, current natural gas prices are sufficiently high to reduce growth in consumption. The combination of increased natural gas supply, slower growth in demand, and the technological improvement in the development of other fuel resources leads to a decline in natural gas prices through 2013 as forecasted in the AEO2007 reference case. After 2013, wellhead natural gas prices increase largely as a result of rising costs, as technically recoverable U.S. natural gas resources decline from the current level. Figure 6-9 illustrates technically recoverable U.S natural gas resources as of January 1, 2005 in tcf.

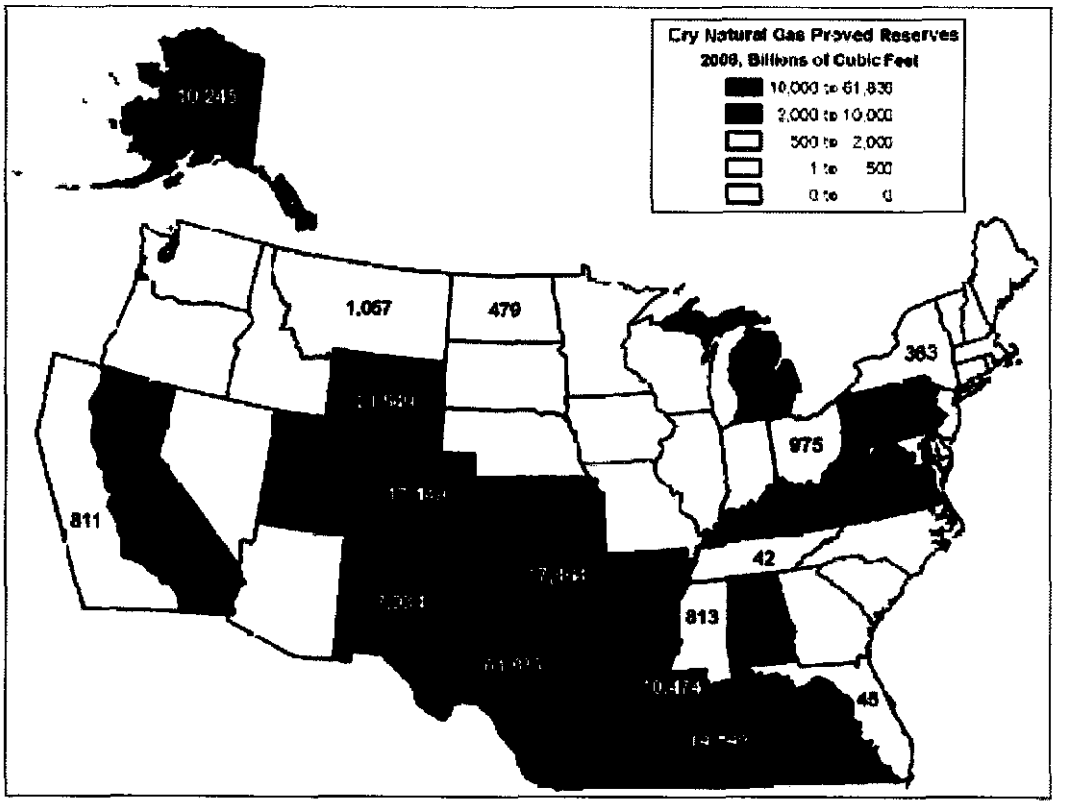


Figure 6-8
Dry Natural Gas Proved Reserves
(Source: www.eia.dov.gov)

Proved	Unproved	Total
192.5	1,148.5	1,341.0

Figure 6-9
Technically Recoverable U.S. Natural Gas Resources
(Source: www.eia.doe.gov)

Total natural gas consumption in the United States is projected to increase from 22.0 tcf in 2005 to 26.1 tcf in 2030 in the AEO2007 reference case. As outlined in the AEO2007 reference case, a portion of natural gas consumption will utilize LNG as the primary source of fuel. Much of the growth is expected before 2020, with demand for natural gas in the electric power sector growing from 5.8 tcf in 2005 to a peak of 7.2 tcf. Natural gas use in the electric power sector is projected to decline after 2020, to 5.9 tcf in 2030, as new coal-fired generating capacity displaces natural-gas-fired generation. Much of the projected decline in natural gas consumption for electricity generation results from higher delivered prices for natural gas in the reference case projection after 2020.

Continued growth in residential, commercial, and industrial consumption of natural gas is roughly offset by the projected decline in natural gas demand for electricity generation. As a result, overall natural gas consumption is almost flat between 2020 and 2030 in the AEO2007 reference case, and the natural gas share of total projected energy consumption drops from 23 percent in 2005 to 20 percent in 2030.

As forecast in the AEO2007 reference case, the growth in total U.S. generation fuel by natural gas and the reduction in natural gas consumption due to additional sources of fuel and fuel development technologies will create an unmatched capacity to demand relationship over the forecast period. The unmatched capacity to demand relationship will create additional sources of available natural gas that can be available to supply Cane Island 4.

6.4 Natural Gas Pipeline and Storage

Natural gas storage facilities are being developed along the Gulf Coast in numerous locations. The southeastern states of the United States account for approximately 38,127 of pipeline mileage with the State of Florida accounting for 4,746 miles of pipeline. As illustrated in Figure 6-10, Florida's total pipeline capacity is 3,600 MMcf/d based on the total capacity of all the pipelines that serve the Florida market. The total Florida pipeline capacity is served by four companies: Florida Gas Transmission, GulfSouth Pipeline, Gulfstream NG System, and Southern Natural Gas. These four pipelines will provide adequate natural gas transportation capacity along with the existing and proposed storage facilities will provide adequate transportation and storage capacity for the Florida market.

6.4.1 Natural Gas Storage Facilities in Florida

There are three facilities that can provide immediate benefit to the Florida market due to their respective locations. Figure 6-11 provides an overview of many of these developments (provided by FNGA).

Line	Description	Region From	Region To	State From	State To	County From	County To	Capacity [1] MMcf/d
1	Florida Gas Trans Co	Southeast	Southeast	AL	FL	Escambia	Santa Rosa	2,224
2	Gulf South Pipeline Co	Southeast	Southeast	AL	FL	Baldwin	Escambia	125
3	Gulf South Pipeline Co	Southeast	Southeast	AL	FL	Baldwin	Escambia	45
4	Gulf South Pipeline Co	Southeast	Southeast	AL	FL	Escambia	Escambia	20
5	Gulfstream NG System	Southeast	Southeast	AL	FL	Mobile	Manatee	1,130
6	Southern Natural Gas Co	Southeast	Southeast	GA	FL	Decatur	Gadsden	9
7	Southern Natural Gas Co	Southeast	Southeast	GA	FL	Lowndes	Hamilton	47
8	**Total**							**3,600**

Note:
1. The capacity denotes the pipeline capacity for the State of Florida at the end of 2006.

Figure 6-10
Florida Pipeline Capacity
(Source: www.eia.doe.gov)

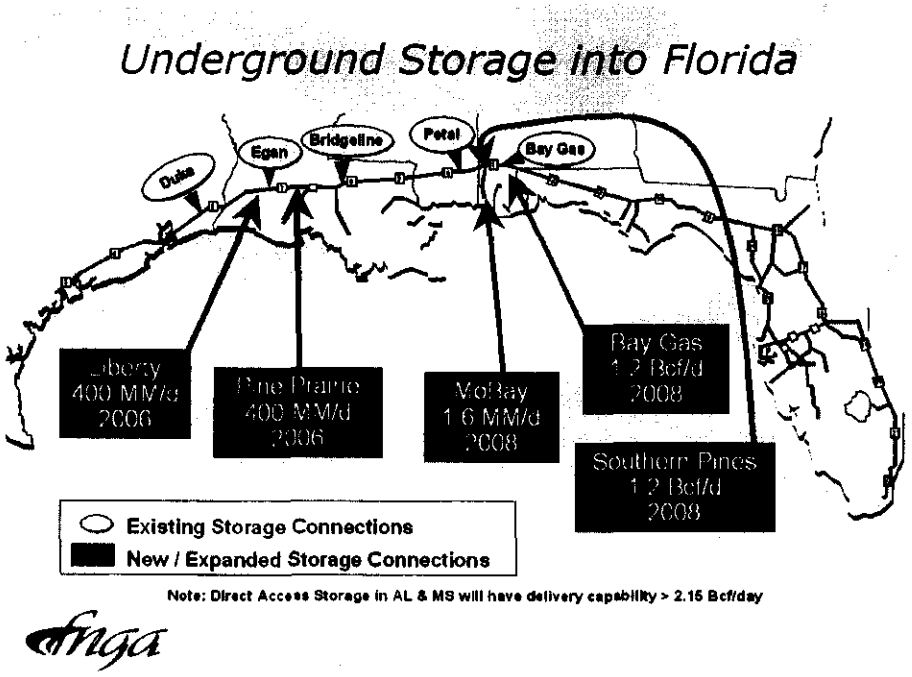


Figure 6-11
Underground Storage into Florida
(Source: www.floridagas.org)

6.4.1.1 Southern Pines Energy Center. Southern Pines Energy Center is being developed as a FERC-regulated natural gas storage facility. The project site has the capability to develop up to five 8 Bcf caverns for a total working gas capacity of 40 Bcf. Currently the project is constructing a 16.0 Bcf multi-cycle natural gas storage facility consisting of two underground storage caverns, each capable of storing up to 8.0 Bcf each. The first cavern entered commercial operation May 1, 2008 and the second is scheduled for commercial operation later in the year. A third cavern is planned for 2008 with commercial operation in 2010.

The natural gas storage facilities will include:

- Three salt caverns capable of storing 24 Bcf in an underground salt-dome (with the capability of constructing two additional caverns for a total of 5 caverns and 40.0 Bcf of storage capacity).
- Above ground facilities with 48,000 horsepower of compression for the three storage caverns and with 1.6 Bcf/d of maximum withdrawal capability and 0.8 Bcf/d of maximum injection capability. This configuration enables Southern Pines to cycle its working gas capacity a maximum of 12 times per year, thus providing its customers with the ultimate flexibility to quickly balance operational flows and meet peaking demands.
- Southern Pines will initially have direct interconnects to three existing interstate pipelines, Destin Pipeline Company ("Destin"), Florida Gas Transmission Company ("FGT") and Transcontinental Gas Pipe Line Corporation ("Transco"). An interconnection with the Southeast Supply Header is scheduled for service in second quarter 2008 as that pipeline is constructed.

FMPA will have 1 Bcf of capacity in this facility by the time that Cane Island 4 is constructed. This storage will provide significant capabilities for daily operations and provide supply back-up during times of supply interruptions. Figure 6-12 illustrates a map of the Southern Pines Energy Center.

6.4.1.2 MoBay Storage Hub LLC. MoBay Storage Hub LLC will provide high-deliverability, multi-cycle (HDMC) gas storage services to the Southeast market. Located at the confluence of major market and supply area pipeline systems, MoBay would initially connect with four major interstate pipelines systems serving the Southeast and Northeast markets. Currently, the combined pipeline take-away capacity at MoBay is 6.9 Bcf/d to the east and 3.9 Bcf/d to the west. MoBay would be the most southeasterly HDMC storage facility in the United States and the only storage facility directly connected to the Gulfstream Natural Gas System. The proposed MoBay

compressor station will be located directly adjacent to Gulfstream Station 410 in Mobile County, Alabama. Working gas capacity will be 50 Bcf with maximum injection and withdrawal capability of 1 Bcf per day.

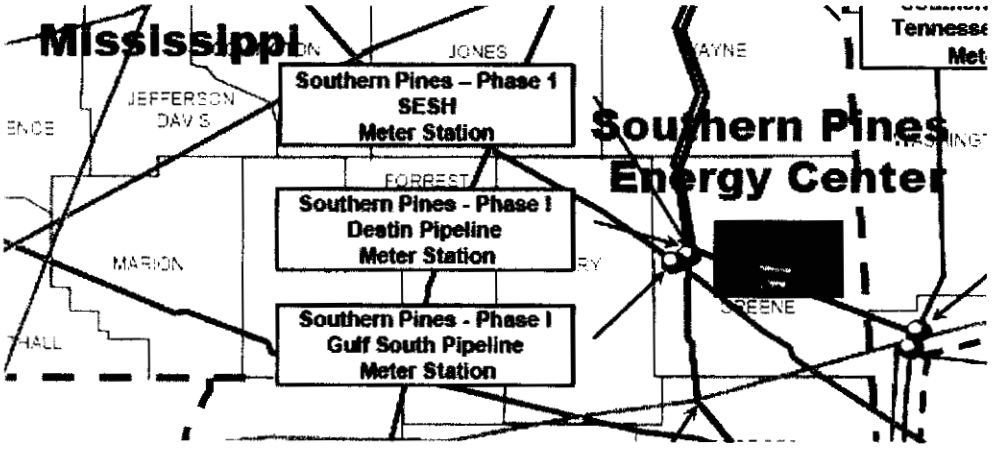


Figure 6-12
Southern Pines Energy Center
(Source: www.sgr-holdings.com)

Figure 6-13 illustrates the relative proximity of the Mobay Storage Hub to the relative gas pipeline interconnections.

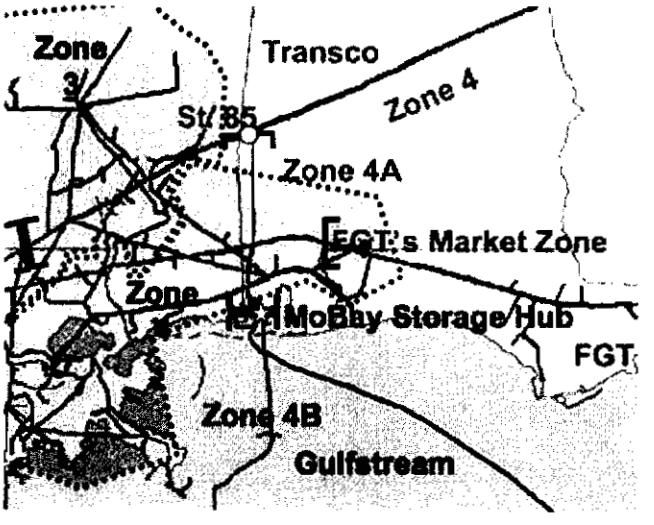


Figure 6-13
MoBay Storage Hub
(Source: www.falcongasstorage.com)

6.4.1.3 Bay Gas Storage. Bay Gas Storage is owned by EnergySouth Midstream, Inc. is based in Houston, Texas. Bay Gas currently operates two high-deliverability natural gas salt dome storage caverns with a combined total working gas capacity of 6.0 Bcf. Total injection capacity at the facility is 200 MMcf/d and withdrawal capacity is 610 MMcf/d.

A third storage cavern is currently under development and is expected to be operational by the spring of 2008 and will add approximately 5.0 Bcf of working gas capacity. Injection capacity at cavern three will be 250 MMcf/d and withdrawal capacity will be 600 MMcf/d. Total working gas capacity will increase from 6.0 Bcf to 11.0 Bcf upon completion of the third cavern. Figure 6-14 illustrates a map of the Bay Gas Storage Facility.

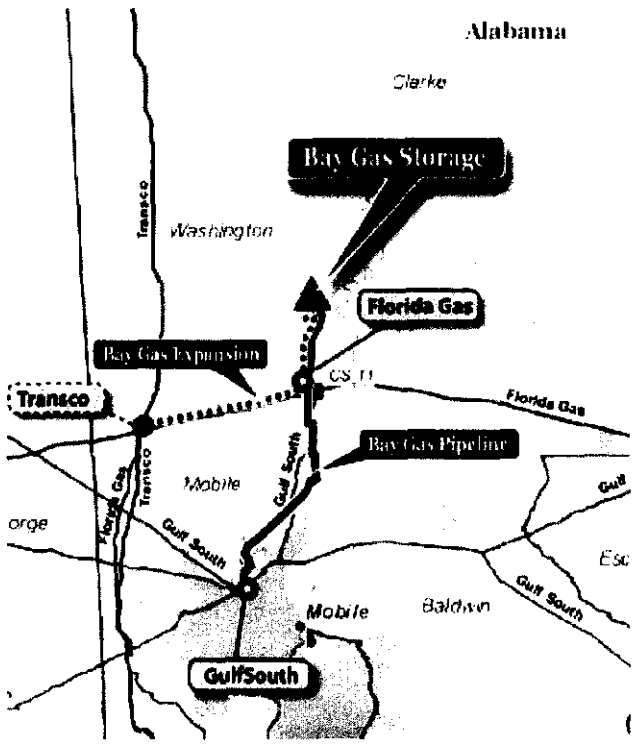


Figure 6-14
Bay Gas Storage Facility
(Source: www.esmidstream.com)

6.5 Southeast Supply Header

The Southeast Supply Header, LLC (SESH) is a joint venture between subsidiaries of CenterPoint Energy, Inc. and Spectra Energy. The 270 mile, 36 inch and 42 inch diameter pipeline has an estimated capacity of 1 Bcf/d. The pipeline will extend from the Perryville Hub in northeastern Louisiana to Gulfstream in southern Mobile County, Alabama and will have two interconnects with FGT, the combination of which will have a capacity of over 1 Bcf/d.

SESH will link the onshore natural gas supply basins of east Texas and northern Louisiana to Southeast markets now predominantly served by offshore natural gas supplies from the Gulf of Mexico. This pipeline will give customers an important alternative to offshore supply, which can be vulnerable to weather-related disruptions. The pipeline is scheduled for first deliveries in August, 2008. Figure 6-15 illustrates a map of the Southeast Supply Header route.

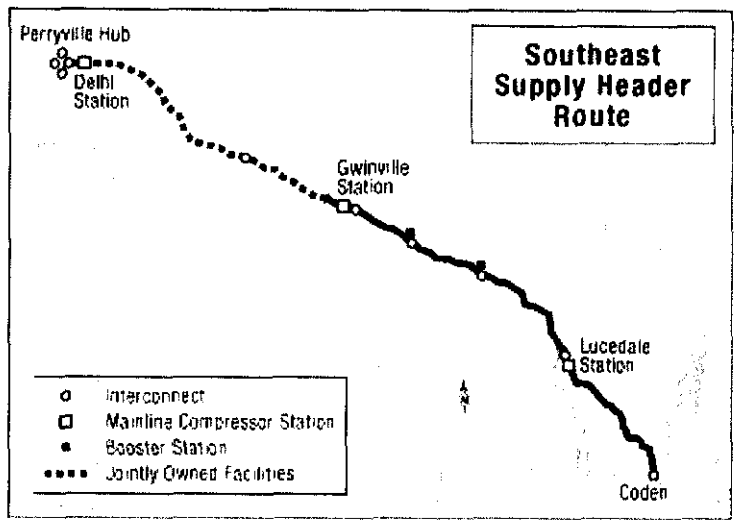


Figure 6-15
Southeast Supply Header Route Pipeline

6.5.1 *Floridian Natural Gas Storage Company*

The Floridian Natural Gas Storage Company LLC (FGS) facility is expected to be located in an industrial area near Indiantown in Martin County, FL. The FGS facility will ultimately consist of two above-ground liquid natural gas storage tanks each capable of storing up to 4 Bcf of natural gas, refrigeration compressors to cool the gas, and re-gasification equipment. Natural gas will be delivered to and from FGS using both the FGT and Gulfstream natural gas pipeline systems. FGS is expected to begin commercial operation in mid-2011.

FGS will be regulated by the FERC. In October 2007, FGS filed an abbreviated application pursuant to section 7(c) of the Natural Gas Act (NGA) and Parts 157 and 284 of FERC's regulations for a certificate of public convenience and necessity to construct and operate the FGS project; a blanket certificate to perform certain routine activities and operations; and a blanket certificate to provide open access storage services. The proposed project is currently under FERC review with a target decision date of October 23, 2008.

The addition of down stream storage facilities will effectively increase the capacities of the FGT/Gulfstream systems.

6.6 Summary of Natural Gas Availability

As discussed in the previous sections, while conventional production in the lower 48 states is projected to decline slightly, the natural gas industry has many alternatives available to ensure a reliable supply of natural gas for Cane Island 4. These include production in the outer continental shelf, production in Alaska, and delivery via pipeline to the lower 48 states. While the Alaskan gas may not be delivered directly to Cane Island 4, it will displace the use of other gas, allowing that gas to be delivered to Cane Island. In addition to domestic production, there is a robust LNG marketing developing along with associated delivery and storage systems. The United States has sufficient reserves to serve Cane Island 4 and these reserves are consistently being replaced as the gas has been consumed.

Natural gas storage facilities are being constructed which will allow for better management of gas volumes and increases in surety of supply. In addition, projects are under way to better provide for gathering of gas to the pipelines that serve Cane Island.

In total, ample natural gas is available to ensure a reliable supply for Cane Island 4.

7.0 Fuel and Emissions Allowance Price Projections

This section discusses the methodology used to develop projections for the prices of natural gas, distillate and residual fuel oils, and coal specific to the Florida Reliability Coordinating Council (FRCC) region that are considered in this Application. In addition to the reference case price projections, high and low price projections have been developed as well. The analyses presented throughout this Application also consider projections of emissions allowance prices. Development of these emissions allowance price projections are presented in this section as well.

7.1 Importance of Fully Integrated Fuel and Emissions Allowance Price Projections

The fuel and emissions allowance price projections considered throughout this Application (whether for the reference case, high case, low case, or the case in which existing and potential new emissions, such as CO_2, are treated as regulated emissions) represent fully integrated forecasts. That is, fuel price, supply, and demand are considered in tandem with potential costs associated with regulation of various emissions, along with numerous other market influences to develop fully integrated projections of fuel and emissions allowance prices. This is important for all scenarios considered, but especially so when considering the potential impacts associated with regulation of CO_2.

Regulations of emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x), and mercury (Hg) are reflected in all of the fuel price projections considered throughout this Application. While there is currently no state or federal regulation of CO_2 emissions, several bills to regulate emissions of CO_2 (and other greenhouse gases) have been proposed to the 110th US Congress. As such, this Application considers potential regulation of CO_2 emissions as outlined in Sections 7.7 and 7.8.

7.2 Description of 2007 US Energy Information Administration Annual Energy Outlook Reference Case

The fuel price projections for natural gas, fuel oil, and coal used in this Application were developed based on those included in the US Energy Information Administration (EIA) Annual Energy Outlook 2007 (AEO2007). The AEO2007 presents projections of energy supply, demand, and prices through the year 2030. The projections presented within the AEO2007 are based on results from the EIA's National Energy Modeling System (NEMS). NEMS is a computer-based, energy-economy modeling system of US energy markets and projects the production, imports, conversion, consumption, and prices of energy, subject to a variety of assumptions related to

macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, technology characteristics, and demographics. The discussion of the fuel price projections presented within this section is intended to be an overview of the AEO2007 and, therefore, focuses on the more salient aspects of the AEO2007 and elaborates on relevant conclusions and projections. The AEO2007 can be found on the EIA website at http://www.eia.doe.gov/oiaf/archive/aeo07, while documentation related to the EIA's NEMS program is located at http://tonto.eia.doe.gov/reports/reports_kindD.asp?type=model%20documentation.

7.2.1 Consideration of State and Federal Legislation and Regulations in AEO2007

Analyses developed by the EIA are required to be policy neutral. Therefore, the projections in the AEO2007 are based on federal and state laws and regulations in effect on or before October 31, 2006 (with few exceptions). As stated in the AEO2007, the potential impacts of pending or proposed legislation, regulations, and standards – or of sections of legislation that have been enacted, but that require implementing regulations or appropriation of funds that are not provided or specified in the legislation itself – are not reflected in the projections.

The AEO2007 does consider potential impacts of both the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR). The CAIR and CAMR were promulgated by the US Environmental Protection Agency (EPA) in March 2005 and published in the *Federal Register* as final rules in May 2005. CAIR will limit emissions of SO_2 and NO_x from power plants in the United States, while CAMR will limit emissions of Hg from power plants in the United States. Both the CAIR and CAMR are represented as regional cap-and-trade programs in AEO2007, as the document was developed before final decisions were made regarding the structure of state programs and participation in regional trading programs related to CAIR and CAMR.

7.3 AEO2007 Reference Case FRCC Natural Gas, Fuel Oil, and Coal Price Projections

The AEO2007 Reference Case forecast prices for natural gas and fuel oil delivered to the FRCC region are presented in Table 7-1[1]. Forecasts of prices for low sulfur Central Appalachian coal delivered to the Georgia/Florida region are presented in Table 7-2[2]. The fuel price projections shown in Tables 7-1 and 7-2 are presented in constant 2005 dollars per million British Thermal Units (MBtu). For the economic analysis presented in Section 20.0 of this Application, the fuel price projections were converted from those values shown in Tables 7-1 and 7-2 to nominal dollars per MBtu by applying the 2.3 percent general inflation rate.

The natural gas price projections presented in Table 7-1 represent the AEO2007 projections for natural gas delivered to the FRCC region and do not include any usage charges or any costs for firm or interruptible natural gas transportation. Discussion of how such costs were considered and factored into the economic analysis is presented in Section 19.3 of this Application.

Table 7-2 only presents forecast prices for coal delivered to the Georgia/Florida region from the Central Appalachia coal production region. Although the EIA provided forecast prices for coals from other production regions, this Application only considers coal delivered from Central Appalachia. The analyses presented throughout this Application assumes that low sulfur Central Appalachian coal will continue to be burned in Stanton Energy Center Units 1 and 2, which FMPA receives capacity from as described in Section 3.0 of this Application. These are the only solid fuel generating units (either existing or considered for capacity additions) evaluated in this Application.

[1] Regional fuel price projections, such as those shown in Table 7-1 for FRCC, are not included in the AEO2007 report itself, but are available on the EIA Web site as Supplemental Tables (http://www.eia.doe.gov/oiaf/aeo/supplement/index.html). The FRCC fuel price projections corresponding to the AEO2007, from which the data in Table 7-1 were extracted, are presented in Supplemental Table 69.
[2] Supplemental Table 69 to the AEO2007, referenced previously, only presents forecasts of prices for coal delivered to the FRCC region on a composite basis (i.e. a single coal price forecast, with no differentiation between coal type/production region). EIA was able to provide forecast prices for coal delivered to the Georgia/Florida region from various coal production regions upon request. These projections are factored into the overall modeling and analysis used to generate the coal price projection shown in Supplemental Table 69 to the AEO2007.

Table 7-1
Annual Energy Outlook 2007 Reference Case Price Projections
Forecast of Natural Gas and Fuel Oil Delivered to the
Florida Reliability Coordinating Council Boundary[1]

Year	Natural Gas (2005 $/MBtu) [2]	Distillate Fuel Oil (2005 $/MBtu) [3]	Residual Fuel Oil (2005 $/MBtu)
2007	7.65	16.12	8.48
2008	7.25	13.76	7.90
2009	6.69	12.67	7.26
2010	6.40	11.73	6.77
2011	5.92	10.91	6.39
2012	5.78	10.26	6.04
2013	5.64	9.48	5.87
2014	5.67	9.39	5.70
2015	5.61	9.45	5.78
2016	5.77	9.50	5.77
2017	5.96	9.67	5.89
2018	5.97	9.77	5.93
2019	5.98	9.95	6.10
2020	6.06	10.04	6.18
2021	6.02	10.16	6.30
2022	6.13	10.31	6.42
2023	6.22	10.28	6.35
2024	6.38	10.44	6.49
2025	6.37	10.48	6.52
2026	6.40	10.54	6.61
2027	6.49	10.72	6.65
2028	6.59	10.81	6.69
2029	6.63	10.97	6.80
2030	6.62	11.04	6.85

[1] Based on data presented in Supplemental Table 69 to the AEO2007 Reference Case.
[2] Natural gas price projections do not include usage charges or firm or interruptible transportation charges within the state. These costs are accounted for in the economic analysis as discussed in Section 19.0 of this Application.
[3] Distillate fuel oil price projections reflect the "nonroad, locomotive, and marine" (NRLM) diesel regulation finalized in May 2004, which requires sulfur content for all NRLM diesel fuel produced by refiners to be reduced to 500 parts per million (ppm) starting in mid-2007. NRLM also establishes a new ultra-low sulfur diesel (ULSD) limit of 15 ppm for nonroad diesel by mid-2010.

Table 7-2
Annual Energy Outlook 2007 Reference Case Price Projections
Forecast of Low Sulfur Central Appalachian Coal Delivered to the Georgia/Florida Region[1]

Year	Low Sulfur Central Appalachian[2] (0.54 lb S/MBtu) (2005 $/MBtu)
2007	2.89
2008	2.88
2009	2.88
2010	2.93
2011	2.96
2012	2.88
2013	2.88
2014	2.90
2015	2.87
2016	2.87
2017	2.84
2018	2.75
2019	2.69
2020	2.68
2021	2.66
2022	2.70
2023	2.70
2024	2.70
2025	2.69
2026	2.67
2027	2.66
2028	2.66
2029	2.66
2030	2.67

[1] Based on data received directly from the EIA.
[2] EIA price projections for Central Appalachian coal delivered to the Georgia/Florida region only extend through 2017, as the AEO2007 Reference Case assumes production from the Eastern Interior region, as well as imports, will contribute to the decline in Appalachia's share of the market east of the Mississippi. Beyond 2017, prices were developed on the basis of minemouth projections from the AEO2007 Reference Case and the assumption that transportation costs will remain constant in 2005 dollars.

7.4 AEO2007 High and Low Price Case Natural Gas, Fuel Oil, and Coal Price Projections

The AEO2007 includes various cases in addition to the Reference Case. Each of these cases incorporates various changes to the reference case assumptions. Of the various cases considered by the EIA as part of the AEO2007, two cases are considered in this Application in addition to the Reference Case – the High Price Case and the Low Price Case. Both the High Price Case and the Low Price Case rely on assumptions consistent with the Reference Case, with the exception of assumptions related to crude oil and natural gas resources. The High Price Case reflects more pessimistic assumptions related to these resources, while the Low Price Case reflects more optimistic assumptions. Both the High Price and Low Price Cases are fully integrated NEMS simulations, consistent with the Reference Case.

The natural gas, fuel oil, and coal price projections corresponding to the AEO2007 High Price Case are presented in Table 7-3. For comparison purposes, the AEO2007 Reference Case price projections for natural gas, fuel oil, and coal are also presented in Table 7-3. Figures 7-1 through 7-4 present graphical comparisons of the High Price Case and Reference Case price projections shown in Table 7-3.

The natural gas, fuel oil, and coal price projections corresponding to the AEO2007 Low Price Case are presented in Table 7-4. For comparison purposes, the AEO2007 Reference Case price projections for natural gas, fuel oil, and coal are also presented in Table 7-4. Figures 7-5 through 7-8 present graphical comparisons of the Low Price Case and Reference Case price projections shown in Table 7-4.

The price projections in Tables 7-3 and 7-4 (and corresponding Figures 7-1 through 7-8) are not specific to the FRCC region. The following section discusses the methodology used to develop high and low fuel price projections specific to FRCC.

Table 7-3
Natural Gas, Fuel Oil, and Coal Price Projections
AEO2007 High Price Case and AEO2007 Reference Case

Year	Natural Gas - Henry Hub (2005 $/MBtu)		Fuel Oil - Electric Power (2005 cents/gallon)				Coal - Average Minemouth (2005 $/MBtu)	
			Distillate		Residual			
	High Price Case	Reference Case	High Price Case	Reference Case	High Price Case	Reference Case	High Price Case	Reference Case
2007	7.31	7.23	199.97	197.82	109.52	107.69	1.18	1.18
2008	7.52	7.17	195.84	190.97	114.25	109.20	1.17	1.17
2009	7.17	6.60	190.79	176.19	114.29	104.67	1.17	1.16
2010	6.91	6.28	188.46	162.34	113.69	98.51	1.20	1.18
2011	6.74	5.83	184.27	149.50	116.94	92.91	1.19	1.16
2012	6.35	5.66	181.07	139.11	123.80	88.36	1.18	1.14
2013	6.28	5.49	180.65	128.84	130.24	81.69	1.16	1.13
2014	6.33	5.52	187.99	127.56	137.99	81.63	1.15	1.12
2015	6.36	5.46	194.16	128.43	144.79	83.82	1.15	1.11
2016	6.52	5.56	199.90	128.67	148.93	84.26	1.15	1.10
2017	6.72	5.78	203.56	130.93	156.07	85.88	1.15	1.09
2018	6.50	5.68	208.40	132.24	162.44	87.03	1.15	1.08
2019	6.21	5.62	209.00	135.24	164.01	89.92	1.16	1.08
2020	6.46	5.71	212.74	136.51	168.32	91.05	1.17	1.08
2021	6.71	5.71	210.46	138.13	169.76	93.25	1.19	1.09
2022	6.82	5.85	212.52	140.22	170.59	96.08	1.20	1.08
2023	7.10	5.98	211.25	139.76	173.43	94.59	1.20	1.08
2024	7.16	6.15	212.93	141.71	175.85	97.81	1.21	1.09
2025	7.29	6.14	211.92	142.21	178.37	98.50	1.22	1.09
2026	7.54	6.17	212.93	143.11	180.36	99.35	1.22	1.10
2027	7.69	6.25	213.87	145.43	181.53	100.81	1.22	1.11
2028	7.88	6.39	215.82	146.63	187.07	101.01	1.23	1.13
2029	8.04	6.48	216.21	148.95	186.41	102.53	1.23	1.13
2030	8.27	6.52	221.08	149.59	188.14	102.49	1.25	1.15

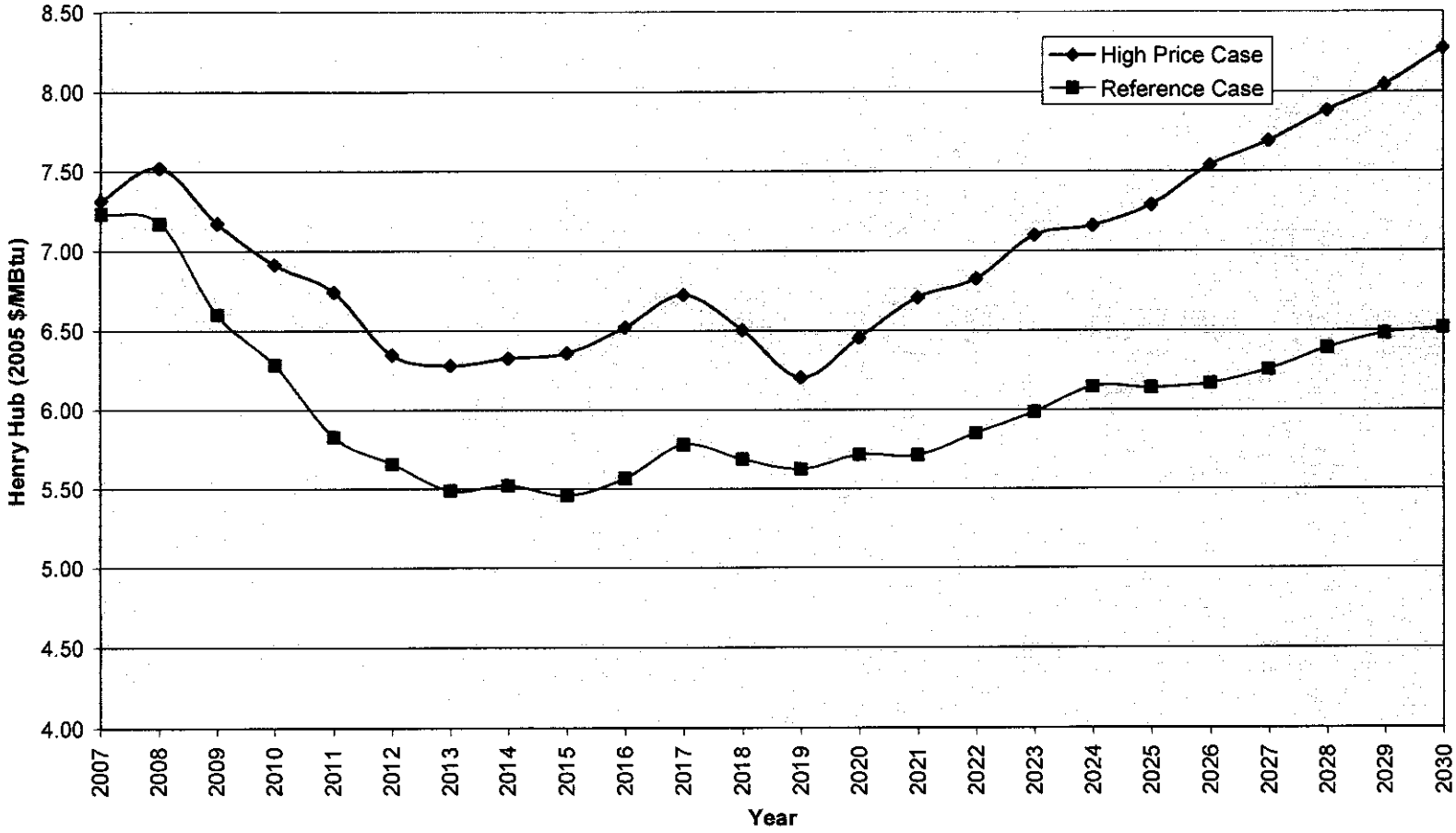


Figure 7-1
Comparison of Natural Gas Price Projections
AEO2007 High Price Case and AEO2007 Reference Case

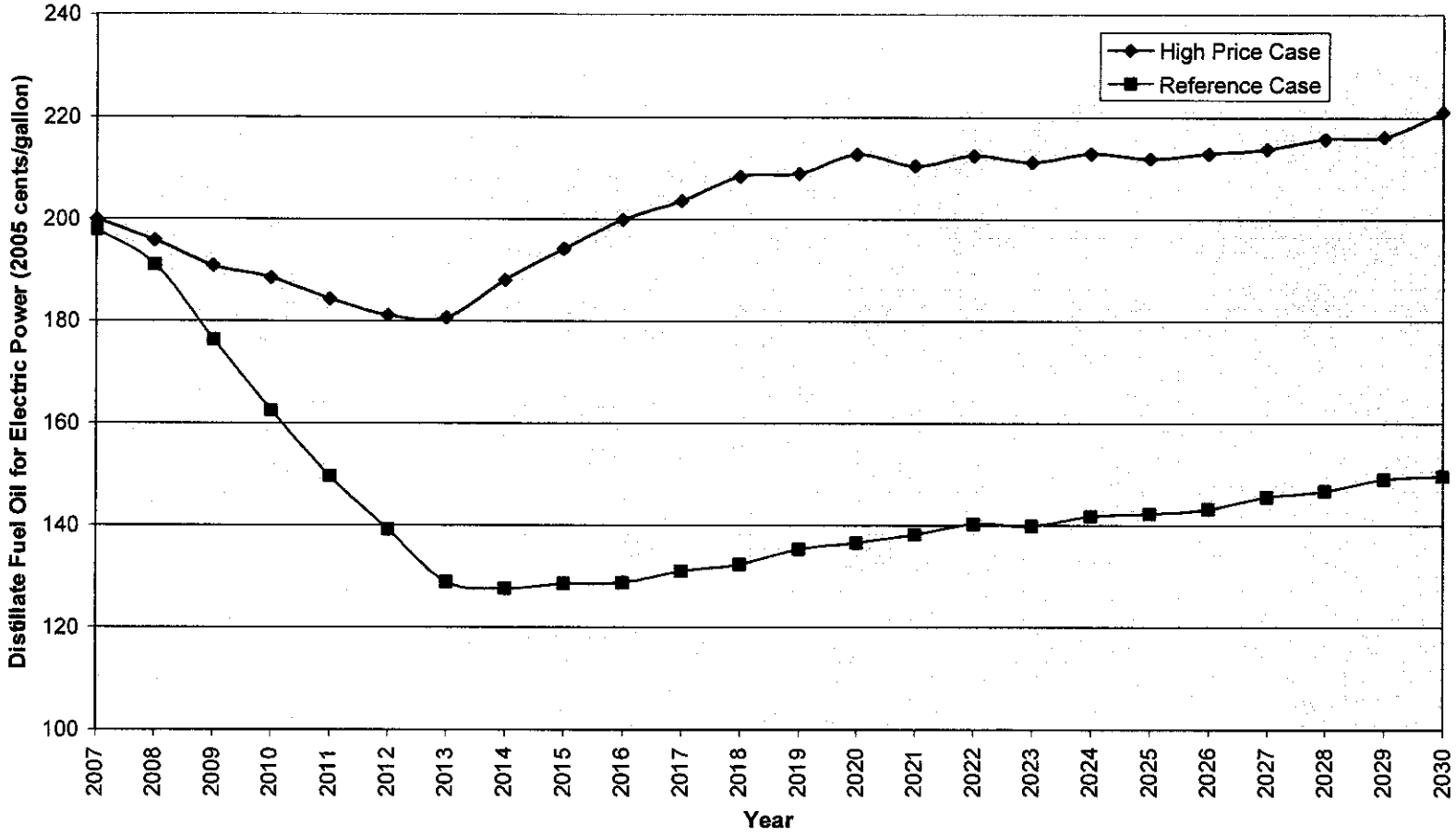


Figure 7-2
Comparison of Distillate Fuel Oil Price Projections
AEO2007 High Price Case and AEO2007 Reference Case

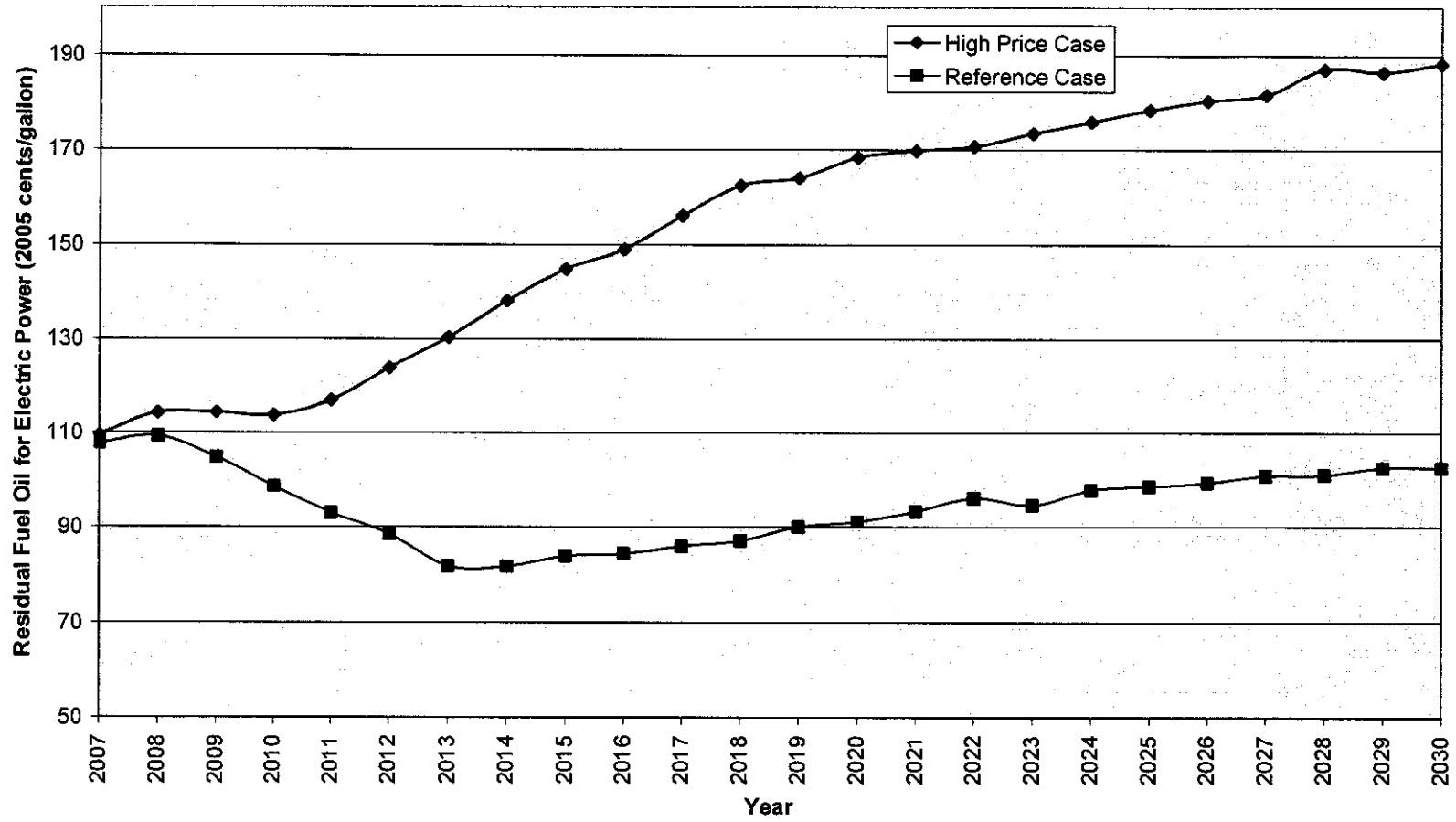


Figure 7-3
Comparison of Residual Fuel Oil Price Projections
AEO2007 High Price Case and AEO2007 Reference Case

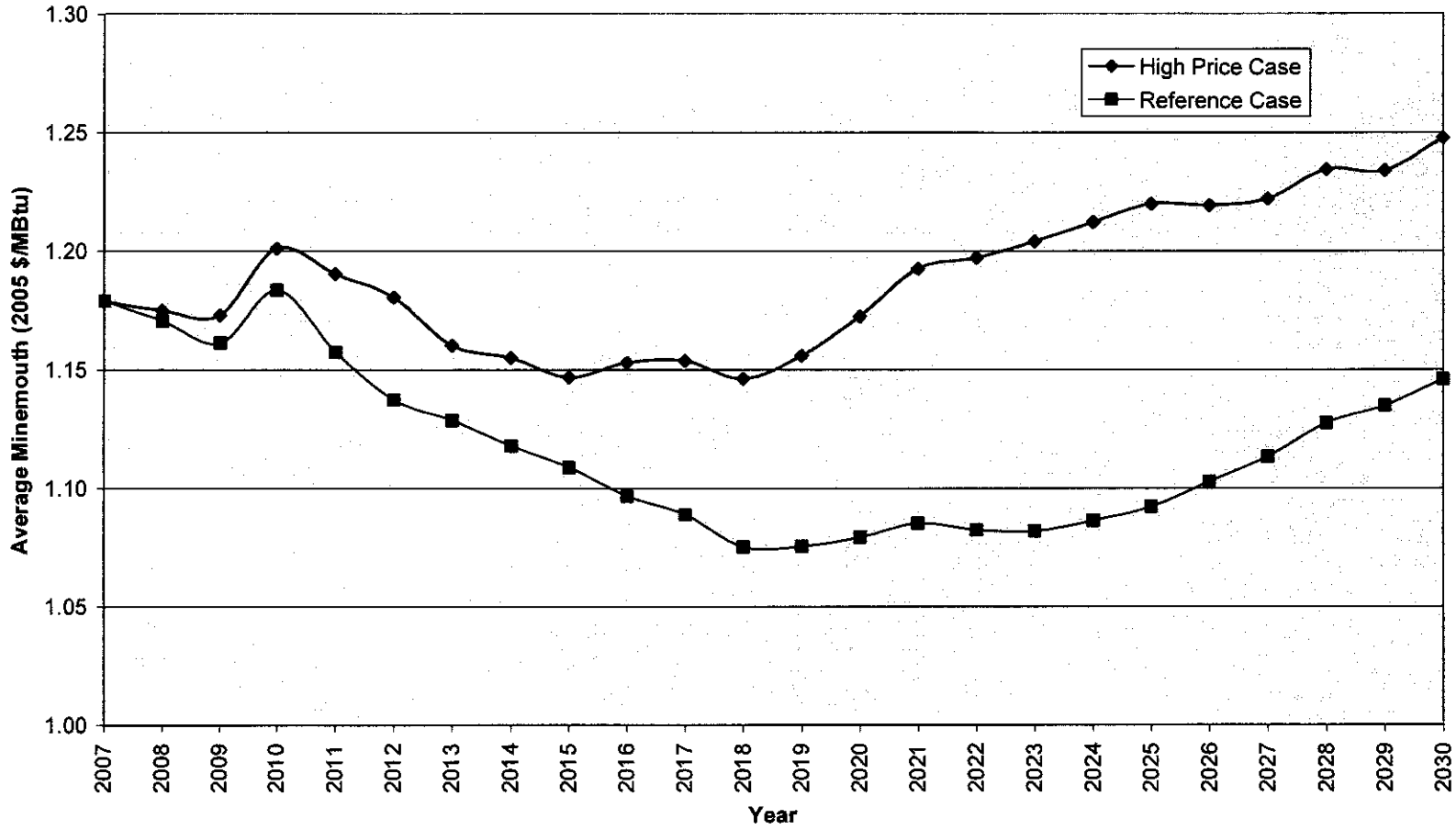


Figure 7-4
Comparison of Coal Price Projections
AEO2007 High Price Case and AEO2007 Reference Case

Table 7-4
Natural Gas, Fuel Oil, and Coal Price Projections
AEO2007 Low Price Case and AEO2007 Reference Case

Year	Natural Gas - Henry Hub (2005 $/MBtu)		Fuel Oil - Electric Power (2005 cents/gallon)				Coal - Average Minemouth (2005 $/MBtu)	
			Distillate		Residual			
	Low Price Case	Reference Case	Low Price Case	Reference Case	Low Price Case	Reference Case	Low Price Case	Reference Case
2007	6.99	7.23	197.77	197.82	107.81	107.69	1.18	1.18
2008	6.86	7.17	179.64	190.97	107.62	109.20	1.16	1.17
2009	6.12	6.60	154.68	176.19	97.02	104.67	1.14	1.16
2010	5.62	6.28	130.91	162.34	84.38	98.51	1.16	1.18
2011	5.23	5.83	112.16	149.50	73.79	92.91	1.13	1.16
2012	4.87	5.66	95.04	139.11	62.94	88.36	1.10	1.14
2013	4.59	5.49	84.14	128.84	58.27	81.69	1.08	1.13
2014	4.52	5.52	78.54	127.56	55.16	81.63	1.07	1.12
2015	4.41	5.46	75.42	128.43	53.12	83.82	1.05	1.11
2016	4.54	5.56	74.13	128.67	52.10	84.26	1.05	1.10
2017	4.61	5.78	70.12	130.93	52.88	85.88	1.03	1.09
2018	4.62	5.68	69.20	132.24	52.50	87.03	1.02	1.08
2019	4.66	5.62	71.92	135.24	52.65	89.92	1.01	1.08
2020	4.66	5.71	70.34	136.51	52.61	91.05	1.01	1.08
2021	4.82	5.71	70.75	138.13	53.29	93.25	1.01	1.09
2022	5.01	5.85	72.15	140.22	53.86	96.08	1.01	1.08
2023	5.06	5.98	72.53	139.76	53.57	94.59	1.01	1.08
2024	5.25	6.15	73.93	141.71	55.15	97.81	1.01	1.09
2025	5.20	6.14	78.01	142.21	56.31	98.50	1.00	1.09
2026	5.31	6.17	75.40	143.11	56.48	99.35	1.00	1.10
2027	5.38	6.25	75.86	145.43	55.77	100.81	1.00	1.11
2028	5.43	6.39	74.83	146.63	56.40	101.01	1.01	1.13
2029	5.47	6.48	74.72	148.95	54.79	102.53	1.01	1.13
2030	5.53	6.52	75.36	149.59	55.02	102.49	1.02	1.15

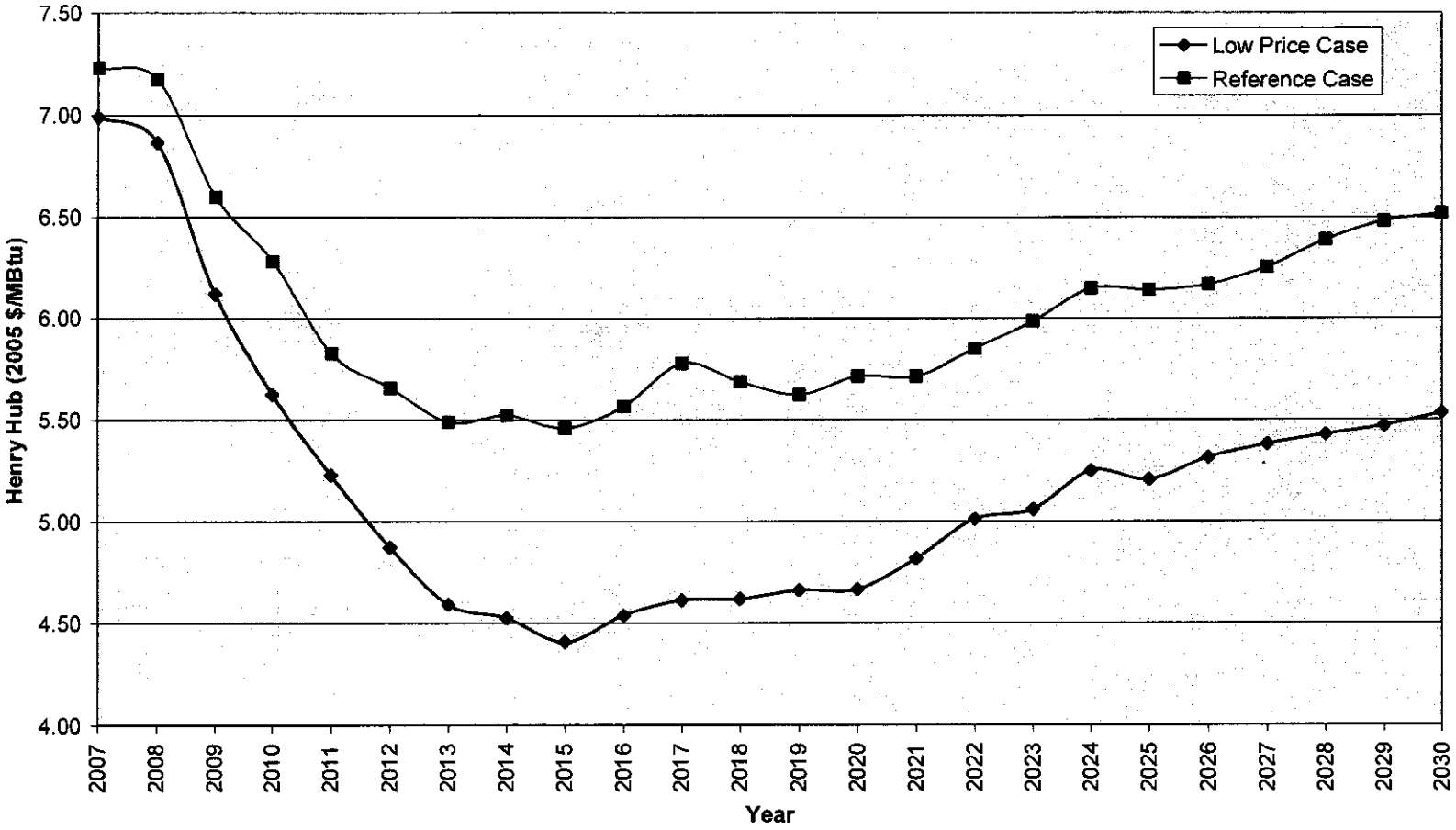


Figure 7-5
Comparison of Natural Gas Price Projections
AEO2007 Low Price Case and AEO2007 Reference Case

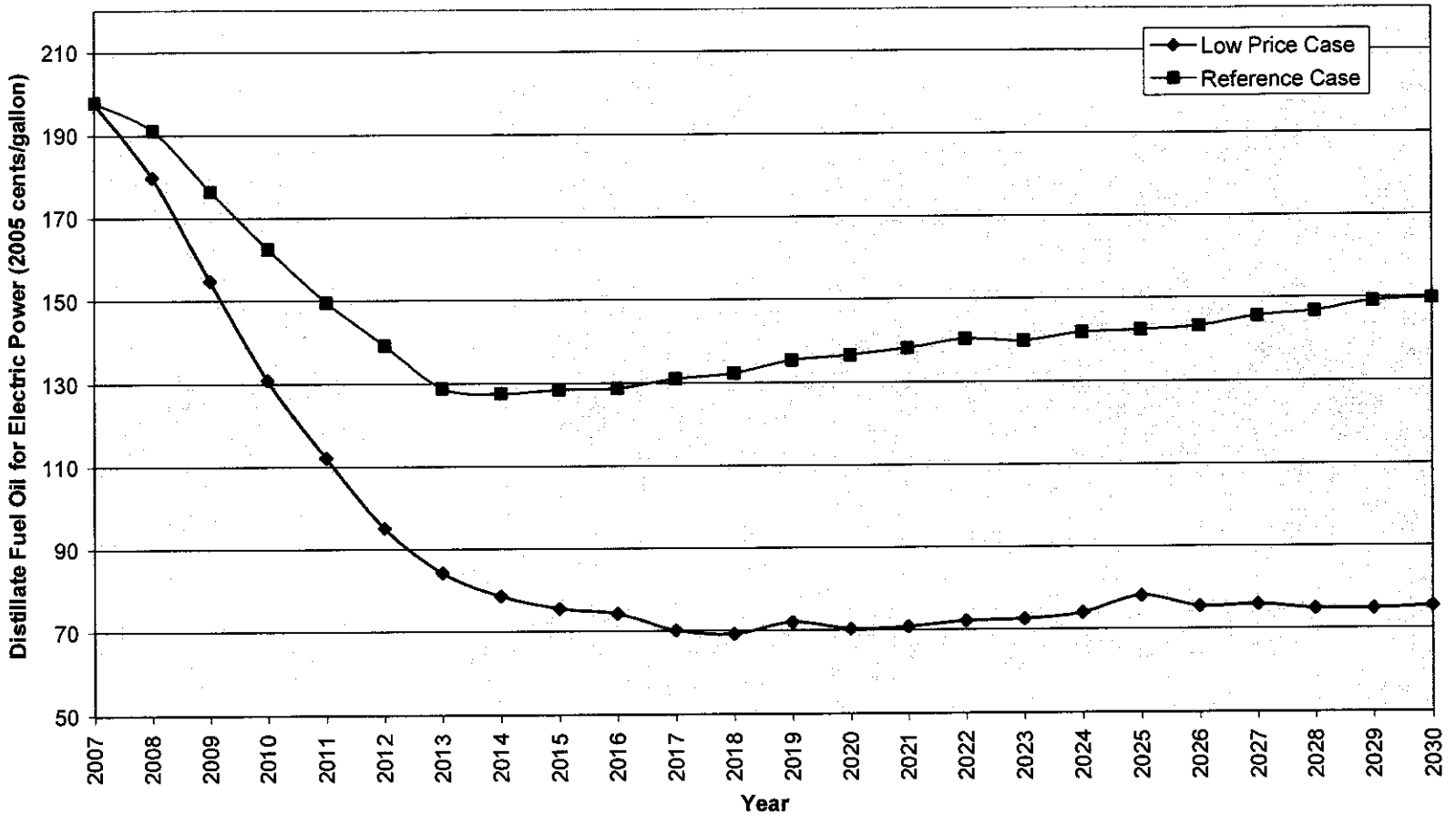


Figure 7-6
Comparison of Distillate Fuel Oil Price Projections
AEO2007 Low Price Case and AEO2007 Reference Case

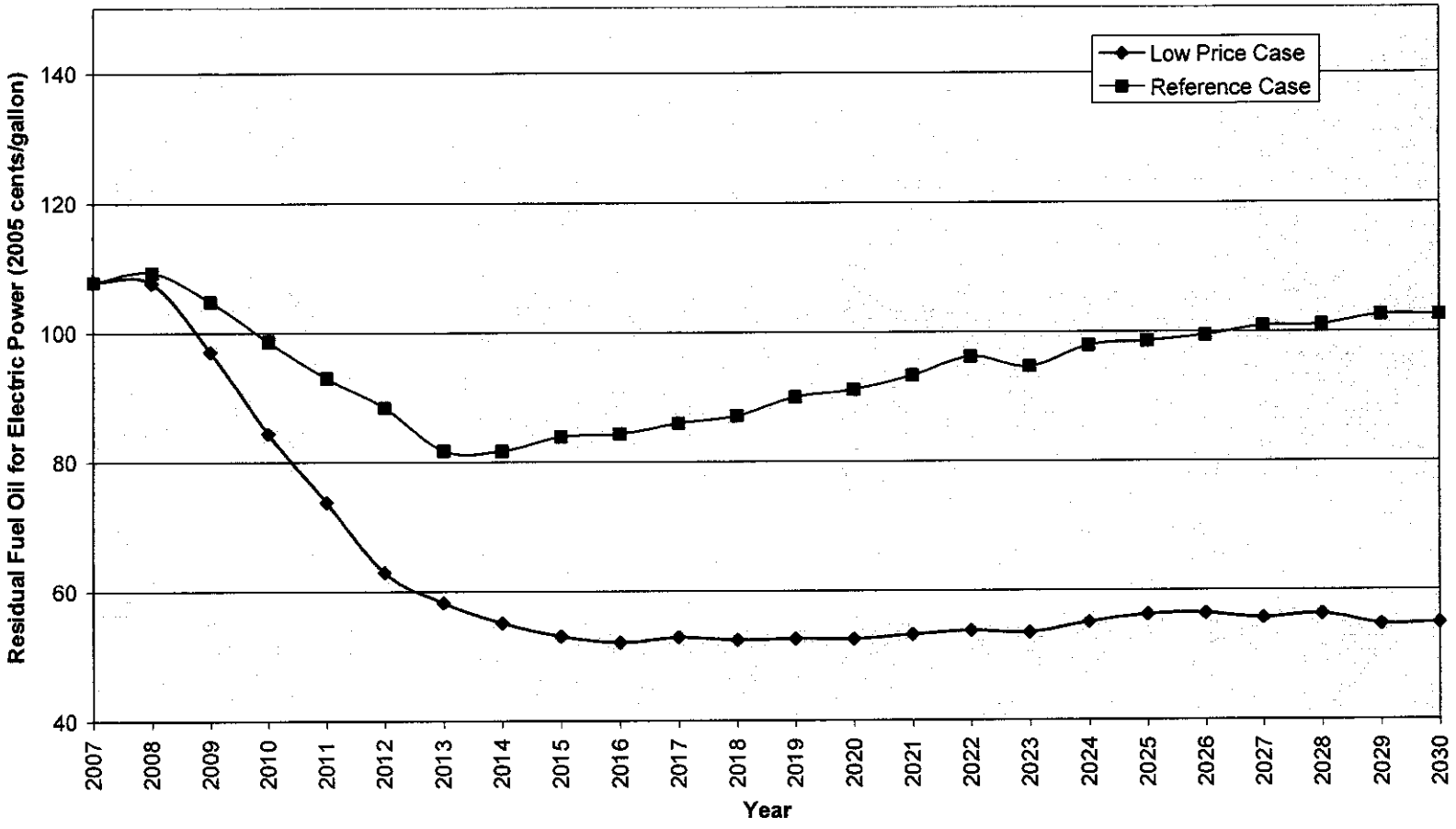


Figure 7-7
Comparison of Residual Fuel Oil Price Projections
AEO2007 Low Price Case and AEO2007 Reference Case

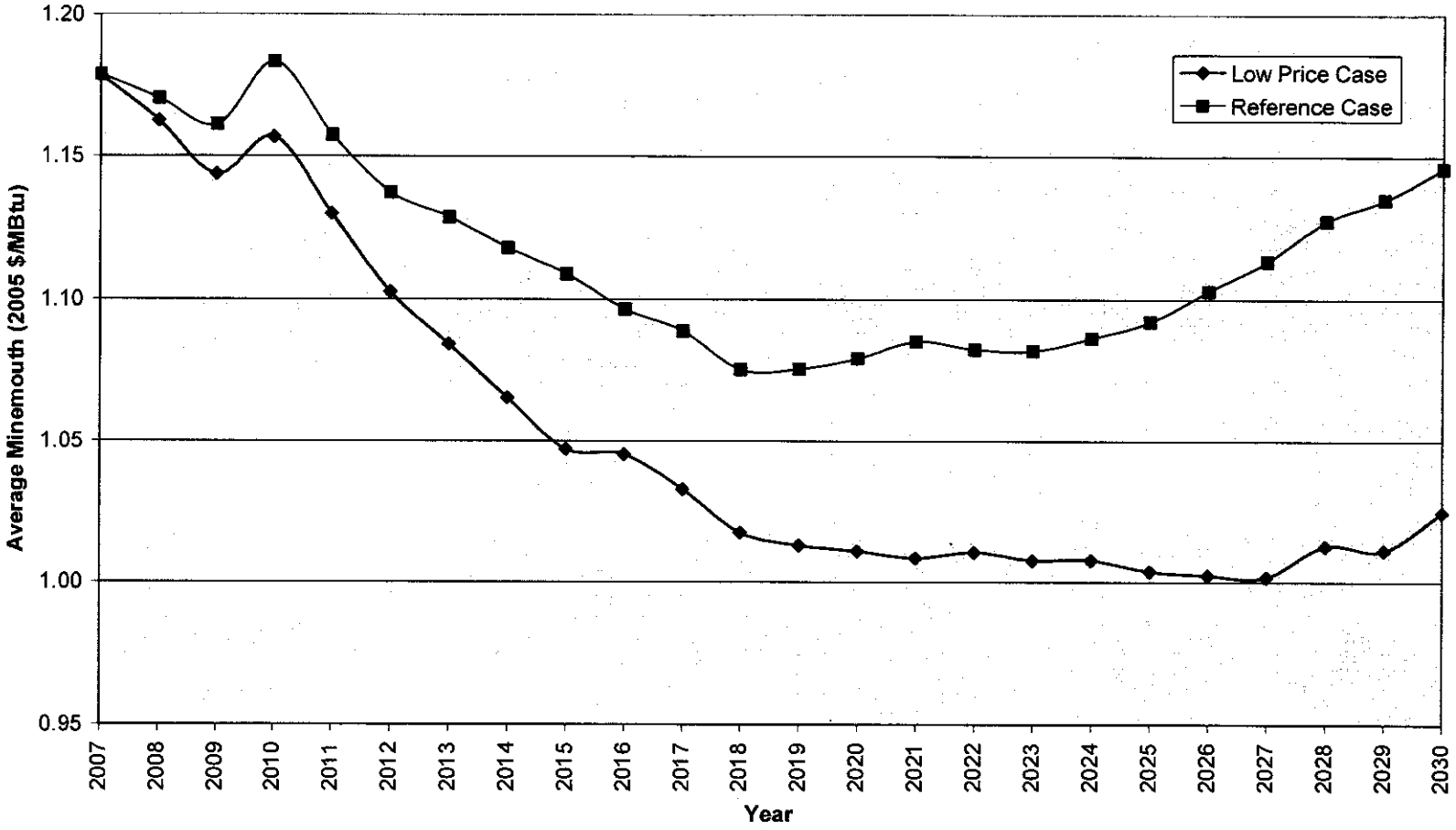


Figure 7-8
Comparison of Coal Price Projections
AEO2007 Low Price Case and AEO2007 Reference Case

7.5 FRCC High and Low Fuel Price Projections

As discussed in Section 7.4, the AEO2007 included High Price Case and Low Price Case fuel projections. Both the High and Low Price Case projections were developed on a national basis and, are therefore, not specific to the FRCC region. Adjustments were made to the High Price Case and Low Price Case natural gas, fuel oil, and coal price projections to develop high and low fuel price projections specific to the FRCC region. The following subsections discuss the methodology used to develop the FRCC-specific high and low fuel price projections and present the resulting annual natural gas, fuel oil, and coal price projections. Consideration of any additional intrastate transportation cost is discussed in Section 19.0.

7.5.1 High Fuel Price Projections for FRCC

7.5.1.1 High Natural Gas Prices. To develop natural gas price projections for the FRCC region, based on the AEO2007 High Price Case, the AEO2007 Reference Case natural gas price projections were analyzed to determine the annual differential between the FRCC-specific natural gas price projections presented in Table 7-1 and the Reference Case Henry Hub natural gas price projections presented in Table 7-3. The annual price differentials between natural gas delivered to the FRCC region and natural gas at Henry Hub derived from the Reference Case were held constant and added to the AEO2007 High Price Case Henry Hub natural gas price projections shown in Table 7-3. The resulting high natural gas price projections, specific to the FRCC region, are presented in Table 7-5.

7.5.1.2 High Distillate and Residual Fuel Oil Prices. High price projections for distillate and residual fuel oil, specific to the FRCC region, were developed by first converting the AEO2007 High Price and AEO2007 Reference Case projections (presented in Table 7-3) from cents per gallon to dollars per MBtu. The conversions were made by using the heat contents for distillate (138,690 Btu per gallon) and residual (149,690 Btu per gallon) used by the EIA. The annual transportation differentials for distillate and residual fuel oil between the AEO2007 Reference Case for the FRCC region (presented in Table 7-1) and for electric power usage in the United States as a whole (presented in Table 7-3) were determined. These annual transportation differentials for distillate and residual fuel oil were added to the AEO2007 High Price Case projections shown in Table 7-3 (after being converted to dollars per MBtu using the heat contents referenced previously). The resulting high distillate and residual fuel oil price projections, specific to the FRCC region, are presented in Table 7-5.

Table 7-5
Annual Energy Outlook 2007 High Case Price Projections
Forecast of Natural Gas, Fuel Oil, and Central Appalachian Coal Delivered to the Florida Reliability Coordinating Council[1]

Year	Natural Gas (2005 $/MBtu)[2]	Distillate Fuel Oil (2005 $/MBtu)	Residual Fuel Oil (2005 $/MBtu)	Low Sulfur Central Appalachian (0.54 lb S/MBtu) (2005 $/MBtu)
2007	7.74	16.27	8.60	2.89
2008	7.60	14.11	8.24	2.88
2009	7.26	13.72	7.90	2.89
2010	7.03	13.61	7.78	2.95
2011	6.84	13.42	8..00	2.99
2012	6.47	13.29	8.41	2.92
2013	6.43	13.22	9.11	2.91
2014	6.47	13.75	9.47	2.94
2015	6.52	14.19	9.85	2.91
2016	6.73	14.64	10.09	2.93
2017	6.90	14.91	10.58	2.90
2018	6.79	15.26	10.97	2.82
2019	6.56	15.27	11.05	2.77
2020	6.80	15.54	11.34	2.77
2021	7.02	15.38	11.41	2.77
2022	7.11	15.52	11.40	2.81
2023	7.33	15.43	11.62	2.82
2024	7.39	15.58	11.70	2.83
2025	7.53	15.51	11.86	2.82
2026	7.77	15.57	12.02	2.79
2027	7.93	15.65	12.04	2.77
2028	8.09	15.80	12.44	2.77
2029	8.19	15.82	12.40	2.76
2030	8.38	16.19	12.57	2.77

[1] Based on data presented in Supplemental Table 69 (Reference Case), Table 12 (Reference Case), Table 12 (High Price Case), Table 13 (Reference Case), and Table 13 (High Price Case) in the AEO2007.
[2] Natural gas price projections do not include usage charges or intrastate firm or interruptible transportation charges. These costs are accounted for in the economic analysis as discussed in Section 19.0 of this Application.

7.5.1.3 High Central Appalachian Coal Prices. The AEO2007 Reference Case Central Appalachian minemouth coal prices (annual dollars per ton)[3] were divided by the heat content of Central Appalachian coal (MBtu per ton),[4] resulting in Reference Case minemouth prices specific to Central Appalachian coal on a dollar per MBtu basis.

The AEO2007 Reference Case average minemouth coal prices for the United States were subtracted from the AEO2007 High Case average minemouth coal prices for the United States (each of which are presented in Table 7-3) to give an annual differential from the Reference Case to the High Case average US minemouth coal prices. This annual differential was applied to the Reference Case minemouth prices, specific to the Central Appalachian coal described above, to yield annual High Case minemouth prices, specific to Central Appalachian coal, on a dollar per MBtu basis.

An annual delivery adder (dollar per MBtu basis) that represents the cost of delivering Central Appalachian coal from the minemouth to the FRCC region was derived by calculating the difference between the annual Reference Case Central Appalachian minemouth prices and the AEO2007 Reference Case Central Appalachian coal prices for delivery to the FRCC Region. This annual delivery adder was applied to the High Case Central Appalachian coal minemouth prices, resulting in the High Price Case projections for Central Appalachian coal delivered to the FRCC region, which are presented in Table 7-5.

7.5.2 Low Fuel Price Projections for the FRCC

7.5.2.1 Low Natural Gas Prices. To develop natural gas price projections for the FRCC region, based on the AEO2007 Low Price Case, the AEO2007 Reference Case natural gas price projections were analyzed to determine the annual differential between the FRCC-specific natural gas price projections presented in Table 7-1 and the Reference Case Henry Hub natural gas price projections presented in Table 7-4. The annual price differentials between natural gas delivered to the FRCC region and natural gas at Henry Hub (derived from the Reference Case) were held constant and added to the AEO2007 Low Price Case Henry Hub natural gas price projections shown in Table 7-4. The resulting low natural gas price projections, specific to the FRCC region, are presented in Table 7-6.

[3] http://www.eia.doe.gov/oiaf/aeo/supplement/suptab_113.xls
[4] Table 71, http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/coal.pdf

Table 7-6
Annual Energy Outlook 2007 Low Case Price Projections
Forecast of Natural Gas, Fuel Oil, and Central Appalachian Coal Delivered to the Florida Reliability Coordinating Council[1]

Year	Natural Gas (2005 $/MBtu)[2]	Distillate Fuel Oil (2005 $/MBtu)	Residual Fuel Oil (2005 $/MBtu)	Low Sulfur Central Appalachian (0.54 lb S/MBtu) (2005 $/MBtu)
2007	7.41	16.12	8.49	2.89
2008	6.95	12.94	7.79	2.87
2009	6.21	11.12	6.75	2.86
2010	5.74	9.46	5.83	2.90
2011	5.33	8.22	5.11	2.93
2012	4.99	7.08	4.34	2.85
2013	4.74	6.26	4.31	2.84
2014	4.67	5.86	3.93	2.85
2015	4.56	5.63	3.73	2.81
2016	4.74	5.57	3.62	2.82
2017	4.79	5.29	3.69	2.78
2018	4.90	5.22	3.62	2.69
2019	5.02	5.38	3.61	2.63
2020	5.01	5.27	3.61	2.61
2021	5.13	5.30	3.63	2.58
2022	5.29	5.40	3.60	2.63
2023	5.29	5.43	3.61	2.63
2024	5.48	5.55	3.64	2.62
2025	5.44	5.85	3.70	2.60
2026	5.55	5.66	3.75	2.57
2027	5.62	5.70	3.64	2.55
2028	5.63	5.63	3.71	2.55
2029	5.62	5.62	3.61	2.54
2030	5.64	5.69	3.68	2.55

[1] Based on data presented in Supplemental Table 69 (Reference Case), Table 12 (Reference Case), Table 12 (Low Case), Table 13 (Reference Case), and Table 13 (Low Price Case) in the AEO2007.
[2] Natural gas price projections do not include usage charges or intrastate firm or interruptible transportation charges. These costs are accounted for in the economic analysis as discussed in Section 19.0 of this Application.

7.5.2.2 Low Distillate and Residual Fuel Oil Prices. Low Price projections for distillate and residual fuel oil, specific to the FRCC region, were developed by first converting the AEO2007 Low Price and AEO2007 Reference Case projections (presented in Table 7-4) from cents per gallon to dollars per MBtu. The conversions were made by using the heat contents for distillate (138,690 Btu per gallon) and residual (149,690 Btu per gallon) used by the EIA. The annual transportation differentials for distillate and residual fuel oil between the AEO2007 Reference Case for the FRCC region (presented in Table 7-1) and for electric power usage in the United States as a whole (presented in Table 7-4) were determined. These annual transportation differentials for distillate and residual fuel oil were added to the AEO2007 Low Price Case projections shown in Table 7-4 (after being converted to dollars per MBtu using the heat contents referenced previously). The resulting low distillate and residual fuel oil price projections, specific to the FRCC region, are presented in Table 7-6.

7.5.2.3 Low Central Appalachian Coal Prices. The AEO2007 Reference Case Central Appalachian minemouth coal prices (annual dollars per ton)[5] were divided by the heat content of Central Appalachian coal (MBtu per ton),[6] resulting in Reference Case minemouth prices specific to Central Appalachian coal on a dollars per MBtu basis.

The AEO2007 Low Case average minemouth coal prices for the United States were subtracted from the AEO2007 Reference Case average minemouth coal prices for the United States (each of which are presented in Table 7-3) to give an annual differential from the Reference Case to the Low Case average US minemouth coal prices. This annual differential was applied to the Reference Case minemouth prices, specific to Central Appalachian coal described above, to yield annual Low Case minemouth prices, specific to Central Appalachian coal, on a dollar per MBtu basis.

An annual delivery adder (dollar per MBtu basis) that represents the cost of delivering Central Appalachian coal from the minemouth to the FRCC region was derived by calculating the difference between the annual Reference Case Central Appalachian minemouth prices and the AEO2007 Reference Case Central Appalachian coal prices for delivery to the FRCC region. This annual delivery adder was applied to the Low Case Central Appalachian coal minemouth prices, resulting in the Low Price Case projections for Central Appalachian coal delivered to the FRCC region, which are presented in Table 7-6.

[5] http://www.eia.doe.gov/oiaf/aeo/supplement/suptab_113.xls
[6] Table 71, http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/coal.pdf

7.6 US Energy Information Administration Annual Energy Outlook 2007 Emissions Allowance Price Projections

As discussed in Subsections 7.6.1 and 7.6.2, the AEO2007 considers the potential impact of both CAIR and CAMR[7]. In addition to factoring the possible impacts of CAIR and CAMR into the fuel price projections, forecasts of emissions allowance prices for the emissions regulated by CAIR (SO_2 and NO_x) have been developed by the EIA. The emissions allowance price projections discussed in the remainder of this subsection were provided directly by the EIA and correspond to the assumptions used throughout the AEO2007 Reference Case.

The AEO2007 Reference Case projects a decrease in emissions of SO_2 from electricity generation on a nationwide basis, with SO_2 emissions projected to decrease from 10.2 million short tons in 2005 to 3.6 million short tons in 2030. The decrease in SO_2 emissions is due to both the use of lower sulfur coals as well as projected additions of flue gas desulfurization (FGD) equipment. AEO2007 projects a decrease in NO_x emissions from the electric power sector from 3.6 million short tons in 2005 to 2.3 million short tons in 2030. The decrease in NO_x emissions is due primarily to projected additions of selective catalytic reduction (SCR) equipment.

Table 7-7 presents the forecasts of SO_2 and NO_x emissions allowance prices that correspond to the AEO2007 Reference Case. Under CAIR, SO_2 emissions will be regulated beginning in 2010, while NO_x emissions will be regulated beginning in 2009. Table 7-7 presents emissions allowance prices beginning in 2009 for NO_x and 2010 for SO_2. The emissions allowance price projections shown in Table 7-7 are presented in constant 2005 dollars. For the economic analysis discussed in Section 20.0 of this Application, the SO_2 and NO_x emissions allowance price projections were converted from those values shown in Table 7-7 to nominal dollars by applying the 2.3 percent general inflation rate.

[7] Subsequent to completion of the AEO2007, the Federal District of Columbia Circuit Court of Appeals vacated the CAMR in a decision issued February 8, 2008. Since this Application does not consider the addition of any coal fired generating units as future resource alternatives, the impact of the current uncertainty associated with regulation of Hg emissions is insignificant in the analyses presented throughout this Application. Costs associated with emissions of Hg are not considered in this Application.

Table 7-7
Annual Energy Outlook 2007 Reference Case Price Projections Forecast of Emissions Allowance Prices for CAIR-Regulated Emissions[1]

Year	SO_2 (2005 $/ton)	NO_x (2005 $/ton)
2009	N/A	2,418.26
2010	638.68	2,515.04
2011	668.61	2,597.21
2012	763.16	2,554.95
2013	830.88	2,492.67
2014	857.12	2,540.85
2015	907.46	2,435.00
2016	984.29	2,585.31
2017	996.25	2,375.41
2018	1,018.47	2,590.91
2019	1,010.27	2,585.00
2020	1,041.84	2,548.46
2021	971.79	2,750.34
2022	1,056.70	2,876.16
2023	1,095.09	2,900.99
2024	1,077.72	3,052.68
2025	1,074.07	3,117.82
2026	1,078.38	3,135.95
2027	1,040.12	3,137.37
2028	950.09	3,052.77
2029	881.57	3,134.10
2030	815.49	3,306.56

[1] Based on data received directly from the EIA.

7.6.1 AEO2007 High Case Emissions Allowance Price Projections

Table 7-8 presents the forecasts of SO_2 and NO_x emissions allowance prices that correspond to the AEO2007 High Price Case. Under CAIR, SO_2 emissions will be regulated beginning in 2010, while NO_x emissions will be regulated beginning in 2009. Table 7-8 presents emissions allowance prices beginning in 2009 for NO_x and 2010 for SO_2. The emissions allowance price projections shown in Table 7-8 are presented in constant 2005 dollars.

7.6.2 AEO2007 Low Case Emissions Allowance Price Projections

Table 7-9 presents the forecasts of SO_2 and NO_x emissions allowance prices that correspond to the AEO2007 Low Price Case. Under CAIR, SO_2 emissions will be regulated beginning in 2010, while NO_x emissions will be regulated beginning in 2009. Table 7-9 presents emissions allowance prices beginning in 2009 for NO_x and 2010 for SO_2. The emissions allowance price projections shown in Table 7-9 are presented in constant 2005 dollars.

7.7 EIA Analysis of Senate Bill 280

Several bills that regulate emissions of greenhouse gases (including CO_2, methane, nitrous oxide, and fluorinated gas) have been proposed to the 110th US Congress. In response to a request from Senators Joseph Lieberman and John McCain, the EIA developed an analysis entitled *Energy Market and Economic Impacts of S.280, the Climate Stewardship and Innovation Act of 2007,* which was published in July 2007. The following subsections discuss this analysis and summarize the EIA's conclusions regarding projected CO_2 emissions allowance prices and associated impacts to the price of natural gas.

When this Application was prepared, the *Energy Market and Economic Impacts of S.280, the Climate Stewardship and Innovation Act of 2007*, was one of two published analyses by the EIA of proposed legislation to regulate CO_2. The second analysis was published by the EIA in January 2008 and is titled *Energy Market and Economic Impacts of S.1766, the Low Carbon Economy Act of 2007.* The CO_2 emissions allowance prices and corresponding natural gas price projections presented in the EIA's analysis of S.280 are generally higher than those presented in the EIA's analysis of S.1766. As a result, the EIA's analysis of S. 280 was selected for consideration in this Application.

Table 7-8
Annual Energy Outlook 2007 High Case Price Projections
Forecast of Emissions Allowance Prices for CAIR-Regulated Emissions[1]

Year	SO_2 (2005 $/ton)	NO_x (2005 $/ton)
2009	N/A	2,544.51
2010	707.17	2,589.96
2011	682.52	2,562.14
2012	712.87	2,497.36
2013	777.20	2,631.19
2014	863.65	2,633.98
2015	897.87	2,586.85
2016	957.47	2,487.41
2017	981.64	2,425.62
2018	913.05	2,631.64
2019	877.94	2,888.74
2020	897.01	3,016.03
2021	853.94	3,019.92
2022	884.94	3,050.75
2023	823.99	3,016.33
2024	808.01	2,946.68
2025	713.86	2,954.61
2026	616.53	2,892.34
2027	469.41	3,030.20
2028	350.70	2,939.25
2029	345.18	3,021.89
2030	449.97	3,134.93

[1] Based on data received directly from the EIA.

Table 7-9
Annual Energy Outlook 2007 Low Case Price Projections
Forecast of Emissions Allowance Prices for
CAIR-Regulated Emissions[1]

Year	SO_2 (2005 $/ton)	NO_x (2005 $/ton)
2009	N/A	2,476.43
2010	801.81	2,474.15
2011	811.10	2,478.09
2012	845.68	2,311.12
2013	902.96	2,207.68
2014	891.80	2,341.90
2015	949.11	2,432.51
2016	942.98	2,464.27
2017	936.51	2,320.38
2018	979.70	2,296.82
2019	982.49	2,392.80
2020	1,003.22	2,481.91
2021	1,101.17	2,574.81
2022	1,118.30	2,392.99
2023	1,120.06	2,514.97
2024	1,182.69	2,497.17
2025	1,154.87	2,583.94
2026	1,185.48	2,699.60
2027	1,172.82	2,744.43
2028	1,192.40	2,852.55
2029	1,175.34	2,848.03
2030	1,186.60	2,995.74

[1] Based on data received directly from the EIA.

7.7.1 Overview of the Proposed Climate Stewardship and Innovation Act of 2007 (S.280)

The *Climate Stewardship and Innovation Act of 2007* was introduced to the 110th US Congress as S.280 on January 12, 2007, by Senator Lieberman (for himself and Senator McCain, Senator Lincoln, Senator Snowe, Senator Obama, Senator Collins, and Senator Durbin). The legislative intent of S.280 is as follows:

> **To provide for a program to accelerate the reduction of greenhouse gas emissions in the United States by establishing a market-driven system of greenhouse gas tradeable allowances, to support the deployment of new climate change-related technologies, and to ensure benefits to consumers from the trading in such allowances, and for other purposes.**

As proposed, S.280 would cover the commercial, industrial, electric generation, and transportation sectors (the covered sectors). The regulations would cover entities within the covered sectors in possession or control of a source of emissions that emits, from any single facility owned by the entity, over 10,000 metric tons of greenhouse gases per year, measured in units of CO_2 equivalents. Such an entity is referred to as a covered entity.

The annual greenhouse gas emission targets set forth in S.280, measured in units of CO_2 equivalents, are summarized below. According to the EIA, the 2012 to 2019 emissions caps are approximately equal to the calendar year 2004 US greenhouse gas emissions, the 2020 to 2029 emissions caps are approximately equal to the calendar year 1990 US greenhouse gas emissions, the 2030 to 2049 emissions caps are approximately equal to 22 percent below the calendar year 1990 US greenhouse gas emissions, and the 2050 and beyond emissions caps are approximately equal to 60 percent below the calendar year 1990 US greenhouse gas emissions. The emission caps are as follows:

- For calendar years after 2011 - 6,130 million metric tons, reduced by the amount of emissions of greenhouse gases in calendar year 2012 from noncovered entities.
- For calendar years after 2019 - 5,239 million metric tons, reduced by the amount of emissions of greenhouse gases in calendar year 2020 from noncovered entities.
- For calendar years after 2029 – 4,100 million metric tons, reduced by the amount of emissions of greenhouse gases in calendar year 2030 from noncovered entities.

- For calendar years after 2049 – 2,096 million metric tons, reduced by the amount of emissions of greenhouse gases in each such calendar year from noncovered entities.

Under S.280, individual covered entities must submit allowances equal to their emissions, but their CO_2 emissions are not otherwise limited. Entities could buy and sell allowances, or bank allowances for future use. Under limited conditions, covered entities could also borrow allowance credits against future emissions reductions. Additionally, there are various alternative means of compliance including the following:

- Submitting tradeable allowances from another nation's market in greenhouse gas emissions.
- Submitting a registered net increase in sequestration.
- Submitting a greenhouse gas emissions reduction (other than a registered net increase in sequestration).
- Submitting credits related to assisting developing countries achieve sustainable development and reduce their greenhouse gas emissions.

7.7.2 EIA Analysis of S.280 – Overview and Summary of Results[8]

In developing its analysis of S.280, the EIA ran each of the policy cases described below through its integrated NEMS program. NEMS is developed and maintained by the EIA's Office of Integrated Analysis and Forecasting to provide projections of domestic energy-economy markets over the long term and to perform policy analyses requested by decision makers in various US government agencies (including the White House, Congress, and offices within the US Department of Energy, among others). NEMS is the modeling tool used by the EIA to develop the AEO2007. For the S.280 analysis, the EIA made adjustments to the AEO2007 Reference Case, which are delineated in Appendix C of the *Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007.* The adjustments encompass assumptions related to the treatment of ethanol and biodiesel, offshore wind technology, corn and biomass feedstock, interregional transmission cost structure, and biomass electricity generation.

[8] Refer to *Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007,* for additional details regarding the various policy cases and the analysis as a whole.

The use of NEMS allows for a fully integrated analysis of potential greenhouse gas emission allowance prices and energy demand. As stated in the EIA's analysis of S.280:

> **NEMS endogenously calculates changes in energy-related CO_2 emissions in the analysis cases. The cost of using each fossil fuel includes the costs associated with the GHG *[greenhouse gas]* allowances needed to cover the emissions produced when they are used. The adjustments influence energy demand and energy-related CO_2 emissions. The GHG allowance price also determines the reductions in the emissions of other GHGs and from international offsets based on abatement cost relationships...With emission allowance banking, NEMS solves for the time path of permit prices such that cumulative emissions match the cumulative emissions target without requiring allowance borrowing and with price escalation consistent with the average cost of capital to the electric power sector.**

The EIA analysis of S.280 includes several various policy cases and projections of associated CO_2 emissions allowance prices. The policy cases considered by the EIA in the analysis of S.280 are described as follows:

- S.280 Core--Represents the primary policy case.
- No International--Assumes that offsets from international sources are not available.
- Fixed 30 Percent Offsets--Assumes that offsets meet a fixed, 30 percent share of allowances.
- Unlimited Offsets--Assumes that an unlimited share of allowance obligations can be met by offsets.
- Low Discount--Assumes lower discount rate (4.0 percent) for allowance banking than S.280 Core (7.0 percent).
- High Auction--Assumes increased allowance auction share compared to S.280 Core.
- No Nuclear--Assumes no nuclear generating plant additions beyond the Reference Case level.
- Commercial Covered--Assumes that all commercial sector entities are covered.
- S.280 High Technology--S.280 Core with integrated high technology case assumptions (rather than Reference Case AEO2007).

In October 2007, the EIA published a supplement to its July 2007 analysis of S.280[9]. The supplemental analysis addressed topics related to the scenarios considered in recent EIA modeling and concerns related to prospects for building new coal fired power plants; additional scenarios restricting the availability of nuclear, biomass, and coal with carbon capture and sequestration (CCS) technology, the time horizon and state/regional detail in energy modeling; and EIA's analysis of natural gas. The additional policy cases presented in the supplemental analysis are as follows:

- Reference Nuclear and Biomass (RefNB)--Nuclear and biomass are held to their reference case (AEO2007) levels through 2030.
- Reference Nuclear and Biomass plus no CCS (RefNB+noCCS)--Further limits the RefNB case to preclude the deployment of coal with CCS prior to 2030.
- RefNBLNG+NoCCS--Further limits the RefNB+noCCS to hold liquefied natural gas (LNG) to its reference case (AEO2007) level through 2030.

The following tables and figures summarize results of the evaluations of the nine policy cases considered by the EIA in its analysis of S.280. Tables 7-10 through 7-13 present projections of annual natural gas, distillate fuel oil, residual fuel oil, and coal prices, respectively, for use in the electric power sector for each of the nine policy cases, as well as the corresponding annual price projections presented in the AEO2007 Reference Case. The annual natural gas price projections are presented in constant 2005 dollars per thousand cubic feet (mcf); the distillate and residual fuel oil prices are presented in constant 2005 cents per gallon; and the annual coal price projections are presented in constant 2005 dollars per MBtu. Annual natural gas and coal price projections are presented beginning in 2012, which is the initial year of CO_2 emissions regulations contemplated in S.280. It is important to note that the price projections for the nine policy cases presented in Tables 7-10 through 7-13 include the cost of CO_2 emissions allowances, while no such costs are included in the annual price projections for the AEO2007 Reference Case. Table 7-14 presents projections of annual CO_2 emissions allowance prices for each of the nine policy cases, in constant 2005 dollars per metric ton CO_2 equivalent, beginning in 2012. Figure 7-9 through Figure 7-13 present graphical depictions of the data in Tables 7-10 through 7-14, respectively.

[9] Refer to Supplement to *Energy Market and Economic Impacts of S.280, the Climate Stewardship and Innovation Act of 2007*, located at http://www.eia.doe.gov/oiaf/servicerpt/biv/index.html.

Table 7-10
Natural Gas Price Projections for AEO2007 Reference Case and EIA Analysis of S.280
(Delivered 2005 $/mcf – Electric Power Sector, Including Cost of CO_2 Allowances for S.280 Cases)

Year	AEO 2007 Reference Case	S. 280 Core	S. 280 No International	S. 280 Fixed 30% Offset	S. 280 No Nuclear	S. 280 Low Discount	S. 280 Unlimited Offset	S. 280 High Auction	S. 280 Commercial Covered	S. 280 High Technology	S. 280 Ref NB	S. 280 RefNB + noCCS	S. 280 RefNBLNG + noCCS
2012	$5.86	$6.58	$6.87	$6.21	$6.55	$6.68	$6.56	$6.52	$6.53	$6.26	$6.58	$6.63	$6.68
2013	$5.66	$6.31	$6.52	$5.95	$6.32	$6.50	$6.33	$6.34	$6.30	$6.06	$6.37	$6.46	$6.45
2014	$5.70	$6.34	$6.46	$5.97	$6.43	$6.43	$6.33	$6.28	$6.28	$5.96	$6.64	$6.54	$6.98
2015	$5.66	$6.28	$6.59	$6.02	$6.42	$6.49	$6.38	$6.30	$6.27	$6.04	$6.59	$7.03	$6.95
2016	$5.76	$6.41	$6.65	$6.14	$6.54	$6.58	$6.50	$6.37	$6.37	$6.03	$6.72	$7.08	$7.06
2017	$5.96	$6.60	$6.80	$6.35	$6.69	$6.67	$6.65	$6.54	$6.59	$6.17	$6.97	$7.30	$7.31
2018	$5.89	$6.59	$6.80	$6.28	$6.78	$6.63	$6.59	$6.53	$6.60	$6.14	$7.00	$7.42	$7.39
2019	$5.84	$6.66	$6.87	$6.30	$6.82	$6.59	$6.62	$6.60	$6.61	$6.10	$7.11	$7.53	$7.49
2020	$5.93	$6.73	$7.07	$6.45	$6.94	$6.62	$6.76	$6.70	$6.66	$6.23	$7.23	$7.58	$7.61
2021	$5.89	$6.83	$7.26	$6.58	$7.03	$6.64	$6.74	$6.78	$6.80	$6.31	$7.32	$7.75	$7.91
2022	$6.01	$7.05	$7.41	$6.82	$7.21	$6.75	$6.74	$6.95	$7.00	$6.51	$7.64	$8.04	$8.18
2023	$6.12	$7.21	$7.59	$6.96	$7.38	$6.86	$6.70	$7.10	$7.18	$6.63	$7.90	$8.38	$8.52
2024	$6.23	$7.31	$7.37	$7.18	$7.58	$6.92	$6.73	$7.26	$7.30	$6.76	$8.11	$8.73	$8.86
2025	$6.22	$7.50	$7.65	$7.31	$7.74	$7.04	$6.89	$7.47	$7.45	$6.87	$8.05	$8.97	$9.11
2026	$6.24	$7.67	$7.93	$7.42	$7.97	$7.16	$7.01	$7.61	$7.62	$7.04	$8.45	$9.29	$9.52
2027	$6.33	$7.77	$8.36	$7.62	$8.22	$7.33	$7.06	$7.74	$7.74	$7.18	$8.73	$9.63	$9.87
2028	$6.43	$7.89	$8.57	$7.71	$8.52	$7.38	$7.07	$7.87	$7.88	$7.35	$8.95	$9.99	$10.17
2029	$6.50	$8.08	$8.55	$7.78	$8.78	$7.42	$7.16	$8.09	$8.02	$7.52	$9.33	$10.37	$10.53
2030	$6.51	$8.38	$8.85	$7.82	$9.09	$7.44	$7.23	$8.34	$8.32	$7.73	$9.57	$10.74	$11.07

Table 7-11
Distillate Fuel Oil Price Projections for AEO2007 Reference Case and EIA Analysis of S.280
(Delivered 2005 Cents/Gallon – Electric Power Sector, Including Cost of CO_2 Allowances for S.280 Cases)

Year	AEO 2007 Reference Case	S. 280 Core	S. 280 No International	S. 280 Fixed 30% Offset	S. 280 No Nuclear	S. 280 Low Discount	S. 280 Unlimited Offset	S. 280 High Auction	S. 280 Commercial Covered	S. 280 High Technology	S. 280 Ref NB	S. 280 RefNB + noCCS	S. 280 RefNBLNG + noCCS
2012	138.38	150.81	155.56	145.62	151.04	153.78	151.17	150.77	150.65	149.25	151.91	153.01	153.37
2013	126.90	140.64	144.63	134.99	140.66	143.13	141.15	140.70	140.37	138.55	141.48	143.50	143.58
2014	125.75	140.23	144.86	134.90	140.57	143.09	140.48	140.29	140.27	137.92	141.72	143.56	144.48
2015	126.60	141.08	147.04	135.99	142.05	144.17	141.08	141.38	141.01	138.80	143.12	145.56	146.04
2016	127.42	142.87	149.27	137.23	143.55	145.10	142.06	142.74	142.30	139.33	144.86	148.00	148.17
2017	130.13	146.48	153.04	140.95	147.39	148.21	144.64	146.66	146.16	142.43	148.55	151.72	151.44
2018	131.88	149.20	156.12	143.69	150.13	149.98	146.54	149.07	148.62	144.79	151.49	154.84	154.55
2019	135.33	154.94	161.04	147.60	155.81	155.11	151.76	154.22	153.85	147.89	156.89	159.26	159.26
2020	136.50	156.33	163.88	149.96	157.80	156.15	153.18	156.33	155.76	150.82	158.96	162.93	163.08
2021	137.70	160.20	167.78	152.41	161.85	159.22	155.74	160.01	159.55	154.11	163.01	167.23	167.50
2022	139.90	164.24	173.70	155.08	165.42	162.04	156.09	164.59	163.12	158.00	167.24	171.98	172.27
2023	140.18	166.71	176.96	157.90	168.51	163.55	156.02	167.03	165.69	160.17	170.12	174.98	175.50
2024	141.66	171.02	176.34	161.14	173.01	166.88	157.46	171.27	170.09	163.26	174.57	179.65	180.12
2025	142.54	174.90	180.54	164.02	176.96	169.04	160.00	175.38	173.85	167.08	178.49	183.99	184.16
2026	143.87	178.84	185.27	167.38	180.97	171.97	163.17	179.12	177.59	169.80	182.84	188.92	189.27
2027	144.86	183.24	190.41	172.75	185.01	174.80	168.67	183.32	181.63	173.76	187.18	193.56	193.98
2028	147.71	187.35	196.04	176.52	189.17	178.53	172.25	187.66	186.18	177.15	191.91	198.96	199.49
2029	149.97	192.21	201.33	180.87	194.52	182.77	177.60	191.98	190.66	182.01	197.74	204.96	204.96
2030	152.83	196.35	206.68	184.46	199.96	185.79	179.66	196.70	194.73	185.92	202.73	210.01	210.03

Table 7-12
Residual Fuel Oil Price Projections for AEO2007 Reference Case and EIA Analysis of S.280
(Delivered 2005 Cents/Gallon – Electric Power Sector, Including Cost of CO_2 Allowances for S.280 Cases)

Year	AEO 2007 Reference Case	S. 280 Core	S. 280 No International	S. 280 Fixed 30% Offset	S. 280 No Nuclear	S. 280 Low Discount	S. 280 Unlimited Offset	S. 280 High Auction	S. 280 Commercial Covered	S. 280 High Technology	S. 280 Ref NB	S. 280 RefNB + noCCS	S. 280 RefNBLNG + noCCS
2012	88.00	136.63	146.49	123.72	137.14	140.36	134.85	137.03	136.08	148.38	134.76	134.86	137.19
2013	80.80	119.45	125.27	108.51	119.44	125.64	120.15	119.48	119.05	132.56	116.99	118.50	120.70
2014	81.65	129.07	130.50	113.75	129.72	132.52	130.20	127.53	127.77	138.28	123.61	128.10	133.31
2015	83.14	134.78	140.80	130.67	136.85	141.32	138.89	135.63	131.42	141.62	137.62	134.27	136.61
2016	83.66	140.00	151.68	132.75	142.25	146.57	141.92	141.16	136.13	145.59	142.55	144.66	148.71
2017	85.53	145.54	156.15	139.48	149.91	151.24	146.35	145.43	144.34	155.55	148.76	152.19	156.92
2018	86.97	151.24	164.27	145.33	154.68	153.74	155.81	151.46	150.69	166.16	156.69	159.13	162.04
2019	89.71	161.00	179.15	151.62	162.13	163.70	160.14	160.72	160.99	175.69	165.20	167.15	167.98
2020	90.57	166.47	187.23	154.63	165.02	165.81	163.20	165.43	166.45	178.82	167.07	169.19	169.72
2021	92.55	173.85	190.12	159.55	172.16	173.81	169.20	174.29	174.56	178.59	174.62	175.82	177.07
2022	95.20	177.54	193.81	165.33	176.54	176.00	169.90	177.37	177.49	184.93	178.36	182.64	183.41
2023	94.37	183.59	202.56	165.59	181.17	179.55	165.70	183.48	182.81	194.85	182.78	187.58	186.80
2024	97.35	191.20	206.38	173.04	185.58	183.56	170.53	192.58	188.73	197.82	187.76	193.27	194.29
2025	98.67	198.35	215.47	178.08	193.44	190.21	173.65	199.55	199.19	202.90	195.98	199.65	201.40
2026	99.04	206.59	223.24	183.29	199.62	193.86	182.59	207.22	206.53	208.84	207.00	206.19	207.31
2027	100.18	212.29	232.15	187.29	209.87	199.08	189.10	220.94	214.81	212.89	210.84	214.09	213.38
2028	102.34	221.36	242.32	193.80	214.48	203.03	194.26	224.84	222.35	216.25	214.72	224.25	219.15
2029	102.90	231.45	248.25	200.23	225.03	207.89	203.75	231.09	227.84	219.61	228.46	233.95	229.00
2030	104.92	234.75	251.97	202.88	230.76	211.31	206.63	236.99	234.34	223.72	238.98	238.65	236.54

Table 7-13
Coal Price Projections for AEO2007 Reference Case and EIA Analysis of S.280
(Delivered 2005 $/MBtu – Electric Power Sector, Including Cost of CO_2 Allowances for S.280 Cases)

Year	AEO 2007 Reference Case	S. 280 Core	S. 280 No International	S. 280 Fixed 30% Offset	S. 280 No Nuclear	S. 280 Low Discount	S. 280 Unlimited Offset	S. 280 High Auction	S. 280 Commercial Covered	S. 280 High Technology	S. 280 Ref NB	S. 280 RefNB + noCCS	S. 280 RefNBLNG + noCCS
2012	$1.65	$2.86	$3.29	$2.36	$2.85	$3.12	$2.86	$2.85	$2.84	$2.75	$2.95	$3.07	$3.08
2013	$1.62	$2.89	$3.26	$2.39	$2.88	$3.15	$2.89	$2.89	$2.89	$2.78	$2.99	$3.17	$3.18
2014	$1.61	$2.93	$3.38	$2.44	$2.97	$3.20	$2.94	$2.93	$2.93	$2.82	$3.06	$3.28	$3.29
2015	$1.60	$2.98	$3.52	$2.49	$3.06	$3.26	$2.98	$2.99	$2.97	$2.81	$3.15	$3.40	$3.40
2016	$1.59	$3.09	$3.66	$2.56	$3.18	$3.32	$3.00	$3.10	$3.04	$2.83	$3.26	$3.52	$3.53
2017	$1.58	$3.20	$3.82	$2.63	$3.30	$3.38	$3.02	$3.22	$3.16	$2.93	$3.39	$3.67	$3.68
2018	$1.57	$3.32	$3.99	$2.70	$3.42	$3.44	$3.08	$3.33	$3.27	$3.02	$3.52	$3.82	$3.84
2019	$1.58	$3.45	$4.17	$2.79	$3.56	$3.51	$3.19	$3.47	$3.40	$3.13	$3.67	$4.00	$4.02
2020	$1.57	$3.59	$4.35	$2.88	$3.72	$3.58	$3.32	$3.61	$3.54	$3.24	$3.84	$4.19	$4.21
2021	$1.57	$3.75	$4.56	$2.99	$3.88	$3.66	$3.33	$3.77	$3.69	$3.37	$4.02	$4.39	$4.42
2022	$1.58	$3.93	$4.79	$3.11	$4.07	$3.74	$3.19	$3.95	$3.86	$3.52	$4.23	$4.63	$4.66
2023	$1.60	$4.11	$5.02	$3.23	$4.27	$3.83	$3.09	$4.13	$4.03	$3.68	$4.44	$4.87	$4.91
2024	$1.61	$4.31	$4.79	$3.37	$4.48	$3.91	$3.01	$4.33	$4.23	$3.84	$4.68	$5.14	$5.18
2025	$1.62	$4.52	$5.04	$3.53	$4.71	$4.01	$3.15	$4.55	$4.44	$4.02	$4.97	$5.43	$5.48
2026	$1.64	$4.74	$5.29	$3.68	$4.96	$4.11	$3.28	$4.78	$4.65	$4.20	$5.23	$5.76	$5.80
2027	$1.65	$4.99	$5.65	$3.85	$5.23	$4.21	$3.42	$5.02	$4.89	$4.41	$5.51	$6.09	$6.14
2028	$1.67	$5.27	$5.95	$4.04	$5.55	$4.31	$3.56	$5.30	$5.16	$4.63	$5.86	$6.47	$6.52
2029	$1.68	$5.54	$6.26	$4.23	$5.88	$4.42	$3.72	$5.56	$5.43	$4.88	$6.20	$6.88	$6.95
2030	$1.70	$5.85	$6.63	$4.45	$6.25	$4.52	$3.90	$5.84	$5.72	$5.12	$6.59	$7.30	$7.39

Table 7-14
CO_2 Emission Allowance Price Projections from EIA Analysis of S.280
(2005 $/Metric Ton CO_2 Equivalent)

Year	S. 280 Core	S. 280 No International	S. 280 Fixed 30% Offset	S. 280 No Nuclear	S. 280 Low Discount	S. 280 Unlimited Offset	S. 280 High Auction	S. 280 Commercial Covered	S. 280 High Technology	S. 280 Ref NB	S. 280 RefNB + noCCS	S. 280 RefNBLNG + noCCS
2012	$13.21	$18.00	$7.76	$13.14	$16.06	$13.25	$13.14	$13.09	$12.13	$14.06	$15.31	$15.47
2013	$13.86	$17.88	$8.38	$13.78	$16.70	$13.91	$13.79	$13.80	$12.83	$14.65	$16.54	$16.71
2014	$14.44	$19.31	$9.06	$14.76	$17.37	$14.60	$14.44	$14.44	$13.42	$15.51	$17.86	$18.05
2015	$15.09	$20.86	$9.78	$15.94	$18.06	$15.06	$15.23	$15.02	$13.38	$16.75	$19.29	$19.49
2016	$16.29	$22.53	$10.56	$17.22	$18.78	$15.34	$16.45	$15.84	$13.68	$18.09	$20.83	$21.05
2017	$17.60	$24.33	$11.41	$18.60	$19.54	$15.69	$17.77	$17.11	$14.78	$19.54	$22.50	$22.74
2018	$19.00	$26.27	$12.32	$20.08	$20.32	$16.38	$19.19	$18.47	$15.96	$21.10	$24.30	$24.56
2019	$20.52	$28.38	$13.31	$21.69	$21.13	$17.69	$20.72	$19.95	$17.24	$22.79	$26.24	$26.52
2020	$22.17	$30.65	$14.37	$23.43	$21.98	$19.11	$22.38	$21.55	$18.62	$24.61	$28.34	$28.64
2021	$23.94	$33.10	$15.52	$25.30	$22.85	$19.24	$24.17	$23.27	$20.11	$26.58	$30.61	$30.93
2022	$25.85	$35.74	$16.76	$27.32	$23.77	$17.84	$26.11	$25.13	$21.71	$28.71	$33.06	$33.41
2023	$27.92	$38.60	$18.10	$29.51	$24.72	$16.79	$28.19	$27.15	$23.45	$31.01	$35.70	$36.08
2024	$30.16	$36.29	$19.55	$31.87	$25.71	$15.96	$30.45	$29.32	$25.33	$33.49	$38.56	$38.97
2025	$32.57	$39.19	$21.11	$34.42	$26.74	$17.23	$32.89	$31.66	$27.35	$36.16	$41.64	$42.08
2026	$35.17	$42.32	$22.80	$37.17	$27.81	$18.61	$35.52	$34.20	$29.54	$39.06	$44.98	$45.45
2027	$37.99	$45.71	$24.63	$40.15	$28.92	$20.10	$38.36	$36.93	$31.91	$42.18	$48.57	$49.09
2028	$41.03	$49.37	$26.60	$43.36	$30.07	$21.71	$41.43	$39.89	$34.46	$45.56	$52.46	$53.01
2029	$44.31	$53.32	$28.73	$46.83	$31.28	$23.45	$44.74	$43.08	$37.22	$49.20	$56.66	$57.25
2030	$47.85	$57.58	$31.02	$50.58	$32.53	$25.32	$48.32	$46.52	$40.19	$53.14	$61.19	$61.83

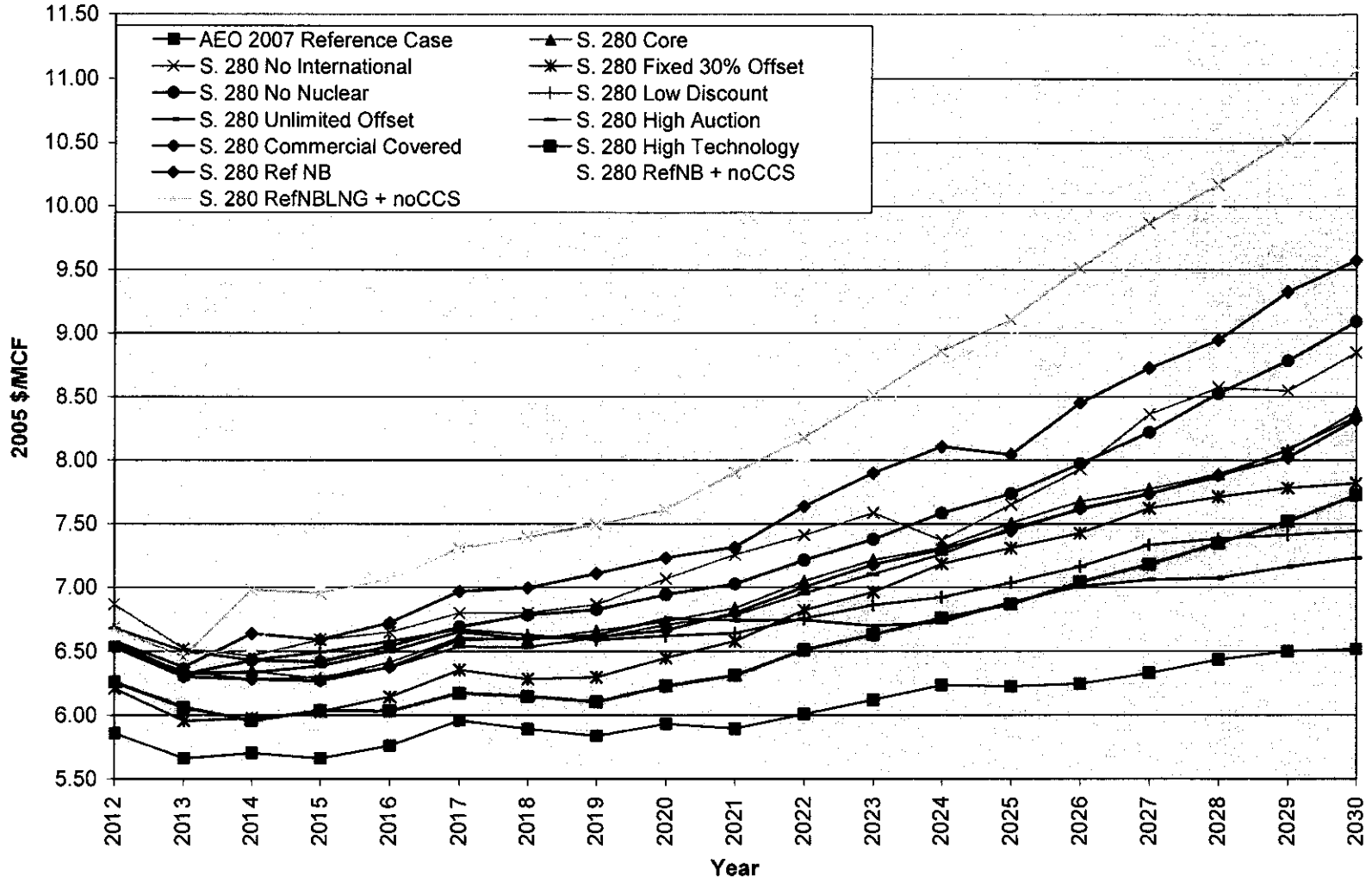


Figure 7-9
Natural Gas Price Projections for AEO2007 Reference Case and EIA Analysis of S.280
(Delivered 2005 $/mcf - Electric Power Sector, Including Cost of CO_2 Allowances for S.280 Cases)

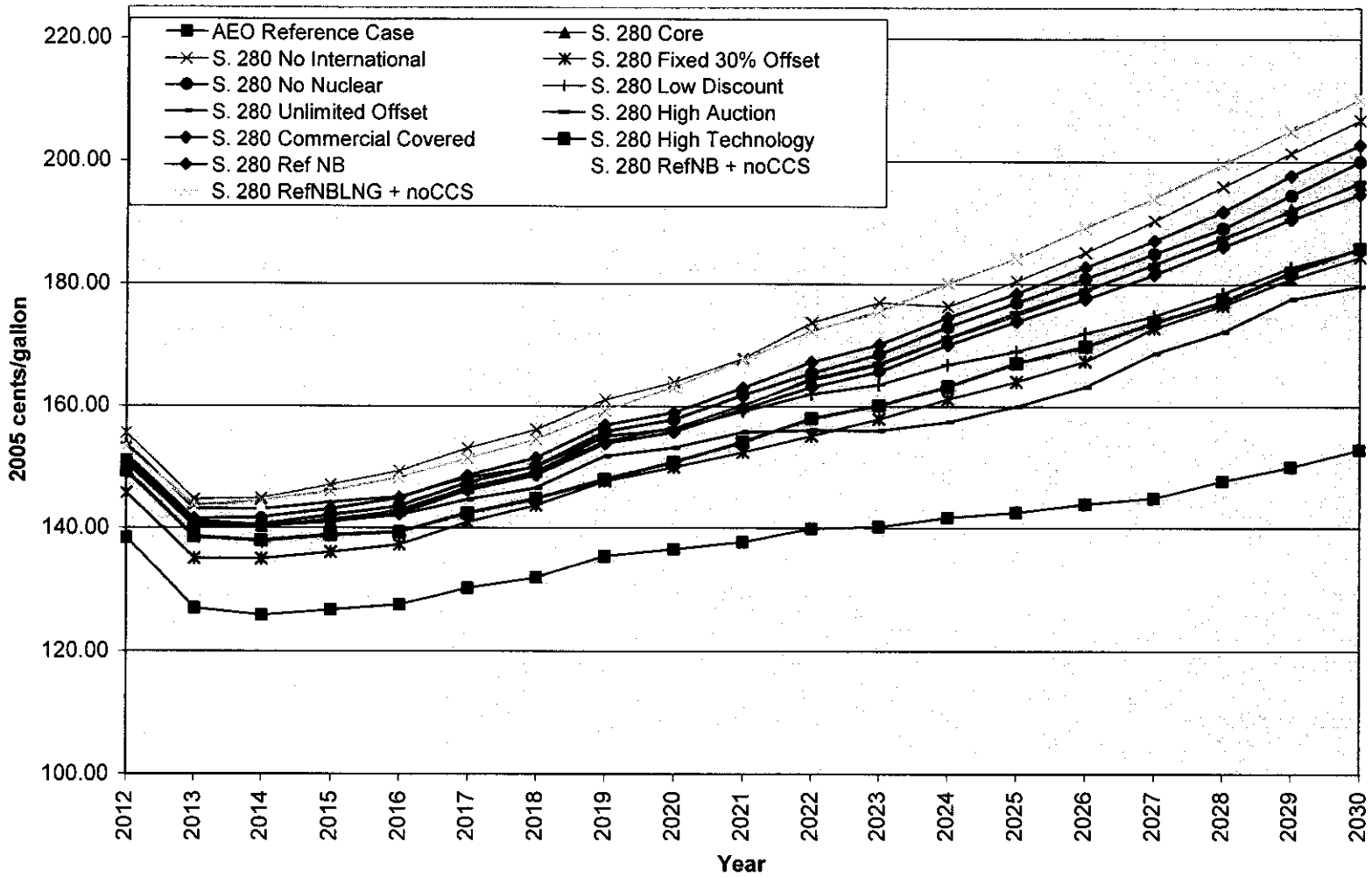


Figure 7-10
Distillate Fuel Oil Price Projections for AEO2007 Reference Case and EIA Analysis of S.280
(Delivered 2005 Cents/Gallon - Electric Power Sector, Including Cost of CO_2 Allowances for S.280 Cases)

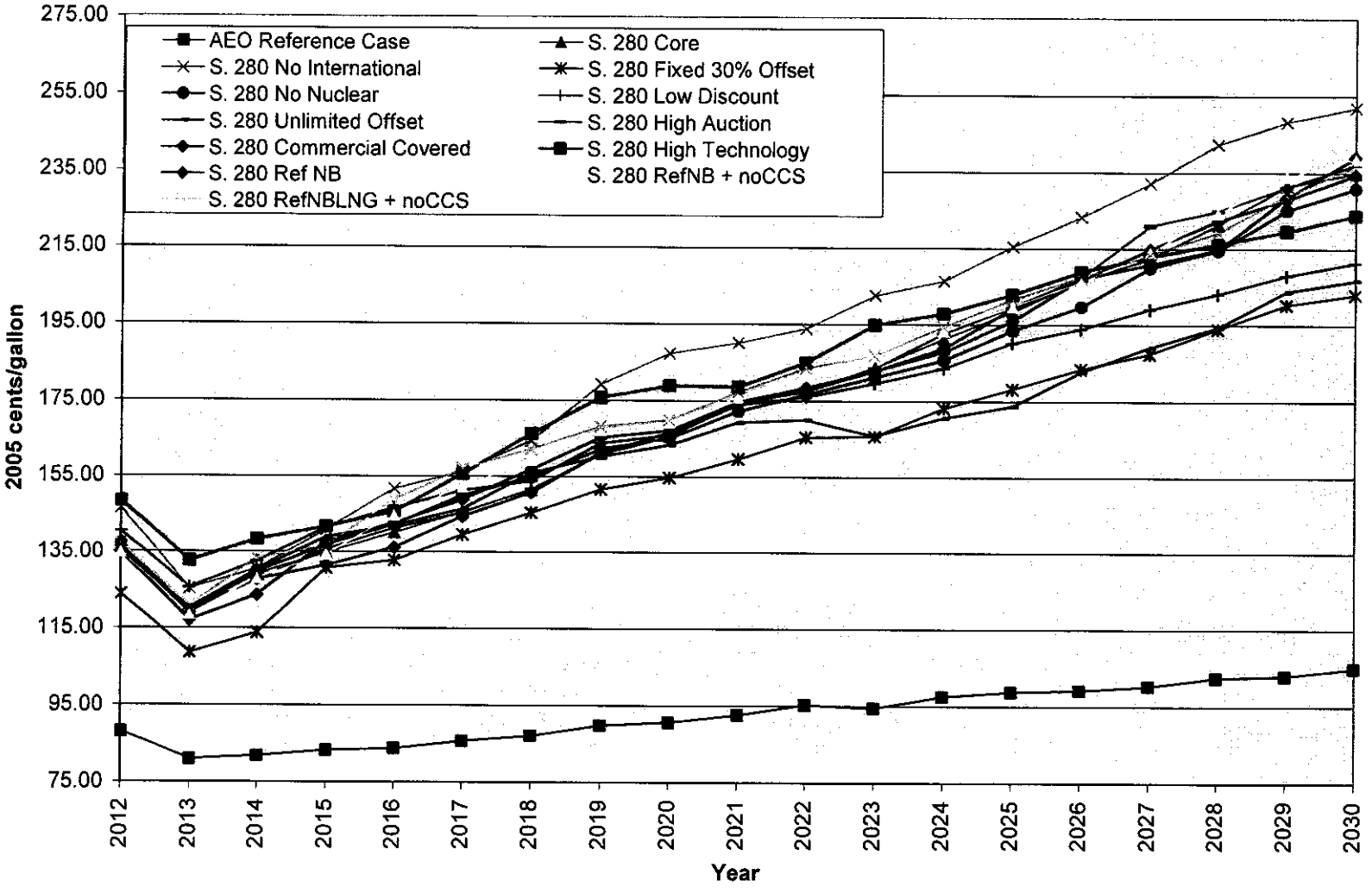


Figure 7-11
Residual Fuel Oil Price Projections for AEO2007 Reference Case and EIA Analysis of S.280
(Delivered 2005 Cents/Gallon - Electric Power Sector, Including Cost of CO_2 Allowances for S.280 Cases)

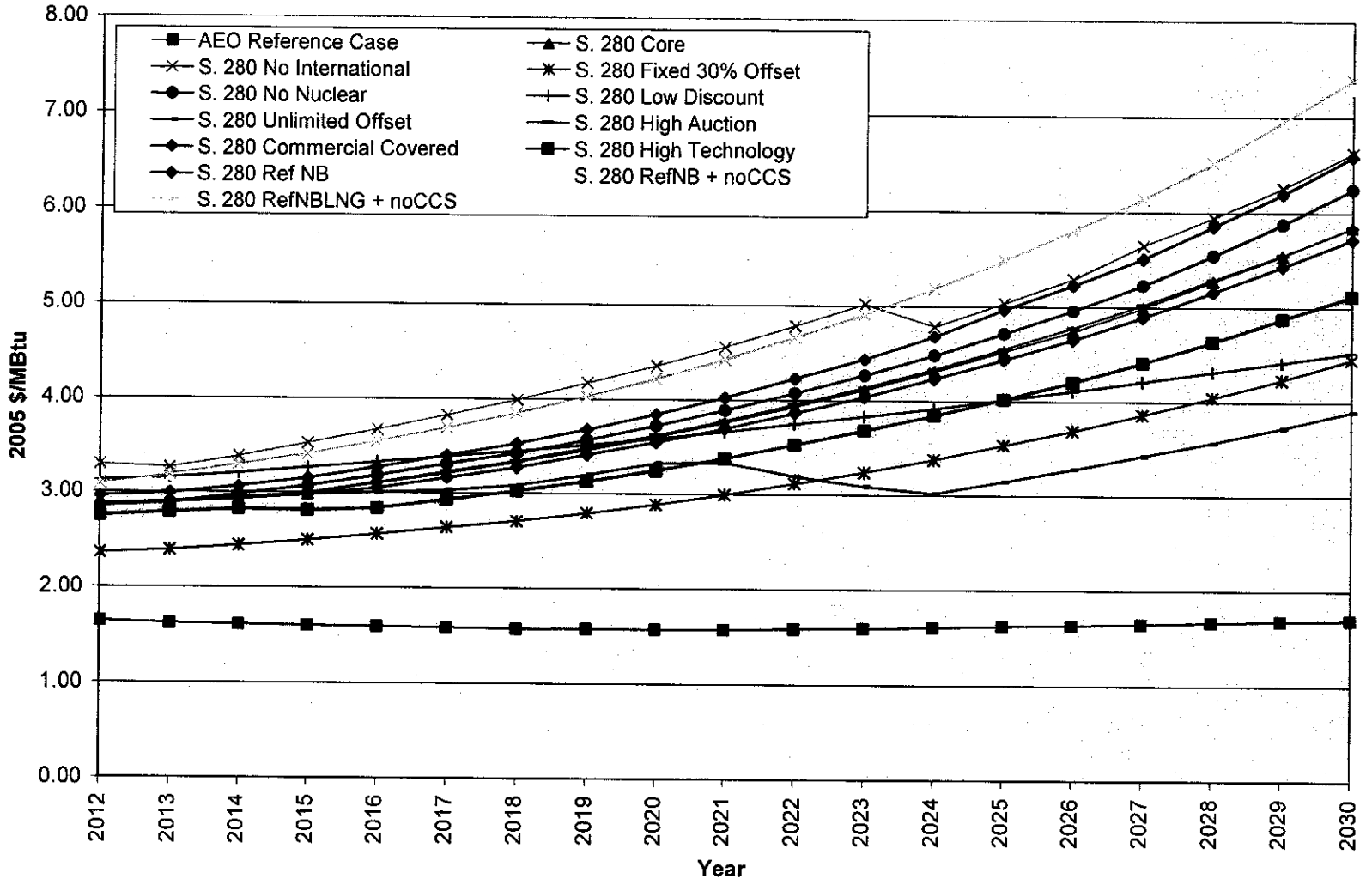


Figure 7-12
Coal Price Projections for AEO2007 Reference Case and EIA Analysis of S.280
(Delivered 2005 $/MBtu - Electric Power Sector, Including Cost of CO_2 Allowances for S.280 Cases)

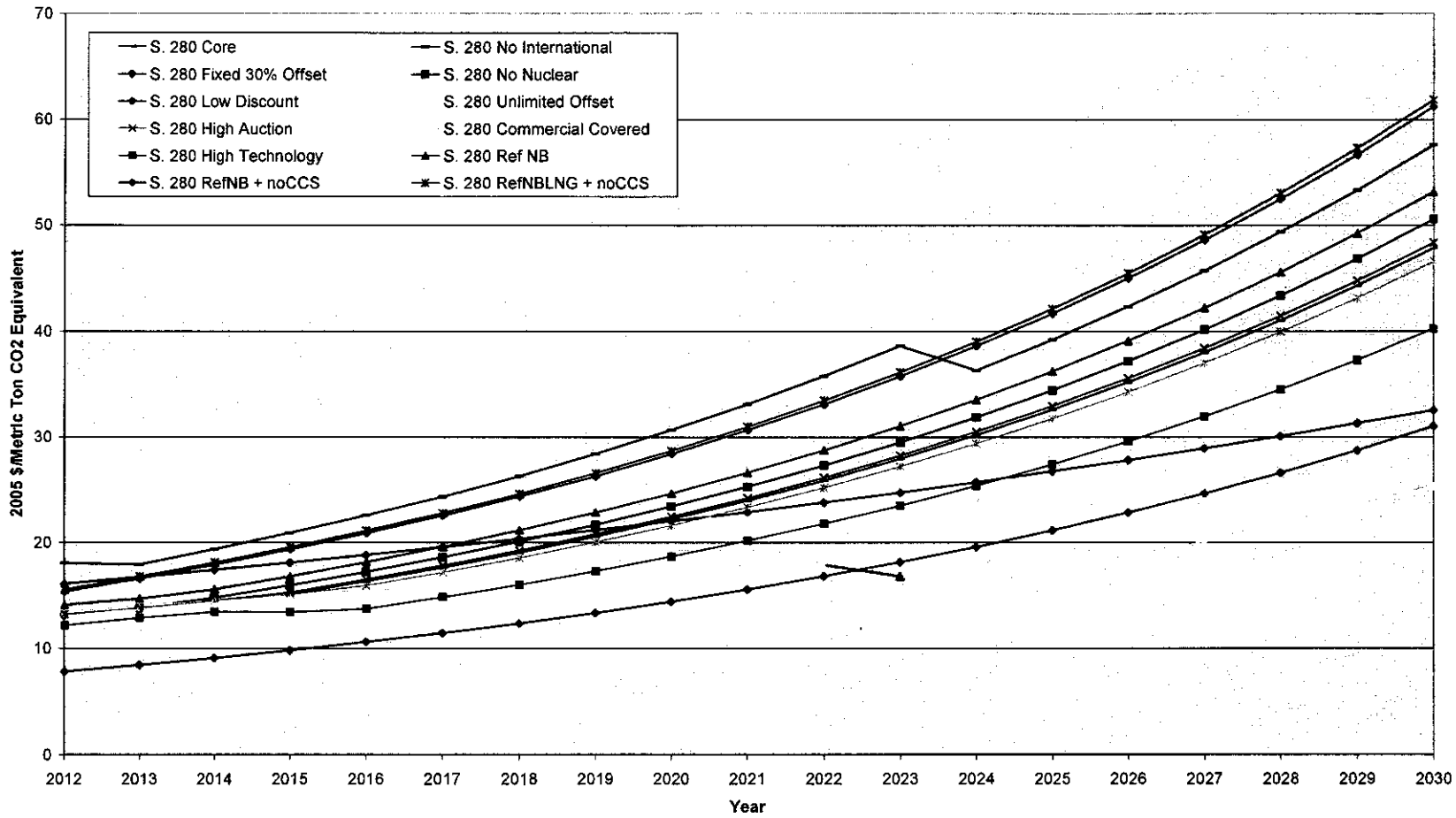


Figure 7-13
CO_2 Emissions Allowance Price Projections from EIA Analysis of S.280 (2005 $/Metric Ton CO_2 Equivalent)

An analysis of Tables 7-10 through 7-14 (supplemented by Figures 7-9 through 7-13) shows that projected impacts on natural gas prices and corresponding CO_2 emissions allowance price projections differ depending upon the policy cases considered in the EIA analysis of S.280. When compared across the nine policy cases, the projected natural gas, fuel oil, and coal prices (including the cost of CO_2 emissions allowances) and the annual projections of CO_2 emissions allowance prices corresponding to the S.280 Core case fall within (and towards the upper end of) the boundaries set by the other eight policy cases.

7.8 Consideration of EIA Analysis of Senate Bill 280

As discussed in Section 7.7, the EIA developed an analysis of potential economic impacts of the *Climate Stewardship and Innovation Act of* 2007, which was introduced to the 110th US Congress as S.280 on January 12, 2007 by Senator Lieberman (for himself and Senator McCain, Senator Lincoln, Senator Snowe, Senator Obama, Senator Collins, and Senator Durbin). The EIA's analysis included projections of natural gas, fuel oil, and coal prices, along with projected prices for CO_2 emissions for 12 various policy cases involving different assumptions related to the structure of how S.280 may be implemented if ultimately enacted by Congress. The fuel price projections, as well as the CO_2 emissions allowance price projections, for each of the 12 policy cases are presented throughout Section 7.7. Analysis of the various policy cases and corresponding fuel and emissions allowance prices indicates that the S.280 Core Case (as defined by the EIA) reflects projected impacts on fuel and emission allowance prices that fall within the boundaries set by the other 11 policy cases. These relative projected impacts, taken in combination with the S.280 Core Case being considered by the EIA as representative of the primary policy case, resulted in the selection of the S.280 Core Case for further analysis in this Application.

The natural gas, fuel oil, and coal price projections for the S.280 Core Case presented in Section 7.7 include the annual costs of CO_2 emissions allowance prices, consistent with the presentation of data in EIA's analysis of S.280. Table 7-15 presents the natural gas, fuel oil, and coal price projections from the S.280 Core Case, excluding the annual costs of CO_2 emissions allowance prices as projected by the EIA.

Also presented in Table 7-15 are projections of natural gas, fuel oil, and coal prices, including the EIA's projected annual costs of CO_2 emissions allowances for the S.280 Core Case. It should be noted that these natural gas and fuel oil price projections differ from those presented in Section 7.7 because the natural gas, fuel oil, and coal prices presented in Table 7-15 are in constant 2005 dollars per MBtu, while those presented in Section 7.7 are in constant 2005 dollars per mcf for natural gas and constant 2005 cents per gallon for fuel oil.

Table 7-15
S. 280 Core Case Natural Gas, Fuel Oil, and Coal Price Projections
Compared to Non-Adjusted Fuel Price Forecasts (2005 $/MBtu)

Year	Natural Gas		Distillate Fuel Oil		Residual Fuel Oil		Coal	
	Including Costs of CO_2 Emissions Allowances	Excluding Costs of CO_2 Emissions Allowances	Including Costs of CO_2 Emissions Allowances	Excluding Costs of CO_2 Emissions Allowances	Including Costs of CO_2 Emissions Allowances	Excluding Costs of CO_2 Emissions Allowances	Including Costs of CO_2 Emissions Allowances	Excluding Costs of CO_2 Emissions Allowances
2012	6.40	5.70	10.87	9.92	9.13	8.10	2.86	1.62
2013	6.14	5.40	10.14	9.14	7.98	6.90	2.89	1.59
2014	6.17	5.40	10.11	9.07	8.62	7.50	2.93	1.57
2015	6.11	5.31	10.17	9.08	9.00	7.83	2.98	1.56
2016	6.23	5.37	10.30	9.12	9.35	8.08	3.09	1.56
2017	6.42	5.49	10.56	9.29	9.72	8.35	3.20	1.55
2018	6.40	5.40	10.76	9.38	10.10	8.62	3.32	1.54
2019	6.47	5.39	11.17	9.69	10.76	9.15	3.45	1.52
2020	6.54	5.37	11.27	9.67	11.12	9.39	3.59	1.51
2021	6.64	5.38	11.55	9.82	11.61	9.75	3.75	1.50
2022	6.85	5.48	11.84	9.97	11.86	9.84	3.93	1.50
2023	7.01	5.54	12.02	10.00	12.26	10.09	4.11	1.49
2024	7.10	5.51	12.33	10.15	12.77	10.42	4.31	1.48
2025	7.29	5.57	12.61	10.25	13.25	10.71	4.52	1.46
2026	7.46	5.60	12.89	10.35	13.80	11.06	4.74	1.44
2027	7.55	5.55	13.21	10.46	14.18	11.22	4.99	1.43
2028	7.67	5.50	13.51	10.54	14.79	11.59	5.27	1.43
2029	7.85	5.51	13.86	10.65	15.46	12.00	5.54	1.40
2030	8.15	5.62	14.16	10.69	15.68	11.95	5.85	1.37

7.8.1 S.280 Core Case Fuel Prices Delivered to the FRCC Region

Projections of natural gas, fuel oil, and coal prices for the FRCC region that consider the potential impacts of CO_2 regulations, consistent with the EIA S.280 Core Case, were developed for analysis in this Application. To develop such fuel price forecasts, the AEO2007 Reference Case fuel prices delivered to the US electric power sector were analyzed and compared to the corresponding S.280 Core Case fuel price projections presented in Table 7-15 (excluding the costs of CO_2 emissions allowances, which are accounted for elsewhere in the economic analysis included in this Application). Annual percent differentials between the AEO2007 Reference Case fuel price projections and corresponding fuel price projections from the S.280 Core Case were calculated for natural gas, distillate and residual fuel oil, and coal. The annual price differentials were applied to the natural gas, distillate and residual fuel oil, and coal price projections for the FRCC region (shown in Tables 7-1 and 7-2) to develop projections of fuel prices delivered to the FRCC region that reflect the potential impact of S.280 related to the regulation of CO_2 emissions (consistent with the EIA S.280 Core Case). The resulting projections of fuel prices for 2012 through 2030, in constant 2005 dollars per MBtu, specific to the FRCC region are presented in Table 7-16. Prior to 2012, the natural gas, fuel oil, and coal price projections presented in Tables 7-1 and 7-2 remain unaffected, since the analysis assumes that CO_2 regulations will begin in 2012.

7.8.2 Carbon Dioxide Emissions Allowance Prices

The EIA's projected CO_2 emissions allowance prices corresponding to the S.280 Core Case are presented in Table 7-17. The EIA developed its projections of CO_2 emissions allowance prices in constant 2005 dollars per metric ton, which are shown in the second column of Table 7-12 and match those presented previously in Section 7.7 (Table 7-14). The annual CO_2 emissions allowance price projections in constant 2005 dollars per short ton are shown in the third column of Table 7-17.

Table 7-16
Forecast of Fuel Prices Delivered to FRCC Considering
Potential Impact of S.280 (EIA S.280 Core Case)
(2005 $/MBtu)

Year	Natural Gas	Distillate Fuel Oil	Residual Fuel Oil	Low Sulfur Central Appalachian Coal
2012	$5.79	$10.15	$8.23	$2.86
2013	$5.54	$9.33	$7.31	$2.85
2014	$5.53	$9.26	$7.74	$2.86
2015	$5.42	$9.27	$8.01	$2.83
2016	$5.54	$9.34	$8.22	$2.84
2017	$5.66	$9.52	$8.50	$2.80
2018	$5.65	$9.62	$8.74	$2.71
2019	$5.69	$9.88	$9.25	$2.64
2020	$5.67	$9.86	$9.49	$2.61
2021	$5.67	$10.02	$9.82	$2.57
2022	$5.78	$10.17	$9.84	$2.60
2023	$5.81	$10.20	$10.12	$2.58
2024	$5.83	$10.37	$10.38	$2.56
2025	$5.90	$10.48	$10.65	$2.53
2026	$5.93	$10.57	$11.03	$2.47
2027	$5.89	$10.70	$11.13	$2.44
2028	$5.84	$10.77	$11.53	$2.43
2029	$5.82	$10.88	$11.95	$2.38
2030	$5.91	$10.95	$11.95	$2.35

Table 7-17
Projected CO_2 Emission Allowance Prices
EIA S.280 Core Case

Year	2005 $/Metric Ton	2005 $/Short Ton
2012	13.21	11.98
2013	13.86	12.57
2014	14.44	13.10
2015	15.09	13.69
2016	16.29	14.78
2017	17.60	15.96
2018	19.00	17.24
2019	20.52	18.62
2020	22.17	20.11
2021	23.94	21.72
2022	25.85	23.45
2023	27.92	25.33
2024	30.16	27.36
2025	32.57	29.55
2026	35.17	31.91
2027	37.99	34.46
2028	41.03	37.22
2029	44.31	40.20
2030	47.85	43.41

8.0 Natural Gas Transportation

The Cane Island site is served by two separate existing natural gas pipelines owned by Florida Gas Transmission Company (FGT) and Gulfstream Natural Gas System, LLC (Gulfstream). These natural gas transportation supply systems, along with additional natural gas pipeline systems that serve the state of Florida as a whole, are discussed in this section.

8.1 Florida Gas Transmission

FGT, a subsidiary of Citrus Corporation (Citrus Corp.), operates a 5,000 mile natural gas pipeline system that extends from south Texas to south Florida with a current mainline capacity of 2.1 billion cubic feet (Bcf) per day. FGT offers natural gas transportation service for third parties. Citrus Corp is 50 percent owned by Southern Union Company (NYSE:SUG) and 50 percent owned by El Paso Corporation (NYSE:EP). The FGT system is illustrated in Figure 8-1.



Figure 8-1
FGT System
(Source: http://www.crosscountryenergy.com/about/fgt.shtml)

8.1.1 Existing FGT System

The FGT pipeline system transports natural gas to cogeneration facilities, electric utilities, independent power producers, municipal generators, and local distribution companies through a 5,000 mile natural gas pipeline that extends from south Texas to south Florida. It delivers 2.1 Bcf of natural gas per day to more than 240 delivery points, consisting of more than 50 natural gas fired electric generation facilities. FGT's total receipt point capacity is in excess of 3.0 Bcf per day and includes interconnects with 10 interstate and 10 intrastate pipelines to facilitate receiving supplies of natural gas into its pipeline system. The pipeline has extensive access to diverse natural gas supplies, including the offshore Gulf of Mexico region.

The pipeline enters the Florida Panhandle in northern Escambia County and runs easterly to a point in southwestern Clay County, where the primary pipeline corridor turns southerly to pass west of the Orlando area. The mainline corridor then turns in a southeasterly direction to a point in southern Brevard County, where it turns south generally paralleling Interstate Highway 95 to the Miami area. A major lateral line (the St. Petersburg Lateral) extends from a junction point in southern Orange County westerly to terminate in the Tampa, St. Petersburg, and Sarasota area. A major loop corridor (the West Leg Pipeline) branches from the mainline corridor in southeastern Suwannee County to run southward through western Peninsular Florida to connect to the St. Petersburg Lateral system in northeastern Hillsborough County. Numerous lateral pipelines extend from the major corridors to serve major local distribution systems and industrial/utility customers.

FGT has completed numerous system expansions over the recent years since its major Phase III expansion in 1995. Below is a summary of these projects that were of sufficient significance to warrant a "phase" designation:

- Phase IV expansion project completed in May 2001. This project consisted of approximately 205 miles of various diameter pipelines, additional compression totaling 48,570 horsepower, and four new delivery points (including three new measurement stations) in the states of Mississippi, Alabama, and Florida. The Phase IV expansion added incremental mainline capacity to FGT's existing pipeline system of approximately 272,000 MBtu per day at an estimated cost of $268 million.
- Phase V expansion project completed in May 2003. This project consisted of approximately 166 miles of pipeline and 133,000 horsepower of compression, including three new compressor stations, to its existing system in the states of Mississippi, Alabama, and Florida. The Phase V expansion added incremental mainline capacity to FGT's existing pipeline system of approximately 428 million cubic feet (MMcf) per day at an estimated cost of $452 million.

- Phase VI expansion project completed in November 2003. This project consisted of approximately 33 miles of pipeline and 18,600 horsepower of compression to its existing system in the states of Louisiana, Mississippi, Alabama, and Florida. The Phase VI expansion added incremental mainline capacity to FGT's existing pipeline system of approximately 121 MMcf per day at an estimated cost of $100 million.
- Phase VII expansion project construction completed in May 2007, except for modifications to a compressor station that were completed in December 2007. This project consisted of approximately 33 miles of pipeline and 9,800 horsepower of compression to its existing system in the state of Florida. The Phase VII expansion added incremental mainline capacity to FGT's existing pipeline system of approximately 160 MMcf per day at an estimated cost of $104 million. This expansion will provide access to an additional natural gas supply from the SNG LNG Elba Island LNG import terminal near Savannah, Georgia.

8.1.2 Market Area Pipeline Interconnections

FGT's pipeline system has three pipeline interconnections that are capable of making natural gas deliveries within the state of Florida. FGT has two interconnections with Gulfstream: one interconnection in Osceola County and the other in Hardee County. Both of these interconnections offer delivery of Gulf Coast supplies directly into FGT's system in its market area of central Florida. Southern Natural Gas (SNG) also has an interconnection with FGT in Duval County at Cypress. This interconnection allows the delivery of natural gas off of the SNG system, the majority of which comes from SNG's Elba Island LNG import terminal located in Savannah, Georgia.

8.1.3 Planned FGT System Expansions

As presented previously in the summary of system expansions, FGT has continuously added pipeline capacity to increase its ability to offer firm transportation service into the state of Florida and meet the growing demand for natural gas within the state. FGT conducted an Open Season ending on February 15, 2008, for a proposed Phase VIII expansion project. On February 11, 2008, FGT announced that Florida Power & Light Company (FPL) had agreed to become the anchor shipper of a proposed natural gas pipeline expansion project through a 25 year service agreement for 400 MMcf per day of capacity. FGT intends to seek regulatory approval to build the proposed Phase VIII system expansion at an estimated cost of $2 billion to provide approximately 800 MMcf per day of increased natural gas capacity to Florida. The proposed Phase VIII

expansion includes construction of approximately 500 miles of additional large diameter pipeline and the installation of approximately 170,000 horsepower of additional compression. The Phase VIII expansion will increase the capacity of FGT's mainline facilities from the Mobile Bay, Alabama, area to southern Florida to provide additional firm transportation service capacity throughout Florida. Pending regulatory approvals, FGT is anticipating a spring 2011 in-service date for the project. The FPL commitment will help ensure that the Phase VIII expansion will be built, filling 50 percent of the incremental capacity that is planned.

During the Open Season period, FMPA submitted a request for firm capacity of 30,000 MBtu per day to serve Cane Island 4. This submittal was a nonbinding request for capacity. Subsequent discussions have occurred where FGT required a binding volume commitment from FMPA to meet its material commitment schedule. FMPA was not prepared to make a binding commitment in the timeline necessary to meet this requested deadline. As a result, FGT formally withdrew its offer of capacity from the Phase VIII expansion on May 1, 2008.

8.1.4 Projected FGT Natural Gas Transportation Costs

FGT's Phase VIII Open Season states that the Phase VIII expansion project will provide incremental firm natural gas transportation service under a proposed FTS-3 Rate Schedule, the details of which have not yet been released. FGT has provided an estimate of the demand charge component for incremental firm transportation capacity from the eastern area of Zone 3 to Cane Island under a proposed new FTS-3 Rate Schedule on a confidential basis. That estimated firm incremental transportation cost has been used in the economic evaluations in this Application. Commodity and fuel rates are projected to be comparable to the current FTS-2 rate structure, with minimal change. A stipulation in the Open Season was that all transportation arrangements entered into as a part of this expansion would be for a minimum commitment of 25 years.

8.2 Gulfstream

Gulfstream is a joint development between Williams and Spectra Energy. The Gulfstream system consists of a 691 mile pipeline that was placed in service in May 2002; the pipeline is illustrated on Figure 8-2.

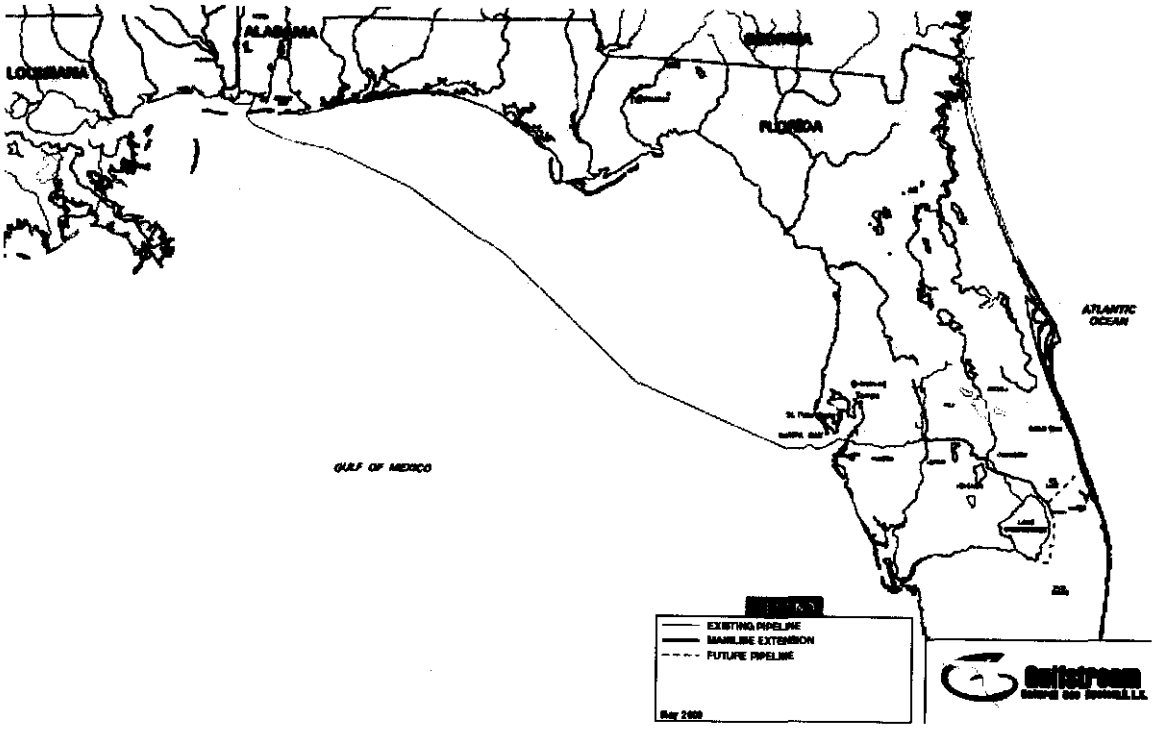


Figure 8-2
Gulfstream System
(Source: http://www.gulfstreamgas.com/images/gulfstream05_03.pdf)

8.2.1 Existing Gulfstream System

The Gulfstream pipeline originates near Pascagoula, Mississippi, and Mobile, Alabama, and crosses the Gulf of Mexico with more than 430 miles of 36 inch diameter pipeline to Manatee County, Florida. Once onshore, 240 miles of 30 inch to 36 inch diameter mainline crosses Manatee, Hardee, Polk, Osceola, Highlands, Okeechobee, and Martin counties in Florida. Gulfstream can serve customers on both the east and west coasts of Florida, as well as the interior of the peninsula. The Gulfstream system went into service with a capacity of 1.1 Bcf per day of gas. The initial subscribed capacity was less than 200 MMBtu/s, leaving approximately 900 MBtu per day of capacity available for new and existing customers. The pipeline was constructed to serve existing and prospective electric generation and industrial projects in central and southern Florida.

Gulfstream has undertaken several system extensions/expansions since its initial in-service date of May 2002. These system expansions were projects designed to connect Gulfstream to facilities located remotely from its initial routing. These project expansions are as follows:

- The Phase II extension of the Gulfstream pipeline was placed into service in February 2005. The 110 mile extension was designed to provide 350,000 dekatherms per day of firm natural gas transportation service for

FPL's Martin and Manatee power plant expansions. The new pipeline traverses five counties: Polk, Hardee, Highlands, Okeechobee, and Martin.

- The Phase III project is scheduled for completion in July 2008. The Phase III project extends the Gulfstream pipeline approximately 35 miles south from Martin to Palm Beach County (approximately 8.8 miles in Martin County and approximately 26.2 miles in Palm Beach County). The extension is designed to deliver 345,000 MBtu per day of firm natural gas transportation service for FPL's West County Energy Center. This volume commitment used the remaining system capacity of 1,095,000 MBtu per day, up from the previous utilized level of 753,000 MBtu per day.
- The Phase IV expansion project is scheduled for completion in January 2009. The Phase IV project will add compression and extend the pipeline to a new market, increasing Gulfstream's mainline capacity from 1.1 Bcf per day to 1.25 Bcf per day by early 2009. The Phase IV expansion project will include construction of approximately 17.5 miles of 20 inch diameter pipeline, as well as the installation of an additional 45,000 horsepower of compression: 15,000 horsepower at an existing compressor station in Coden, Alabama, and 30,000 horsepower at a new station in Manatee County, Florida. The Phase IV expansion project will increase Gulfstream's system capacity by approximately 155,000 MBtu per day to a total of 1.25 Bcf per day.

8.2.2 Market Area Pipeline Interconnections

Gulfstream's pipeline system has two pipeline interconnections that are capable of delivering natural gas within the state of Florida. FGT has two interconnections with Gulfstream, one in Osceola County and one in Hardee County. Both of these interconnections offer delivery of Gulf Coast supplies directly into Gulfstream's system via displacement in the system's market delivery area of central Florida.

8.2.3 Planned Gulfstream System Expansions

Gulfstream conducted an Open Season from June 1 to August 31, 2007, to gauge market interest in an expansion of its existing natural gas pipeline system to serve Florida's rapidly growing natural gas market. The expansion will be designed for up to 750,000 MBtu per day of incremental firm transportation service. The new service from the mainline expansion is anticipated to be available beginning in late 2011.

During the Open Season period, FMPA submitted a request for a volume of 20,000 MBtu per day of firm capacity to serve Cane Island 4. This submittal was a non-binding request for capacity. Subsequent discussions are anticipated to define the specific details of the arrangement for inclusion into a binding Precedent Agreement between FMPA and Gulfstream.

Prior to formally executing a Precedent Agreement, FMPA will analyze each of the possible pipeline options available for serving the Cane Island facilities and will examine the economic and operational benefits of each. As a result, the actual transportation capacity agreed to in the Precedent Agreement may vary from that requested in the Open Season.

8.2.4 Projected Gulfstream Natural Gas Transportation Costs

Gulfstream has indicated that the ultimate project configuration will be determined once a final commitment has been obtained from participating shippers and after subsequent engineering and project development is conducted to optimize the expansion's design. The final transportation rates will be based on the optimized design.

8.3 Cypress Pipeline

Cypress pipeline is a specific section of the Southern Natural Gas (SNG) system, a subsidiary of El Paso Corporation. This pipeline was placed into service on May 1, 2007. The new pipeline provided an incremental 220,000 MBtu per day of takeaway capacity from Elba Island, SNG's LNG facility near Savannah, Georgia. From Elba Island, the 167 mile, 24 inch pipeline extends the SNG system into southern Georgia and northern Florida and interconnects with the FGT system near Jacksonville, Florida. The Cypress pipeline is illustrated on Figure 8-3.

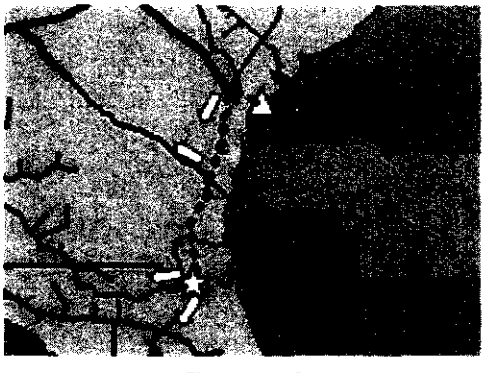


Figure 8-3
Cypress Pipeline
(Source: http://www.elpaso.com/cypresspipeline/default.shtm)

8.3.1 *Planned Cypress Pipeline Expansions*

Currently, there are two planned expansions of the Cypress pipeline:

- Phase 2 will include the addition of 10,350 horsepower of compression at the new compressor station in Glynn County, Georgia; be in service in May 2008. Phase 2 will increase the capacity an additional 116 MBtu per day from 220,000 MBtu per day up to 336,000 MBtu per day.
- Phase 3 will consist of approximately 10 miles of 30 inch diameter pipeline, the addition of 10,350 hp of compression at the new compressor station in Liberty County, Georgia, and an additional 10,350 hp of compression at the new compressor station in Nassau County, Florida. Phase 3 is scheduled for completion by May 2010. Phase 3 will increase the capacity an additional 164 MBtu per day from 336,000 MBtu per day up to a total of 500,000 MBtu per day.

8.4 Projected Availability of Natural Gas Transportation Capacity

As discussed previously, the Florida natural gas transportation system has become increasingly diverse and interconnected. Natural gas transportation providers have a long history of expanding the system to meet the needs of Florida's natural gas transportation customers. With all of the proposed natural gas supply expansion projects under way, FMPA is confident that adequate natural gas transportation capacity will be available to provide reliable service for Cane Island 4. The site being served by both FGT and Gulfstream offers FMPA the opportunity to choose the best transportation capacity option available. Constructing a new generating unit in an area served by two pipelines enhances the reliability of delivering natural gas to Cane Island 4.

9.0 Project Overview

9.1 Description of Project

FMPA's Cane Island 4 will be a 1x1 F class combined cycle unit with a nominal rating of 300 MW at average temperature conditions. The unit will be installed at the existing Cane Island Power Park (CIPP) site located near Intercession City, Florida.

9.1.1 Mode of Operation

Subject to final approval by the Siting Board and the Florida Department of Environmental Protection (FDEP), Cane Island 4 will be permitted for unlimited operation on natural gas in combined cycle mode. The Combustion Turbine Generator (CTG) will have an evaporative cooler to increase warm weather power generation and a steam turbine bypass to the condenser to allow CTG operation if an extended steam turbine generator outage occurs. Cane Island 4 is expected to operate in a cycling and intermediate mode.

9.1.2 Combustion Turbine Generator

The CTG will be a GE PG7241FA enhanced combustion turbine with modulating inlet guide vanes. The CTG will have enclosures for outdoor installation and will include the following major features:

- Dry low NO_x combustion system.
- Direct connected generator with static excitation.
- Acoustic enclosure for turbine.
- Inlet air filter system with silencers and evaporative coolers.
- Lube oil systems.
- Static starting system.
- Fire detection/CO_2 fire protection systems.
- Mark VIe control system with remote work station.
- Off-line/on-line water wash system.
- Package electrical and electronics control compartment.

9.1.3 Heat Recovery Steam Generator

The heat recovery steam generator (HRSG) will be installed outdoors and will convert waste heat from the combustion turbine exhaust to steam for use in driving the STG. The HRSG is expected to be a natural circulation, three-pressure, reheat unit with supplemental duct firing by natural gas only to maximize unit output. Cycle operating

pressure will be a nominal 2,100 psig. SCR for NO_x emission control will be included within the HRSG. Space will be included for a possible future carbon monoxide (CO) catalyst. The HRSG will discharge to a metal exhaust stack. A stack damper will be included to minimize heat loss during shutdowns. Two 100 percent capacity condensate pumps and boiler feedwater pumps will be included. Natural gas heating, utilizing HRSG intermediate-pressure feedwater as the heating source during normal operation and an electric heater for startup, will be included.

9.1.4 Steam Turbine Generator

The steam turbine will be a GE A14 tandem-compound single reheat condensing turbine operating at 3,600 rpm. The steam turbine will have one high-pressure section with a nominal 2,100 psig throttle pressure, one intermediate-pressure section, and one low-pressure section. Turbine suppliers' standard auxiliary equipment; lubricating oil system; hydraulic oil system; and supervisory, monitoring, and control systems will be utilized. A surface condenser will be provided for condensing steam from the turbine exhaust and will utilize a recirculating cooling tower system for cooling. The condenser will be designed for full steam flow bypass around the steam turbine. Provisions for installation of a blanking plate will be included to allow isolation of the steam turbine from the condenser. A single synchronous generator will be included that will be direct coupled to the steam turbine. Generator suppliers' standard auxiliary equipment; supervisory, monitoring, and control systems; and a static excitation system will be utilized. The steam turbine will be provided with enclosures as required for outdoor installation.

A safe shutdown generator will be provided to supply power to shut down and maintain the plant in a safe condition when plant auxiliary power is lost. The engine generator will use diesel as fuel.

9.1.5 Cooling Tower

A multiple cell, mechanical draft, counterflow cooling tower will be used for plant cooling. The cooling tower will be of fiberglass construction and installed on a reinforced concrete basin that will include a pump intake structure housing two 50 percent capacity circulating water pumps and one 100 percent capacity auxiliary cooling water pump. A circulating water chemical feed system also will be included. The cooling tower will be equipped with high efficiency drift eliminators.

9.1.6 Air Quality Control

Cane Island 4 will be subject to FDEP's Prevention of Significant Deterioration (PSD) permitting program, which requires Best Available Control Technology (BACT) for emissions of various pollutants. This concept has been coupled with the selection of a combined cycle process utilizing an advanced combustion turbine. Compared to more conventional simple cycle generating plants, combined cycle units have lower heat rates and, therefore, generate more electrical output (megawatts) per unit of fuel consumed. As a result, air pollutant emissions per megawatt output are minimized. Pollution prevention also is incorporated into the project design by the use of natural gas, which minimizes emissions of SO_2 and particulate matter. In addition, advanced dry low-NO_x combustion technology will be used to minimize NO_x emissions while ensuring that CO and volatile organic compounds emissions are within accepted limits. Moreover, SCR will be installed to further reduce NO_x emissions. Taken together, these design features will make Cane Island 4 one of the most efficient and lowest emissions power plants in the state of Florida.

9.1.7 Control System

The unit will be designed for control through a plant distributed control and information system (DCIS). A Mark VIe control system for control of the turbine will also be included. The DCIS control screens will be located in the existing main plant control room in the plant administration/control building.

9.1.8 Water Use

Water for cooling tower makeup is expected to be reclaimed water (treated wastewater). Reclaimed water will be supplied from the Toho Water Authority via an existing pipeline. In addition, four new onsite wells will be provided for backup cooling tower makeup water supply. It is expected that a maximum of approximately 3.0 million gallons per day (mgd) will be required. Average cooling water makeup is expected to be about 2.4 to 2.5 mgd, based on 24 hour per day operation.

Service water, evaporative cooler makeup water, potable water, and fire protection water will be supplied from the existing CIPP service water system. This system will provide chlorinated well water from existing onsite wells plus one new well. Fire protection water and service water will be stored onsite in new fire water/service water storage tanks. The new fire protection water system will include two new fire water storage tanks to provide two independent dedicated fire water supply sources, two fire water pumps, a hydrant system, dry-pipe sprinkler or foam system for the steam turbine generator lube oil piping, and other fire protection systems in accordance with National Fire Protection Association (NFPA) recommendations. The new system will

also connect with the existing CIPP fire protection system. Two 500,000 gallon combined service water and fire water storage tanks, each with a reserve capacity of 300,000 gallons dedicated to fire water, will be installed. Two new fire water pumps will be included, each one capable of supplying 2,000 to 2,500 gallons per minute (gpm) of water to the systems.

Demineralized water will be provided from the existing water treatment system for steam cycle makeup. A new demineralized water tank will be installed.

9.1.9 Project Process Wastewaters

There will be five major sources of wastewater: sanitary waste, oil/water separator effluent, cooling tower blowdown, treated chemical wastewaters, and evaporative cooler blowdown. Sanitary wastes will be routed to the existing site septic system. Oil/water separator effluent will be directed to an onsite percolation pond. Other wastewaters, consisting primarily of cooling tower blowdown, will be returned to the Toho Water Authority pipeline.

9.1.10 Storm Water Management

The existing CIPP Unit 3 storm water management system will be expanded to handle Unit 4. Storm water system design will be in accordance with FDEP, South Florida Water Management District (SFWMD), and Osceola County requirements. Storm water runoff will be collected in an onsite detention pond for percolation into the groundwater.

9.1.11 Transmission Interconnection

The project will interconnect to the existing CIPP substation. The CIPP substation is connected to the KUA, OUC, TECO, and PEF 230 kV transmission systems through four existing transmission lines. The CTG and STG will each connect to separate 18 kV/230 kV generator step-up transformers. The CTG and the STG will each have generator breakers. Auxiliary power will be provided by auxiliary transformers connected to each generator's 18 kV isolated phase bus duct. The CIPP 230 kV substation will be modified and expanded by one bay to interconnect the CTG and STGs via a collector bus. Existing onsite transmission lines will be rerouted to accommodate the new unit.

9.1.12 Site Design Conditions

Table 9-1 presents the conceptual design conditions for the project site.

Table 9-1
Conceptual Design Conditions for the Project Site

Condition	Value or Range	Reference
Maximum Temperature Coincident Relative Humidity	102° F 33%	National Climatic Data Center
Minimum Temperature Coincident Relative Humidity	19° F 58%	National Climatic Data Center
Average Temperature Coincident Relative Humidity	73° F 80%	National Climatic Data Center
Wind Loading	Basic Wind Speed: 110 mph, Wind-Borne Debris Region, Importance Factor (Iw): 1.15, Exposure C	ASCE 7-05
Seismic Zone	Not applicable	FBC does not consider seismic loads for building codes.
Site Elevation	Average 82 feet above msl	Site Arrangement Drawing
Location	Outdoors, Corrosive Environment	Site Arrangement Drawing

9.1.13 Site Plan

Figure 9-1 presents the conceptual site plan and shows the arrangement and locations of the major equipment for each unit.

9.1.14 Water Mass Balance

Figure 9-2 presents the preliminary water mass balance for CIPP Unit 4.

9.1.15 Overall One-Line Diagram

Figure 9-3 presents the conceptual electrical one-line diagram showing the arrangement of the electrical interconnections to the existing transmission system and electrical power distribution for the project.

9.1.16 Cycling Design Features

Cane Island 4 will include several design features for cycling load operation. The STG will be selected in combination with the HRSG to provide a reasonable design throttle pressure to ensure satisfactory cycling operation. Because the unit is going to be designed for cycling operation, a nominal throttle pressure of 2,100 psig will be used for design purposes. In comparison to a higher design throttle pressure such as 2,400 psig, a 2,100 psig operating pressure allows reduced wall thicknesses in HRSG drums and piping, thereby reducing thermal stresses and allowing reduced warm-up times. This reduces overall startup time and increases ramp rates when changing loads.

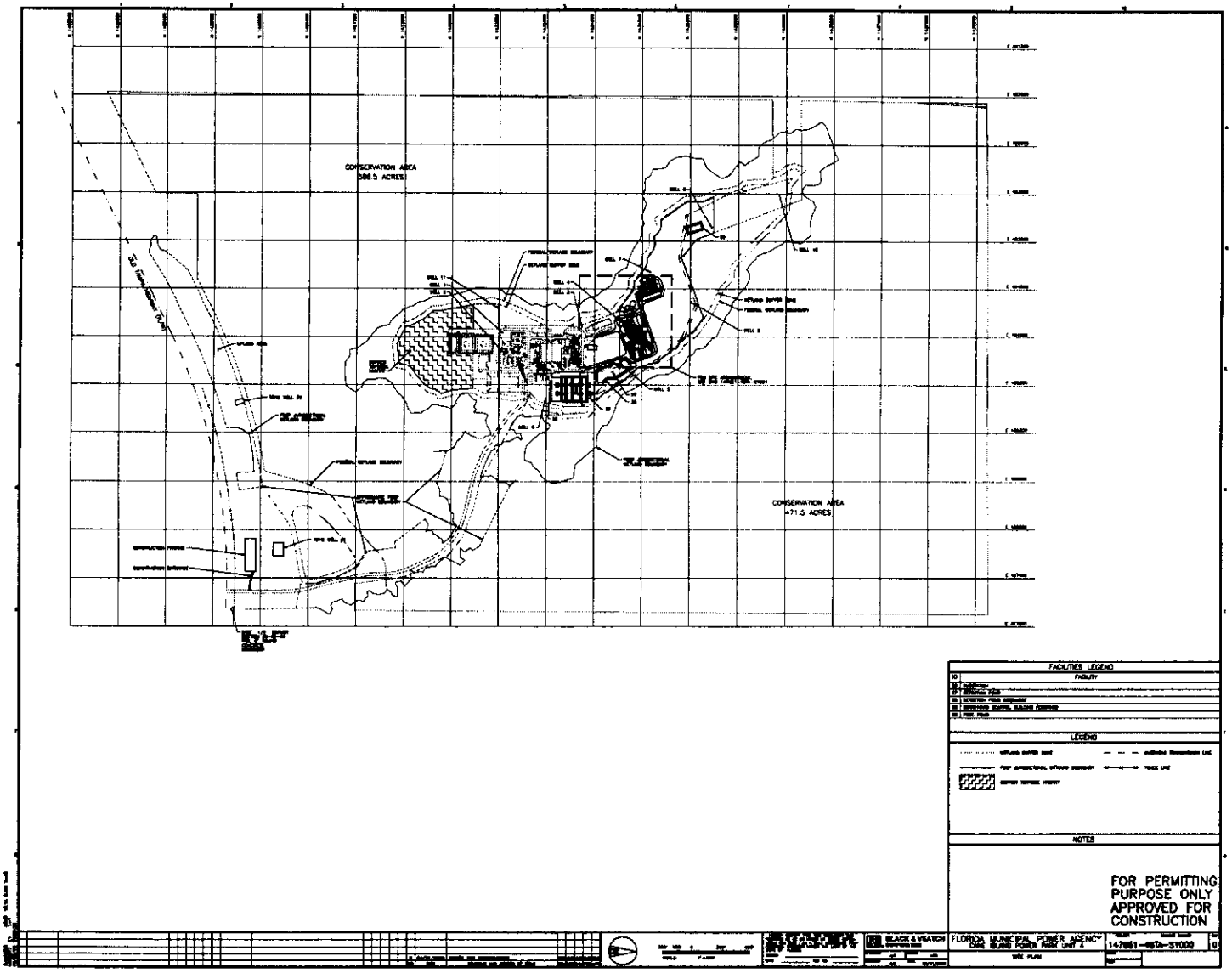


Figure 9-1
Conceptual Site Plan

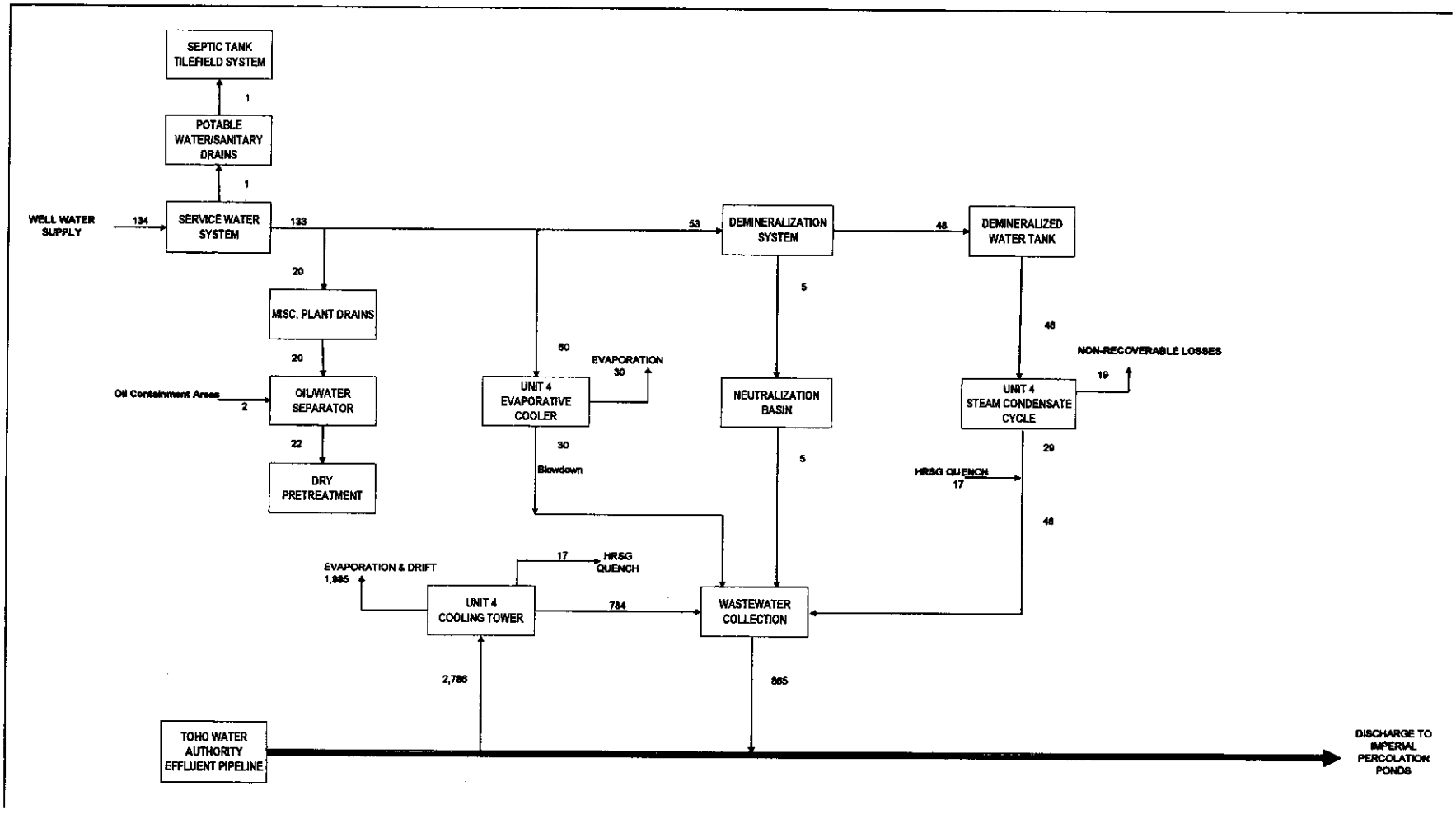


Figure 9-2
Preliminary Water Mass Balance

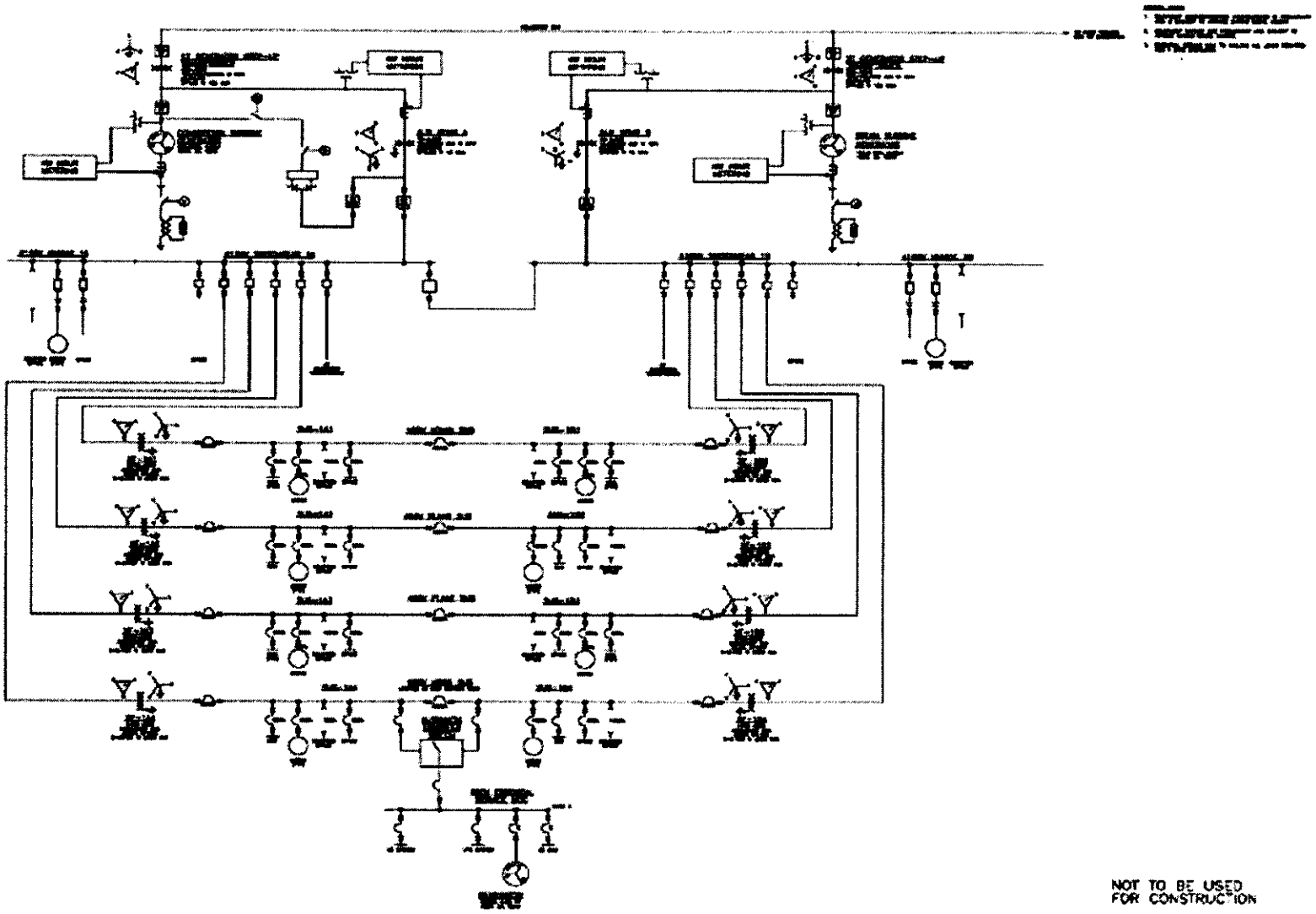


Figure 9-3
Conceptual One-Line Diagram

HRSG design features to facilitate cycling operation will include nozzle arrangement and connections, use of full penetration welds, separation of headers, and use of higher strength drum and header materials to enable thinner wall construction to reduce stress from temperature gradients. Unit design also will include a stack damper for heat retention, automated vent and drain valves to control pressure and drain condensate during shutdowns and startups, a condensate polisher to facilitate condensate quality during startup, and 100 percent bypass systems to enable steam/turbine temperature matching.

9.1.17 Ammonia Systems

Ammonia will be required in the SCR process for NO_x control. Vaporized ammonia will be injected into the combustion turbine exhaust gases before they pass through the catalyst bed, which will be installed in the HRSG. The onsite ammonia system will include unloading facilities, ammonia storage tank, forwarding system, and vaporizing facilities. Aqueous ammonia will be delivered to the site by tanker trucks that will include integral unloading pumps. The aqueous ammonia will be stored as a liquid in a nominal 40,000 gallon tank, which provides for four full tanker truck deliveries. The liquid ammonia will be forwarded to the HRSG, vaporized, and injected upstream of the catalyst.

9.1.18 Capability for Future Expansion

The site will have the capability for the future installation of an additional combined cycle unit. Refer to the Cane Island Site Plan (Figure 9-1), which shows the site with space to the north of Unit 4 to allow installation of one future similar sized combined cycle unit.

9.1.19 Fuel Supply

The fuel for Cane Island 4 will be natural gas. Natural gas is available onsite from existing FGT and Gulfstream pipelines. The existing pipeline pressure is more than adequate for supply to the combustion turbine; therefore, gas compressors will not be included. The quality of the pipeline gas and the final requirements of the combustion turbine manufacturer will be reviewed during detailed design to ensure that any additional conditioning equipment (other than typical heating, pressure control, and filtering type equipment) will not be required.

9.1.19.1 Natural Gas Quantities. Hourly fuel consumption rates will depend on plant load, ambient conditions, and whether supplemental firing is being used. Table 9-2 provides indicative estimates of average fuel consumption rates.

Table 9-2
Indicative Hourly Fuel Consumption Rates

Description of Operating Mode	MBtu/h (HHV)
Average ambient, natural gas fuel, supplemental firing off, full load	1,743
Average ambient, natural gas fuel, supplemental firing on, full load	2,308

9.1.19.2 Natural Gas Transportation, Delivery, and Metering. Natural gas will be regulated, metered, and conditioned onsite. A new meter run, pressure reduction station, and natural gas conditioning equipment will be included. The natural gas conditioning equipment will include a fuel gas scrubber, two coalescing gas filters, and a performance fuel gas heater.

9.2 Project Procurement and Implementation Plan

FMPA will implement the addition of Cane Island 4 to CIPP through purchase of the major rotating equipment and contracts for engineering, procurement, and construction services for the installation of the power block and interfaces with the existing units. KUA will provide the substation modifications required to connect Unit 4 to the CIPP substation.

The CTG and the STG were purchased from GE through an option available under the Treasure Coast Energy Center Unit 1 Combustion Turbine Generator Purchase Order.

A contract or contracts will be executed to provide the project engineering, balance of procurement, construction, and startup. Contracts will be with firms that are experienced and qualified to implement combined cycle projects of the size and complexity of Cane Island 4. Contracts will be released in the spring of 2008 to allow for the procurement of equipment and materials that require long lead times. Equipment lead times have increased significantly in the last year because of world demand for power plant equipment.

9.3 Capital Cost

The capital cost estimate was based on building a new 1x1 7FA combined cycle generating unit at the existing CIPP near Intercession City, Florida. The capital cost estimate includes direct costs for purchased equipment and materials, construction contract costs, and indirect costs. Direct costs include the costs associated with the purchase of equipment, erection, and all contractor services.

Construction costs were developed on the basis of an EPC contract. It was assumed that construction would be performed using a 50 hour work week, with some 60 hour work weeks. Local labor craft rates used included payroll, payroll taxes, and benefits. Construction indirects and construction equipment costs were included in the construction and service contracts portion of the estimate.

Indirect costs associated with construction were included in the base cost estimate. General indirect costs included all necessary services required for checkouts, testing services, and commissioning. Insurance for general liability was included. Contractor engineering, contractor field construction management, technical direction, contingency, profit, equipment transportation costs, startup, and commissioning were also included.

Owner's cost were estimated on the basis of FMPA's experience with other similar projects. These cost items include the following:

- Transmission system upgrades and interconnection lines.
- Project development, preliminary engineering, permitting, and legal costs.
- Consultant engineering and construction management services to act as owner's engineer.
- Rolling stock.
- Initial inventories of furniture, equipment, supplies, and consumables.
- Operating and maintenance (O&M) mobilization.
- Owner's project management and oversight.
- Builder's risk insurance.
- Fuel cost for operational testing.
- Owner's contingency.

Table 9-3 provides a summary of the capital cost estimate.

Table 9-3
Cane Island 4 In-Service Capital Cost Estimate
($000)

Item	
Combustion Turbine/Steam Turbine	48,400
EPC	246,900
Contingency	25,000
Owner's Costs	69,500
Total Project Costs	389,800
Interest During Construction	31,800
Total Installed Capital Cost	421,600

9.4 Operating and Maintenance Cost

O&M costs include fixed and variable costs. Fixed costs are independent of plant operation; variable costs are directly related to the plant operation. The O&M cost estimates were based on the following assumptions:

- Natural gas fuel.
- Cooling tower makeup water provided by the Toho Water Authority, as treated sewage effluent.
- Potable water and service water from the existing service water system, which provides chlorinated water from existing onsite wells.
- A full-time staff of 6 personnel consistent with staffing levels agreed upon by FMPA and KUA.
- An operating profile consisting of up to 200 starts per year and an average capacity factor of 50 percent.

9.4.1 Fixed O&M Costs

Fixed costs include labor, payroll burden, fixed routine maintenance, and administration costs. For Cane Island 4, the fixed costs were estimated to be $4.56/kW per year (2008 dollars), assuming an average annual net output of approximately 307.2 MW.

9.4.2 *Variable O&M*

Variable O&M costs include consumables, chemicals, lubricants, water, and major inspections and overhauls. Major inspection and overhaul costs can be covered under long-term service agreements with the turbine manufacturer, or each overhaul can be subcontracted to the turbine supplier or a third party maintenance provider. As the plant is not staffed to fully perform these major inspections, it was assumed that these will be subcontracted to the turbine supplier or a third party O&M provider. Variable O&M costs vary as a function of plant generation. The variable O&M cost for Cane Island 4 was estimated to be $3.30/MWh in 2008 dollars.

9.5 Heat Rate

Table 9-4 summarizes the anticipated plant performance on the basis of the heat balances developed for various operating conditions for the project. The heat balances and the plant performance are for Cane Island 4 using standard GE data for a 1x1 7FA combined cycle plant. This performance is considered representative of F class combined cycle performance. Performance degradation of 2.7 percent for output and 1.5 percent for heat rate has been included in the estimated performance.

Table 9-4
Estimated 1x1 F Class Combined Cycle Performance (Natural Gas)

Performance Point	Unit Output (kW)	Unit Heat Rate (Btu/kWh, HHV)
Winter (19° F and 58% relative humidity) (Full Load)	329,800	7,435
Summer (102° F and 33% relative humidity) (Full Load)	299,600	7,445
Average (73° F and 80% relative humidity) (Full Load with Duct Firing)	307,200	7,420
Average (73° F and 80% relative humidity) (Full Load without Duct Firing)	246,990	6,969
Average (73° F and 80% relative humidity) (75% Load)	192,110	7,289
Average (73° F and 80% relative humidity) (50% Load)	140,990	7,923

9.6 Emissions

The estimated emissions for Cane Island 4 are presented on Table 9-5. The estimated emissions include operation of an SCR.

Table 9-5
Cane Island 4 Estimated Emissions[1]

NO_x, ppmvd at 15% O_2	2
NO_x, lb/MBtu	0.0072
SO_2, lb/MBtu	0.0005
Hg, lb/MBtu	0.0
CO_2, lb/MBtu	114.8
CO, ppmvd at 15% O_2	7.5
CO, lb/MBtu	0.0165

[1]Emissions are at full load at 73° F, reflect operation on natural gas, and include the effects of SCR and dry-low NO_x combustors.

9.7 Availability

Equivalent availability is a measure of the capacity of a generating unit to produce power considering operational limitations such as equipment failures, repairs, routine maintenance, and scheduled maintenance activities. Equipment outages and forced outages are not predictable and, because of this, a forced outage of 2 percent was assumed for each year. Scheduled outages will be determined by the hours of operation and number of starts. While various F class turbine manufacturers determine the basis for scheduled outage intervals somewhat differently, they all have fairly consistent maintenance programs that typically consist of combustion inspections, hot gas path inspections, and major overhauls. Based on the expected operating profile for the plant, the equivalent availability for Cane Island 4 was estimated to be 94 percent. On average, 14 maintenance days per year and a 2 percent forced outage rate have been assumed.

9.8 Schedule

Cane Island 4 is planned to be available for operation during the summer 2011 peaking season. To achieve this plan, construction is planned to start during July 2009. A 22 month construction schedule is planned to provide a commercial operation date of May 1, 2011. Detailed engineering activities will be required in advance of July 2009 to achieve the planned commercial operation date. These activities are planned to

commence during the second quarter of 2008. Similarly, procurement activities such as specification, equipment proposal solicitation, and contract negotiation for the HRSG and other long-lead time equipment items, will occur during 2008 to allow for delivery of this equipment to support the schedule. A summary level schedule is provided in Figure 9-4.

Cane Island Power Park Unit 4
Summary Level Schedule

25-Apr-08

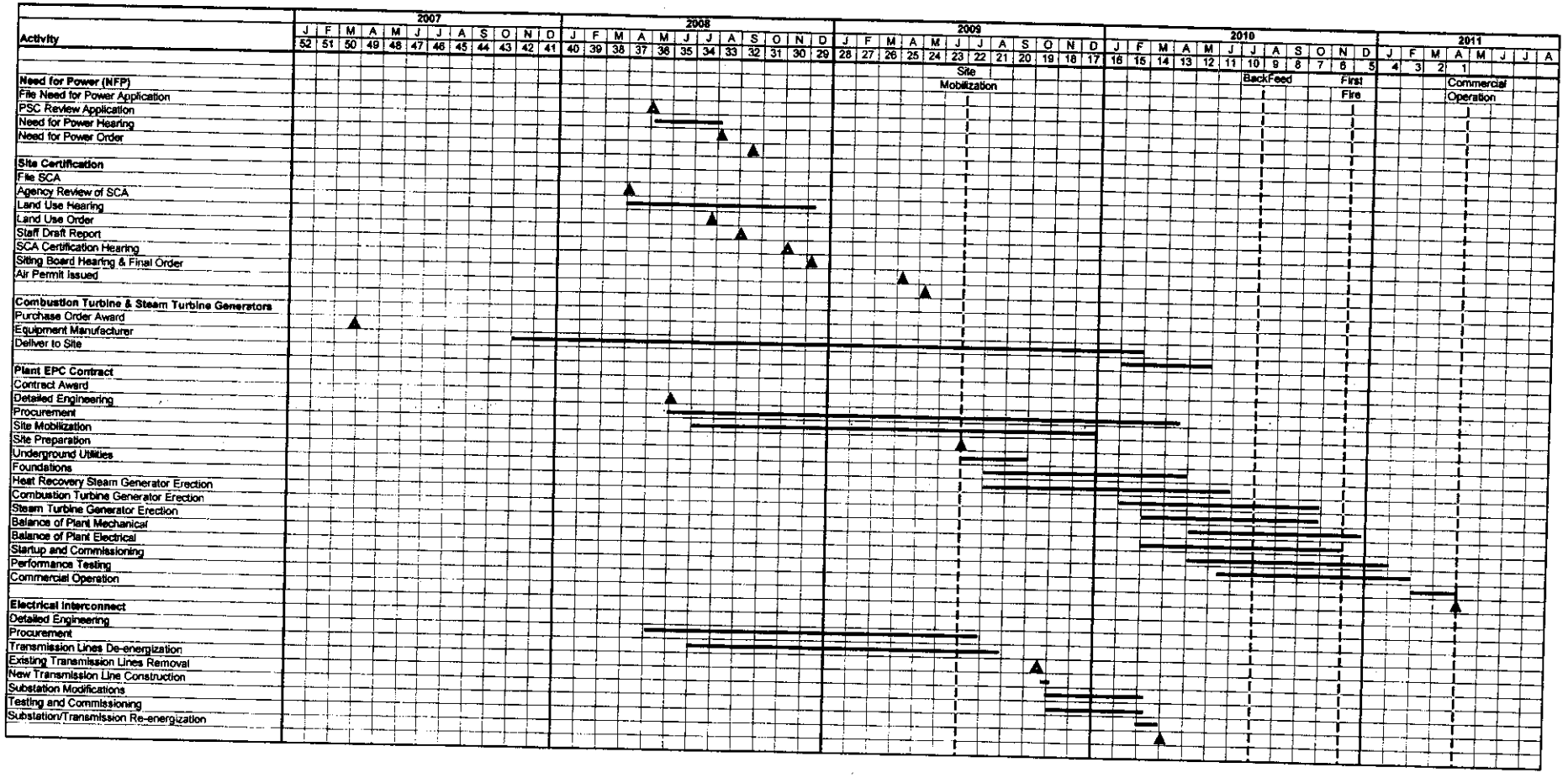


Figure 9-4
Cane Island 4 Schedule

10.0 Oil Backup Analysis

This section reviews issues relevant to dual fuel capability for Cane Island 4 within the current operating environment in Peninsular Florida. In reviewing the projected operation of Cane Island 4, FMPA has concluded that the incremental benefit of including oil backup capability in this unit are overshadowed by the incremental costs, maintenance, and limited reliability benefits associated with this capability. The natural gas transportation system for Florida has become significantly more diversified in recent years; both in delivery capability as well as receipt point access to supply. As a result, the delivery of natural gas in Florida has become much more reliable. Moreover, the large amount of natural gas generation with oil backup in the state makes the availability of oil when it might be needed more uncertain. Furthermore, Cane Island 4 is currently connected to two independent sources of supply; making the disruption of Cane Island 4's natural gas supply much more unlikely.

10.1 Historical Rationale Regarding Oil Backup

The Florida Public Service Commission (FPSC) must take into account the need for electric system reliability and integrity, including fuel supply reliability. Historically, utilities proposed dual fuel capability because natural gas was supplied to Florida through a single natural gas pipeline. The single pipeline was subject to disruptions affecting the supply for all the natural gas usage in the state. The possibility of natural disasters (such as hurricanes that could affect the predominant supply source in the Gulf of Mexico) has caused speculation of natural gas curtailments within the State of Florida. However, as the natural gas transportation network has expanded and supply sources more diverse, the probability that a hurricane or other natural disaster could or would disrupt natural gas supplies to the state has decreased.

In recent years, the FPSC has approved the need for natural gas fueled projects with oil backup as proposed. Those projects were generally served by a single natural gas pipeline. However, the FPSC approved Florida Power & Light Company's Manatee Unit 3 project without oil backup. Like the Cane Island site, Manatee Unit 3 has access to natural gas transportation service from both FGT and Gulfstream.

10.2 Federal Requirements

There are no federal requirements for oil backup for natural gas fueled generating plants. There are federal requirements, however, that mandate certain generating power plants are required to have dual fuel capability. Title II of the Power Plant and Industrial

Fuel Use Act of 1978 (FUA), as amended (42 U. S. C. 8301 et seq.), provides that no new baseload electric power plant fueled with natural gas or other petroleum products may be constructed or operated without the capability of use coal or another alternate fuel as a primary energy source. For the purpose of this requirement, a baseload facility is defined as one whose annual generation in kilowatt-hours exceeds its capacity multiplied by 3,500 hours (40 percent capacity factor). To meet the requirement of coal capability, the owner or operator of such facilities proposing to use natural gas or petroleum as its primary energy source shall certify (pursuant to FUA Section 201(d), and Section 501.60(a)(2) of DOE's regulations to the Secretary of Energy prior to construction or prior to operation as a baseload power plant) that such power plant has the capability to use coal or another alternate fuel. This certification is met for Cane Island 4 and other natural gas fueled combined cycles through the ability to be modified to burn syngas produced by coal. This requirement does not require Cane Island 4 to possess the capability to switch fuel in real time, but only requires that the plant be capable of generating electricity while burning the alternate fuel.

10.3 NERC Requirements

There are no NERC requirements that require Cane Island 4 to have oil backup.

10.4 Florida Gas Supply

Section 8.0 provides a detailed description of the natural gas transportation system in Florida. Initially, peninsular Florida was served by a single natural gas pipeline owned by FGT. As natural gas consumption in the state has grown, the natural gas transportation network has become much more diverse as described in Section 8.0. Currently, peninsular Florida is served by the FGT pipeline, the Gulfstream pipeline, and the Cypress pipeline. The pipelines provide geographic diversity, which mitigates potential disruption from hurricanes and other natural disasters. Proposed expansions by FGT and Gulfstream will provide even more diversity. In addition to the redundancy afforded by multiple pipelines, diversity has increased regarding the receipt of gas into the serving pipelines with the introduction of significant new storage and supply sources as described in Section 6.0. Geographic diversity of supply and storage makes it increasingly unlikely that a single hurricane or other natural disaster will interrupt the supply flow of natural gas to Florida. The reliability of natural gas supply to Florida is markedly improved over what it was just a few short years ago.

10.5 Disadvantages of Dual Firing

The potential increased reliability available using fuel oil backup must be carefully balanced with the disadvantages of installing and maintaining such backup. The cost disadvantages include both capital and operation costs. The capital costs required for oil backup are generally greater than appear at first blush due to the capital costs for fuel oil handling and storage facilities and for the associated costs for providing the demineralized water necessary to meet air quality requirements for combustion turbine operation using fuel oil. The estimated capital costs for adding oil backup to Cane Island 4 are presented in Table 10-1.

In addition to the increased capital cost, there are also costs associated with:

- Increased demineralized water consumption resulting from water injection when operating on fuel oil.
- Increased air permitting requirements.
- Increased operations and maintenance costs to maintain and test the added equipment including test firing on fuel oil.
- Increased permit requirements due to increased water consumption and wastewater disposal.
- Increased environmental compliance requirements during operation of the plant.
- Increased probability of forced outage due to increased equipment complexity.
- Deterioration of stored fuel resulting in chance of failure when switching to fuel oil or starting on fuel oil.

10.6 Fuel Oil Delivery Limitations

Another disadvantage that should be considered to the further reliance on fuel oil as backup in Florida relates to its availability during times of crisis. If a situation arose requiring significant consumption of fuel oil for power generation, the ability of the existing infrastructure to deliver the quantities required could be overwhelmed.

The most recent data available for the Florida system indicates that 39,600 MW of generation can be fueled with natural gas. Of this amount, nearly 29,000 MW of generation is capable of switching from gas to fuel oil. Using an average conversion efficiency (heat rate) of 9,000 Btu/KWh for capacity operating on fuel oil, the hourly consumption at full load equates to a consumption rate of 1,890,000 gallons per hour.

Table 10-1
Cost to Add Liquid Fuel Firing for Cane Island 4

Item	Estimated Cost, $
GE CTG Scope Addition	1,100,000
GE Scope Erection/BOP	370,000
Fuel Oil Storage Tanks, FP, and Berms	1,500,000
Fuel Oil Unloading	--
Fuel Oil Forwanding Skid	160,000
Piping and Electrical - Plant to Tanks	950,000
Demineralized Storage	1,250,000
Reverse Osmosis Unit	1,080,000
Water Treatment Building	230,000
False Start Drain Tank	50,000
Wastewater Additions	100,000
Demin Water Pumping	50,000
Service Water Pumping	50,000
EPC Contractor Markups	580,000
Startup and Commissioning Fuel Usage	2,500,000
Fill of Fuel Oil Tank for Commercial Operation	2,500,000
Interest and Bond Fees on Capital	560,000
Total	13,030,000

As shown in Table 10-2, based on a maximum pumping rate for the typical fuel delivery truck in the Florida market, approximately 315 trucks pumping at full capacity would be required to supply the needed fuel for each hour of the pipeline outage with several times that number being required to maintain the pumping capacity. While it would be unlikely that the entire dual fuel capacity would be needed at the same time, the number of trucks required would still be staggering. In addition, the fuel oil sources would likely come from the Gulf Coast and subject to much the same natural disaster exposure experienced by the natural gas supply. It is likely that natural gas supply flow to Florida would be restored before the fuel oil capacity.

Table 10-2
Fuel Oil Requirements

Item	Quantity	Unit
Dual Fuel Capability	29,000	MW
Heat Rate	9,000	Btu/KWh
Calorific Value	5.8	MBtu/bbl
Hourly Fuel Oil Burn	261,000	MBtu/hour
Hourly Fuel Oil Flow	1,890,000	Gallons/hour
Typical Size of Truck	4,500	Gallons
Maximum Pumping Rate	6,000	Gallons/hour
Required Number of Trucks	315	Trucks/hour

10.7 Existing FMPA Dual Fuel Capability

All of FMPA's existing natural gas fueled generation has oil backup. For the summer of 2008, this will amount to 1,032 MW. When Cane Island 4 comes online in the summer of 2011, it will comprise approximately 19.9 percent of FMPA's peak demand, which is only slightly more than FMPA's 18 percent reserve margin. With all of FMPA's existing natural gas fueled generation with oil backup and Cane Island 4 only representing FMPA's reserve margin, the installation of Cane Island 4 will maintain reliability for FMPA's system and Florida as a whole.

10.8 Cane Island Site

The Cane Island site is unique in several ways. First, it is served by both FGT and Gulfstream, thereby decreasing the probability that the supply of natural gas would be disrupted simultaneously on each pipeline. The Cane Island site contains three existing units, all of which have oil backup. If there were a severe limitation on the volume of natural gas available, the gas that was available could be used in Cane Island 4 and the other three Cane Island units would operate on fuel oil. The Cane Island facility would be 100 percent available in this scenario.

Gas supply to the Cane Island site historically has been extremely reliable. Since the first unit at Cane Island went into operation in 1995, oil has been burned at Cane Island a total of 77 hours. The 77 hours of operation on oil is equivalent to 0.07 percent increase in the forced outage rate. No reliability evaluation could ever justify the

expenditure of $13.0 million for a 0.07 percent improvement in the forced outage rate of a 300 MW combined cycle.

10.9 Conclusion

The increase in gas fired generation in Florida has resulted in diminishing returns with regard to the installation of oil as a backup fuel. Further use of oil as a backup fuel will do little to increase reliability and certainly is not cost effective relative to the small increase in demonstrated reliability. The natural gas supply system in Florida has become increasingly diverse and reliable. With two independent suppliers of natural gas (FGT and Gulfstream) to the Cane Island Site, Cane Island 4 will have a reliable fuel supply. Consistent with previous FPSC decisions regarding backup fuel for sites with two natural gas supplies, the addition of fuel oil for backup at Cane Island 4 is not justified.

11.0 Transmission System Impacts

Cane Island 4 will be interconnected to the existing Cane Island substation which is interconnected to the jointly owned FMPA and Kissimmee Utility Authority (KUA) transmission system. FMPA completed a study evaluating the connection of the Cane Island 4 associated with Generator Interconnection Service (GIS) to the FMPA/KUA Transmission System. In addition, FMPA completed an attendant request for Network Resource Interconnection Service (NRIS) with Progress Energy Florida (PEF).

The proposed interconnection and integration of Cane Island 4 have been evaluated and approved by FRCC, which found that the project will be reliable and adequate, and that it will not adversely impact the FRCC transmission system. PEF also has approved the request for NRIS. The following sections describe the interconnection, the system impact analysis, and the FRCC and PEF approvals.

11.1 Description of Interconnection

The existing Cane Island plant and its associated transmission lines are jointly owned by KUA and FMPA. Cane Island has existing direct transmission interconnections with Kissimmee Utility Authority (KUA), Orlando Utilities Commissions (OUC), Tampa Electric Company (TECO), and PEF. Two 230kV transmission lines routed to the north of Cane Island connect to the TECO Osceola and OUC Taft Substations respectively. A 230kV line routed to the east of Cane Island plant connects to Clay Street Substation jointly owned by FMPA and KUA. Another 230kV line routed to the west connects to Intersection City Substation owned by PEF.

The Cane Island 230kV substation station will be reconfigured and expanded by one bay to interconnect the Cane Island 4 combustion turbine generator (CTG) and steam turbine generator (STG) via a collector bus. Existing on-site transmission lines will be rerouted to accommodate the new unit. The CTG and STG will each connect to separate 18kV/230kV generator step-up transformers. The CTG and STG will each have generator breakers. Auxiliary power will be provided by auxiliary transformers connected to each generator's 18kV isolated phase bus duct.

11.2 System Impact Analysis

The purpose of the study conducted by FMPA was to identify thermal overloads and voltage limit violations, to identify any circuit breaker short circuit capability limits, and to identify any instability or inadequately damped response to system disturbances resulting from Cane Island 4.

The study included Load Flow Analysis of the transmission service request to provide Cane Island 4 with NRIS, Short Circuit Analysis, and Dynamic Stability Analysis. FRCC provided the evaluation of the Steady State Analysis with the load flow screening results.

The purpose of the short circuit analysis was to determine the impact of increased fault currents as a result of Cane Island 4 addition. The analysis result indicates that fault current levels were close to the 40 kA interruptible rating at the Cane Island 230kV substation. FMPA plans to remedy the situation by replacing the 230kV circuit breakers at Cane Island substation with 2 cycle, 63 kA breakers. The cost associated with replacing the breakers is included in the Owner's Costs portion of the Cane Island 4 capital cost estimate in Table 9-3.

The dynamic stability analysis simulations resulted in delayed clearing faults which indicate no instability or inadequately damped response to system disturbances or any adverse impact to the system.

11.3 FRCC and PEF Approval

FRCC's Transmission Working Group (TWG) and Stability Working Group (SWG) evaluated the proposed interconnection and integration of the Cane Island 4. The TWG reviewed the Steady State, Stability, and Short Circuit Analysis of the proposed interconnection and integration. Based on the review and analysis conducted by TWG and SWG, the FRCC Planning Committee approved the proposed interconnection and integration plan finding that, with currently scheduled system upgrades, it will be reliable and adequate and that it will not adversely impact the reliability of the FRCC transmission system. PEF likewise approved FMPA's request for NRIS.

12.0 Reliability Criteria

Prudent utility practices require a utility to plan for sufficient capacity resources to meet its peak demand and to maintain an additional margin of capacity should unforeseen events result in higher system demand or lower than anticipated availability of capacity. This section presents the development and analysis of the reliability criteria used by FMPA.

A number of methods are used in the electric utility industry to calculate a utility's system reliability. One method is the reserve margin and another is the Loss of Load Probability (LOLP); these approaches apply deterministic and probabilistic methods, respectively, to calculate the reliability of a system. FMPA uses a reserve margin for planning purposes that accounts for partial requirements (PR) and other purchases that include reserves. The two methods are discussed in the following subsections.

12.1 Reserve Sharing Requirements

Section 25-6.035 of the Florida Administration Code (FAC) requires that Florida utilities maintain a minimum 15 percent planned reserve margin for purposes of equitable sharing of energy reserves. Section 25-6.035 indicates that this 15 percent minimum requirement is not for setting a prudent level of reserves for long-term planning or reliability purposes.

12.2 Reserve Margin Requirements

12.2.1 Traditional

FMPA uses a minimum 18 percent reserve margin in the summer and a minimum 15 percent reserve margin in the winter. The planning reserve margin covers uncertainties in extreme weather, forced outages for generators, and uncertainty in load projections. FMPA plans to maintain its seasonal reserve margins for firm load obligations. The higher reserve margin in the summer helps mitigate risk from the summer peak periods, which are generally much longer in duration than the winter peak periods.

The most commonly used deterministic method is the reserve margin method, which is calculated as follows:

$$\frac{\text{System Net Capacity - System Firm Peak Demand (After Interruptible Load)}}{\text{System Firm Peak Demand (After Interruptible Load)}}$$

FMPA has several PR purchases in which the supplying utility is responsible for providing reserves. Therefore, FMPA subtracts the PR services from the net capacity and peak demand. The formula used by FMPA to calculate its reserve margin is based on the following, which considers that the PR purchases include their own reserves:

$$\frac{\text{(System Net Capacity - PR) - (System Net Peak Demand - PR)}}{\text{(System Net Peak Demand - PR)}}$$

12.2.1.1 Demand Response Considerations. Special consideration needs to be given to the portion of planned reserve requirements that can be covered by demand response (DR). Because DR grows as a portion of planned reserves, the frequency that DR is exercised increases. Depending upon the nature of the DR, increased frequency of its use can result in customer dissatisfaction, even to the extent that they leave the DR program, which can further exasperate reserve issues. Progress Energy Florida encountered this situation a few years ago, when many customers left their direct load control program.

FMPA has not specifically evaluated this limit for its system. The DR levels potentially anticipated in this application do not appear to be great enough to cause this problem. If, in the future, greater DR levels are implemented, limits on prudent DR levels may be encountered. Though FMPA has not evaluated this limit specifically, general observations indicate that the prudent upper DR level may be approximately half of the planning reserve margin.

12.2.1.2 Renewable Considerations. The inclusion of significant amounts of renewable energy that is neither dispatchable nor controllable raises questions with respect to its contribution to system reliability. Solar and wind are primary examples of this type of capacity. Currently, FMPA is not anticipating adding wind capacity to its system, but is actively pursuing the addition of solar photovoltaic capacity. As discussed in Section 13.0, FMPA's capacity addition requirements are driven by summer peak loads. An analysis of solar photovoltaic's capacity factor over the expected times of FMPA's summer peak indicates that solar photovoltaic generation would have an average capacity factor of approximately 33 percent.

For this Application, 33 percent of the nameplate capacity for solar photovoltaic was counted as firm capacity in order to calculate reserve margins. At a 10 MW solar photovoltaic nameplate level, the contribution to firm reserves and its attendant effect on reliability would be minimal. With significantly higher levels of photovoltaic generation, this approach will require additional evaluation, especially with respect to system reliability. The results of this additional evaluation may result in a requirement for some

level of backup capacity or DR for photovoltaic capacity. In addition, further evaluation may indicate a need to limit the amount of photovoltaic capacity proportionate to the planning reserve margin, as discussed in the previous subsection for DR.

12.3 LOLP

LOLP is the second commonly used method of calculating the reliability of a utility system. This method is advantageous in that it can result in a measure of how much capacity is needed to meet a target level of reliability (typically, an LOLP criterion of no more than 1 day in 10 years is used). FRCC utilizes a reserve margin criterion (Resource Adequacy Standard) for capacity planning purposes that results in resource levels that meet an LOLP criterion of no more than 1 day in 10 years. The Resource Adequacy Standard calls for a reserve margin of 15 percent versus firm load.

The calculation of LOLP for an individual utility is difficult because of the need to properly evaluate the level of assistance from neighboring utilities. For FMPA, this problem is compounded since the ARP comprises 15 individual utilities. An LOLP evaluation for FMPA has not been conducted. Several years have passed since an LOLP evaluation was conducted for FRCC. The last evaluation confirmed that FRCC's LOLP met the 1 day in 10 years criterion.

12.4 Reliability Criteria Summary

For evaluation purposes for this Application, an 18 percent summer reserve margin and 15 percent winter reserve margin were used for capacity addition requirements. For evaluation purposes for this Application, all of the DR was used to reduce firm load requirements in order to calculate the reserve requirements, and 33 percent of the nameplate capacity of solar photovoltaic capacity was counted as firm capacity.

13.0 Capacity Requirements

This section presents FMPA's projected annual capacity requirements necessary to maintain the 18 percent summer reserve margin criteria, taking into consideration existing and future planned capacity resources as described in Section 3.0 and the base case load forecast presented in Section 5.0. The projected need for capacity is used as the basis for the analyses presented in Section 20.0.

Available net system capacity resources consider existing generation resources, contractual power purchases, and any reserves associated with partial requirements (PR) purchases, scheduled capacity additions and unit re-ratings, and scheduled unit retirements. Section 3.0 provides a description of FMPA's existing capacity resources and planned retirements. In addition to these retirements, the City of Vero Beach's existing resources will not be available to FMPA after January 1, 2010, as a result of the establishment of the CROD.[1] Currently, FMPA is projected to continue serving approximately 21 MW of the City of Vero Beach's summer loads on an annual basis, as part of the CROD, beginning January 1, 2010.

FMPA's current firm power supply purchases include those from PEF, FPL, Calpine, Southern Company-Florida, LLC, and Southern Power Company. The power purchases are summarized in Section 3.3. Currently, FMPA has no firm contractual wholesale power sales agreements.

As shown in Section 5.0, FMPA's forecast annual peak demands are projected to occur in the summer of each year. As a result, the capacity additions necessary to maintain the forecast capacity requirements are driven by projected summer peak demands. The load forecast developed by RW Beck (presented in Section 5.0) extends through the year 2026. For the purposes of the analyses presented throughout this Application, the load forecast was extended to the year 2027 by applying the annual growth rate from 2025 to 2026 to the year 2026 forecast.

Table 13-1 indicates that FMPA's capacity is initially projected to fall below its required 18 percent reserve margin in the summer of 2010. At that time, FMPA's reserve margin is projected to fall to 17.7 percent, or 3 MW below the capacity required to maintain an 18 percent reserve margin. By the summer of 2011, FMPA's reserve margin is projected to fall to -1.3 percent, or 286 MW below the capacity required to maintain an 18 percent reserve margin. Projected summer capacity deficits continue to increase beyond 2011, growing to an estimated deficit of 1,098 MW by 2027.

[1] Ultimately, the CROD will be based on Vero Beach's peak demand from December 1, 2008 through November 30, 2009.

Table 13-1
Projected Reliability Levels – Summer – Base Case Load Forecast

Year	Net Generating Capacity (MW)	Non-Partial Requirements Purchases (MW)	Partial Requirements Purchases (MW)	Net Firm Planned Capacity Reductions[1] (MW)	Net Firm Capacity Additions[2] (MW)	Net System Capacity (MW)	System Peak Demand[3] (MW)	Reserve Margin[4] (%)	Excess/(Deficit) to Maintain 18% Reserve Margin (MW)
2008	1,318	337	75	(114)	296	1,912	1,545	25.0%	103
2009	1,318	337	120	(114)	296	1,957	1,593	24.7%	98
2010	1,318	237	165	(300)	296	1,717	1,483	17.7%	(3)
2011	1,318	237	45	(389)	296	1,508	1,527	-1.3%	(286)
2012	1,318	237	45	(426)	296	1,470	1,560	-5.9%	(363)
2013	1,318	237	0	(426)	296	1,425	1,594	-10.6%	(456)
2014	1,318	237	0	(426)	296	1,425	1,630	-12.6%	(498)
2015	1,318	237	0	(426)	296	1,425	1,668	-14.5%	(542)
2016	1,318	237	0	(426)	296	1,425	1,705	-16.4%	(587)
2017	1,318	237	0	(426)	296	1,425	1,744	-18.2%	(632)
2018	1,318	237	0	(426)	296	1,425	1,782	-20.0%	(677)
2019	1,318	237	0	(426)	296	1,425	1,820	-21.7%	(722)
2020	1,318	237	0	(426)	296	1,425	1,859	-23.3%	(768)
2021	1,318	237	0	(426)	296	1,425	1,898	-24.9%	(814)
2022	1,318	237	0	(426)	296	1,425	1,938	-26.4%	(861)
2023	1,318	237	0	(426)	296	1,425	1,978	-27.9%	(908)
2024	1,318	237	0	(426)	296	1,425	2,018	-29.3%	(955)
2025	1,318	237	0	(426)	296	1,425	2,057	-30.7%	(1,002)
2026	1,318	237	0	(426)	296	1,425	2,098	-32.0%	(1,050)
2027	1,318	237	0	(426)	296	1,425	2,139	-33.4%	(1,098)

[1]Reflects annual capacity retirements described in Section 3.0, changes to the ratings of existing nuclear generating resources, and the loss of City of Vero Beach's generating units associated with CROD, all described in Section 3.0.
[2]Firm capacity additions reflect commercial operation of TCEC Unit 1 combined cycle (May 2008).
[3]City of Vero Beach's forecast capacity requirements are no longer included beginning January 1, 2010, when the CROD becomes effective, except for approximately 21 MW of the City of Vero Beach's load resulting from the CROD.
[4]Reserve margin calculated as (Net System Capacity - Partial Requirements Purchases) - (System Peak Demand - Partial Requirements Purchases) / (System Peak Demand - Partial Requirements Purchases).

14.0 Supply-Side Alternatives

This section presents the conventional and emerging supply-side technologies that were considered by FMPA. Estimated performance characteristics, emissions profiles, capital and operating costs, availability, and construction schedules are presented.

14.1 Conventional and Emerging Technologies

The conventional and emerging generating options that were evaluated as potential sources of future capacity for FMPA are discussed in this section. In addition to a general description, a summary of projected performance, emissions, capital cost, O&M costs, startup costs, construction schedules, scheduled maintenance requirements, and forced outage rates have been developed for each option.

Cost and performance estimates have been developed for several conventional self-build generation technologies that are proven, commercially available, and widely used in the power industry. Additionally, cost and performance estimates were developed for the LMS100 simple cycle combustion turbine, which may be considered an emerging technology. An emerging technology is a technology that cannot be considered conventional for various reasons, as discussed further in this analysis.

Although the combustion turbines and the combined cycle alternatives discussed herein assume a specific manufacturer (GE) and specific models (e.g., aeroderivative and frame combustion turbines), doing so is not intended to limit the alternatives considered solely to GE models. Rather, such assumptions were made to provide indicative cost, output, and performance data. Several manufacturers offer similar generating technologies with similar attributes, and the data presented in this analysis should be considered indicative of comparable technologies across a wide array of manufacturers.

Based on currently developing policy in the state and concern over CO_2 emissions, solid fuel generating facilities have not been included as generating unit alternatives. In addition, nuclear units are not included beyond the potential identified joint ownership opportunities with FPL and PEF, as described in Section 19.0, because of the large size of the nuclear units and the need to have another entity develop and manage the projects.

The capital cost estimates developed include both direct and indirect costs. An allowance for possible general owner's cost items, as summarized in Table 14-1, has been included in the cost estimates.

Table 14-1
Possible Owner's Costs

Project Development

- Site selection study
- Land purchase/rezoning for greenfield sites
- Transmission/gas pipeline right-of-way
- Road modifications/upgrades
- Demolition
- Environmental permitting/offsets
- Public relations/community development
- Legal assistance
- Provision of project management

Spare Parts and Plant Equipment

- Combustion turbine materials, gas compressors, supplies, and parts
- Steam turbine materials, supplies, and parts
- Boiler materials, supplies, and parts
- BOP equipment/tools
- Rolling stock
- Plant furnishing and supplies

Plant Startup/Construction Support

- Owner's site mobilization
- O&M staff training
- Initial test fluids and lubricants
- Initial inventory of chemicals and reagents
- Consumables
- Cost of natural gas not recovered in power sales
- Auxiliary power purchases
- Acceptance testing
- Construction all-risk insurance

Owner's Contingency

- Owner's uncertainty and costs pending final negotiation
- Unidentified project scope increases
- Unidentified project requirements
- Costs pending final agreements (i.e., interconnection contract costs)

Owner's Project Management

- Preparation of bid documents and the selection of contractors and suppliers
- Performance of engineering due diligence
- Provision of personnel for site construction management

Taxes/Advisory Fees/Legal

- Taxes
- Market and environmental consultants
- Owner's legal expenses
- Interconnect agreements
- Contracts (procurement and construction)
- Property

Utility Interconnections

- Natural gas service
- Gas system upgrades
- Electrical transmission
- Water supply
- Wastewater/sewer

Financing (included in fixed charge rate, but not in direct capital cost)

- Financial advisor, lender's legal, market analyst, and engineer
- Loan administration and commitment fees
- Debt service reserve fund

14.1.1 Generating Alternatives Assumptions

14.1.1.1 General Capital Cost Assumptions. Unless otherwise discussed for each site, the following general assumptions were applied in developing the cost and performance estimates:

- The site has sufficient area available to accommodate construction activities including, but not limited to, office trailers, laydown, and staging.
- Pilings are assumed under major equipment, and spread footings are assumed for all other equipment foundations.
- All buildings will be preengineered unless otherwise specified.
- Construction power is available at the boundary of the site(s).
- The LMS100 is assumed to have standard SCR. The LM6000, 7EA, and 7FA simple cycle combustion turbines will have hot SCR. Except for the LMS100, the simple cycle units will not include a CO catalyst, but will have a spool piece for future installation.
- GE 7FA combined cycle plants will include SCR and space for a potential CO catalyst to reduce emissions.
- Standard sound enclosures will be included for the combustion turbines.
- Natural gas pressure is assumed to be adequate for the 7EA simple cycle and the 7FA simple and combined cycle alternatives. Gas compressors will be included for the LM6000 and LMS100 aeroderivative combustion turbines. A regulating and metering station is assumed to be part of the owner's cost for each alternative.
- Demineralized water will be supplied by a demineralized water treatment system for the combined cycle option.
- The LMS100 and the combined cycle alternatives will utilize cooling towers. Groundwater or treated sewage effluent will be used as cooling water.
- The LMS100 has an intercooled compressor and will not utilize inlet cooling. The LM6000 will include the SPRINT option and will also include inlet chillers. The frame machines (simple cycle turbines and combined cycles) will utilize evaporative cooling.
- Field erected service/fire water storage tanks are included.

14.1.1.2 Fuel Assumptions.

- Fuel gas is 100 percent methane with 0.2 grain of sulfur per 100 standard cubic feet (scf), with a heat content of 21,515 Btu/lb, lower heating value (LHV).

14.1.1.3 Direct Cost Assumptions.

- Total direct capital costs are expressed in 2008 dollars unless otherwise noted.
- Direct costs include the costs associated with the purchase of equipment, erection, and contractors' services.
- Construction costs are based on an EPC contracting philosophy.
- Spare parts for startup are included. Initial inventory of spare parts for use during operation is included in the owner's costs.
- Permitting and licensing are included in the owner's costs.

14.1.1.4 Indirect Cost Assumptions. The following items are assumed in the capital cost estimate:

- General indirect costs, including all necessary services required for checkout, testing, and commissioning.
- Insurance, including builder's risk, general liability, and liability insurance for equipment and tools.
- Engineering and related services.
- Field construction management services including field management staff with supporting staff personnel, field contract administration, field inspection and quality assurance, and project control.
- Technical direction and management of startup and testing, cleanup expense for the portion not included in the direct cost construction contracts, safety and medical services, guards and other security services, insurance premiums, and performance bonds.
- Contractor's contingency and profit.
- Transportation costs for delivery to the jobsite.
- Startup and commissioning spare parts.
- Interest during construction and financing fees will be accounted for separately in the economic evaluation and, therefore, are not included in the capital cost or owner's cost estimates.

14.1.1.5 Meteorological Conditions. An average annual temperature and relative humidity of 70° F and 72 percent, respectively, were used for developing performance estimates for use in production cost modeling. Additionally, a winter temperature of 24° F (relative humidity of 91.9 percent) and a summer temperature of 98° F (relative humidity of 54.9 percent) were used to develop seasonal performance estimates.

14.1.1.6 Performance Degradation. Power plant output and heat rate performance will degrade with hours of operation because of factors such as blade wear, erosion,

corrosion, and increased tube leakage. Periodic maintenance and overhauls can recover much, but not all, of the degraded performance when compared to the unit's new and clean performance. The degradation that cannot be recovered is referred to herein as nonrecoverable degradation, and estimates have been developed to capture its impacts. Nonrecoverable degradation will vary from unit to unit, so specific nonrecoverable output and heat rate factors have been developed and are presented in Table 14-2. The degradation percentages are applied one time to the new and clean performance data, and reflect lifetime aggregate nonrecoverable degradation.

Table 14-2
Nonrecoverable Degradation Factors

Unit Description	Degradation Factor	
	Output (%)	Heat Rate (%)
GE LM6000 Simple Cycle	3.2	1.75
GE LMS100 Simple Cycle	3.2	1.75
GE 7EA Simple Cycle	3.2	1.75
GE 7FA Simple Cycle	3.2	1.75
GE 1x1 7FA Combined Cycle	2.7	1.50

14.1.2 Existing Sites

The generating unit alternatives considered throughout this Application, with the exception of the combined cycles, were developed on a greenfield basis. Future combined cycle units would likely be installed at either FMPA's TCEC or CIPP sites. These sites are discussed below.

A final Determination of Need Order was issued for Unit 1 at the TCEC site by the FPSC on July 27, 2005. This site will have adequate acreage to accommodate up to four (including Unit 1) 1x1 GE 7FA combined cycle units. Site certification for TCEC was issued in May 2006 for Unit 1 and ultimate certification for 1,200 MW. TCEC is located within Phase III - north of the Midway Industrial Park in St. Lucie County, Florida. The TCEC site is in southwest Ft. Pierce, 8 miles northwest of Port St. Lucie, and occupies 68.1 acres.

The CIPP site is located approximately 5 miles west of the city limits of Kissimmee, Florida. The site currently has three natural gas and No. 2 oil fueled generating units, including Cane Island 1 (a simple cycle LM6000 combustion turbine), Cane Island 2 (a 1x1 7EA combined cycle), and Cane Island 3 (a 1x1 7FA combined cycle), with a total installed summer capacity of 388 MW. The units are jointly owned

by KUA and FMPA. Cane Island 4, which will be wholly owned by FMPA, will add an additional 300 MW of summer capacity.

The Cane Island site was designed for approximately 1,000 MW of combustion turbine and combined cycle capacity and is served by the FGT and Gulfstream natural gas pipeline systems. The site is interconnected at 230 kV with PEF, OUC, TEC, and KUA. The site uses treated sewage effluent from the Toho Water Authority for cooling water; the site also has rights for additional cooling water from Toho Water Authority.

14.1.3 Simple Cycle Combustion Turbine Alternatives

CTGs are sophisticated power generating machines that operate according to the Brayton thermodynamic power cycle. A simple cycle combustion turbine generates power by compressing ambient air and then heating the pressurized air to approximately 2,000° F or more, by burning oil or natural gas, with the hot gases then expanding through a turbine. The turbine drives both the compressor and an electric generator. A typical combustion turbine would convert 30 to 35 percent of the fuel to electric power. A substantial portion of the fuel energy is wasted in the form of hot gases (typically 900° F to 1,100° F) exiting the turbine exhaust. When the combustion turbine is used to generate power and no energy is captured and utilized from the hot exhaust gases, the power cycle is referred to as a "simple cycle" power plant.

Combustion turbines are mass flow devices, and their performance changes with changes in the ambient conditions at which the unit operates. Generally speaking, as temperatures increase, combustion turbine output and efficiency decrease because of the lower density of the air. To lessen the impact of this negative characteristic, most of the newer combustion turbine-based power plants often include inlet air cooling systems to boost plant performance at higher ambient temperatures.

Combustion turbine pollutant emission rates are typically higher on a part per million (ppm) basis at part load operation than at full load. This limitation has an effect on how much plant output can be decreased without exceeding pollutant emissions limits. In general, combustion turbines can operate at a minimum load of about 50 percent of the unit's full load capacity while maintaining emission levels within required limits.

Advantages of simple cycle combustion turbine projects include low capital costs, short design and construction schedules, and the availability of units across a wide range of capacities. Combustion turbine technology also provides rapid startup and modularity for ease of maintenance.

The primary drawback of combustion turbines is that, due to the cost of natural gas and fuel oil, the variable cost per MWh of operation is high compared to other conventional technologies. As a result, simple cycle combustion turbines are often the technology of choice for meeting peak loads in the power industry, but are not usually economical for baseload or intermediate service.

Three different commercially proven combustion turbine sizes were evaluated, as well as the LMS100. The GE LM6000 has a nominal output in the range of 50 MW at International Organization for Standardization (ISO) conditions with the SPRINT™ design feature included. The GE 7EA has a nominal output of about 85 MW, while the GE 7FA has a nominal output of about 170 MW at ISO conditions.

14.1.3.1 GE SPRINT LM6000 Combustion Turbine. The GE SPRINT LM6000 was selected as a potential simple cycle alternative because of its modular design, efficiency, and size. It is a two-shaft gas turbine engine derived from the core of the CF6-80C2, GE's high thrust, high efficiency aircraft engine.

The LM6000 consists of a five-stage low-pressure compressor (LPC); a 14-stage, variable geometry, high-pressure compressor (HPC); an annular combustor; a two-stage, air-cooled, high-pressure turbine (HPT); a five-stage, low-pressure turbine (LPT); and an accessory drive gearbox. The LM6000 has two concentric rotor shafts, with the LPC and LPT assembled on one shaft, forming the LP rotor. The HPC and HPT are assembled on the other shaft, forming the HP rotor.

The LM6000 uses the LPT to power the output shaft. The LM6000 design permits direct coupling to 3,600 rpm generators for 60 Hz power generation. The gas turbine drives its generator through a flexible, dry type coupling connected to the front, or "cold" end, of the LPC shaft. The LM6000 gas turbine generator set has the following attributes:

- Full power in approximately 10 minutes.
- Cycling or peaking operation.
- Synchronous condenser capability.
- Compact, modular design.
- More than 5 million operating hours.
- More than 450 turbines sold.
- 97.8 percent documented availability.
- LM6000 SPRINT™ spray intercooling for power boost.
- Dual fuel capability.

The capital cost estimate was derived utilizing GE's Next-Gen package for the LM6000. This package includes more factory assembly, resulting in less construction time. Table 14-3 presents the operating characteristics of the LM6000 SPRINT combustion turbine at a winter temperature of 24° F (relative humidity of 91.9 percent) and a summer temperature of 98° F (relative humidity of 54.9 percent), and annual average temperature conditions (70° F with a relative humidity of 72 percent). High temperature SCR would be used to control NO_x to 2 ppmvd while operating on natural gas. Table 14-4 presents estimated emissions for the LM6000.

Table 14-3
GE LM6000 PC SPRINT Combustion Turbine Characteristics

Ambient Condition	Net Capacity (MW)[1]	Net Plant Heat Rate (Btu/kWh, HHV)[1, 2]
Winter (24° F) (Full Load)	47.4	9,637
Summer (98° F) (Full Load)	46.2	10,171
Average (70° F and 72% relative humidity) (Full Load)	47.3	9,933
Average (70° F and 72% relative humidity) (75% Load)	26.5	11,304
Average (70° F and 72% relative humidity) (50% Load)	17.5	13,444

[1]Net capacity and net plant heat rate include degradation factors, inlet chilling is considered on full load cases above 60° F, and performance is preliminary.
[2]Heat rate assumes operation on natural gas.

Table 14-4
GE LM6000 PC SPRINT Estimated Emissions[1]

NO_x, ppmvd at 15% O_2	2
NO_x, lb/MBtu	0.0072
SO_2, lb/MBtu	0.0005
Hg, lb/MBtu	0.0
CO_2, lb/MBtu	114.8
CO, ppmvd at 15% O_2	29
CO, lb/MBtu	0.0648

[1]Emissions are at full load at 70° F, reflect operation on natural gas, and include the effects of SCR.

14.1.3.2 GE 7EA Combustion Turbine. The GE 7EA combustion turbine is a highly reliable, mid-sized combustion turbine developed specifically for 60 Hz applications. With design emphasis placed on energy efficiency, availability, performance, and maintainability, the GE 7EA is a proven technology with approximately 800 units installed worldwide, and more than a million hours of operation. The simple, mid-sized design of the GE 7EA lends to flexibility in plant layout and easy, low-cost addition of increments of power when phased capacity expansion is necessary. The unit has a 3,600 rpm shaft speed and is directly coupled to the generator.

The GE 7EA is fuel-flexible and can operate on natural gas, LNG, distillate fuel oil, and treated residual fuel oil. The 7EA is an ideal generating unit for sites that require efficient peaking generation or reliable capacity from multiple units. The 7EA is rated at 85.4 MW, which is greater than the LM6000, but less than the 7FA. For this analysis, it has been assumed that the GE 7EA will be dual-fueled, capable of firing either natural gas or ULSD.

Table 14-5 presents the operating characteristics of the GE 7EA combustion turbine at a winter temperature of 24° F (relative humidity of 91.9 percent), a summer temperature of 98° F (relative humidity of 54.9 percent), and an annual average temperature of 70° F (relative humidity of 72 percent). The 7EA will utilize dry-low NO_x combustors and SCR to control NO_x to 2 ppmvd on natural gas. Table 14-6 presents estimated emissions for the 7EA.

Table 14-5
GE 7EA Combustion Turbine Characteristics

Ambient Condition	Net Capacity (MW)[1]	Net Plant Heat Rate (Btu/kWh, HHV)[1]
Winter (24° F) (Full Load)	89.7	11,793
Summer (98° F) (Full Load)	72.4	12,399
Average (70° F and 72% RH) (Full Load)	78.4	12,134
Average (70° F and 72% RH) (75% Load)	58.7	13,214
Average (70° and 72% RH) (50% Load)	39.0	16,100

RH = Relative humidity.

[1]Net capacity and net plant heat rate include degradation factors, evaporative cooling is considered at full load cases above 60° F, and performance is preliminary.

Table 14-6 GE 7EA Estimated Emissions[1]	
NO_x, ppmvd at 15% O_2	2
NO_x, lb/MBtu	0.0073
SO_2, lb/MBtu	0.0005
Hg, lb/MBtu	0.0
CO_2, lb/MBtu	114.8
CO, ppmvd at 15% O_2	7.5
CO, lb/MBtu	0.0165
[1]Emissions are at full load at 70° F and include the effects of SCR.	

14.1.3.3 GE 7FA Combustion Turbine. The GE 7FA combustion turbine, originally introduced in 1986, is the result of a multi-year development program using technology advanced by GE Aircraft Engines and GE's Corporate Research and Development Center. The development program facilitated the application of technologies such as advanced bucket cooling techniques, compressor aerodynamic design, and new alloys for F class gas turbines, enabling these machines to attain higher firing temperatures (2,400° F) than previous generating units.

The GE 7FA combustion turbines have an 18-stage compressor and a 3-stage turbine and feature cold-end drive and axial exhaust, which is beneficial for combined cycle arrangements. With reduced cycle time for installation and startup, the GE 7FA can be installed relatively quickly. The packaging concept of the GE 7FA features consolidated skid-mounted components, controls, and accessories, which reduce piping, wiring, and other onsite interconnection work.

The GE 7FA combustion turbine has also exhibited outstanding environmental characteristics. Because of the higher specific output of these machines, smaller amounts of NO_x and CO are emitted per unit of power produced for the same exhaust concentrations as other generating technologies. GE 7FA turbines have accumulated more than 900,000 operating hours using dry low NO_x burners, which will be part of the NO_x control strategy when operating on natural gas. Evaporative cooling will be used for inlet cooling.

Table 14-7 presents the operating characteristics of the GE 7FA combustion turbine at a winter temperature of 24° F (relative humidity of 91.9 percent), a summer temperature of 98° F (relative humidity of 54.9 percent), and an annual average temperature of 70° F (relative humidity of 72 percent). The 7FA will utilize dry low NO_x combustors and SCR to control NO_x to 2 ppmvd on natural gas. Table 14-8 presents estimated emissions for the 7FA.

Table 14-7
GE 7FA Combustion Turbine Characteristics

Ambient Condition	Net Capacity (MW)[1]	Net Plant Heat Rate (Btu/kWh, HHV)[1]
Winter (24° F) (Full Load)	177.0	10,585
Summer (98° F) (Full Load)	148.5	11,065
Average (70° F and 72% relative humidity) (Full Load)	160.0	10,826
Average (70° F and 72% relative humidity) (75% Load)	119.8	11,816
Average (70° and 72% relative humidity) (50% Load)	79.6	14,223

[1]Net capacity and net plant heat rate include degradation factors, evaporative cooling is considered at full load cases above 60° F, and performance is preliminary.

Table 14-8
GE 7FA Estimated Emissions[1]

NO_x, ppmvd at 15% O_2	2
NO_x, lb/MBtu	0.0073
SO_2, lb/MBtu	0.0005
Hg, lb/MBtu	0.0
CO_2, lb/MBtu	114.8
CO, ppmvd at 15% O_2	7.5
CO, lb/MBtu	0.0165

[1]Emissions are at full load at 70° F and include the effects of SCR and dry low NO_x combustors.

14.1.3.4 GE LMS100 Combustion Turbine. The GE LMS100 is a new combustion turbine; the first LMS100 began commercial operation in July 2006. At the time this Application was prepared, only about half a dozen LMS100 units had been ordered from GE. After the reliability of the LMS100 has been successfully demonstrated, it will likely replace the use of two-unit blocks of LM6000s in the future.

The LMS100 is currently the most efficient simple cycle gas turbine in the world. In simple cycle mode, the LMS100 has an efficiency of 46 percent, which is 10 percent greater than the LM6000. It has a high part-load efficiency, cycling capability (without increased maintenance cost), better performance at high ambient temperatures, modular design (minimizing maintenance costs), the ability to achieve full power from a cold start in 10 minutes, and is expected to have high availability, though this availability must be commercially demonstrated before the LMS100 can be considered a conventional alternative.

The LMS100 is an aeroderivative turbine and has many of the same characteristics of the LM6000. The former uses off-engine intercooling within the turbine's compressor section to increase its efficiency. The process of cooling the air optimizes the performance of the turbine and increases output efficiency. At 50 percent turndown, the part-load efficiency of the LMS100 is 40 percent, which is a greater efficiency than most simple cycle combustion turbines at full load.

There are two main differences between the LM6000 and the LMS100. The LM6000 uses the SPRINT intercooling system to cool the compressor with a micro-mist of water, while the LMS100 cools the compressor air with an external heat exchanger after the first stage of compression. Unlike the LM6000, which has a HP turbine and a power turbine, the LMS100 has an additional IP turbine to increase output efficiency.

As a packaged unit, the LMS100 consists of a 6FA turbine compressor, which outputs compressed air to the intercooling system. The intercooling system cools the air, which is then compressed in a second compressor to a high pressure, heated with combusted fuel, and then used to drive the two-stage IP/HP turbine described above. The exhaust stream is then used to drive a five-stage power turbine. Exhaust gases are at a temperature of less than 800° F, which allows the use of a standard SCR system for NO_x control.

Table 14-9 presents the operating characteristics of the LMS100 combustion turbine at a winter temperature of 24° F (relative humidity of 91.9 percent), a summer temperature of 98° F (relative humidity of 54.9 percent), and an annual average temperature of 70° F (relative humidity of 72 percent). Standard SCR will be used to control NO_x to 2 ppmvd while operating on natural gas. Table 14-10 presents estimated emissions for the LMS100.

Table 14-9
GE LMS100 Combustion Turbine Characteristics

Ambient Condition	Net Capacity (MW)[1]	Net Plant Heat Rate (Btu/kWh, HHV)[1]
Winter (24° F) (Full Load)	95.6	8,961
Summer (98° F) (Full Load)	86.4	9,360
Average (70° F and 72% relative humidity) (Full Load)	96.5	9,095
Average (70° F and 72% relative humidity) (75% Load)	72.1	9,543
Average (70° F and 72% relative humidity) (50% Load)	47.8	10,609

[1]Net capacity and full load net plant heat rate include degradation factors, evaporative cooling is not considered, and performance is preliminary.

Table 14-10
GE LMS100 Estimated Emissions[1]

NO_x, ppmvd at 15% O_2	2
NO_x, lb/MBtu	0.0072
SO_2, lb/MBtu	0.0005
Hg, lb/TBtu	N/A
CO_2, lb/MBtu	114.8
CO, ppmvd at 15% O_2	11.4
CO, lb/MBtu	0.025

[1]Emissions are at full load at 70° F and include the effects of SCR and CO catalyst.

14.1.4 GE 7FA 1x1 Combined Cycle

Combined cycle power plants use one or more CTGs and one or more STGs to produce energy. Combined cycle power plants operate according to a combination of both the Brayton and Rankine thermodynamic power cycles. HP steam is produced when the hot exhaust gas from the CTG is passed through an HRSG. The HP steam is then expanded through a steam turbine, which spins an electric generator. It is assumed that duct firing will be used in the combined cycle option.

Combined cycle configurations have several advantages over simple cycle combustion turbines. Advantages include increased efficiency and potentially greater operating flexibility if duct burners are used. Disadvantages of combined cycles relative to simple cycles include a small reduction in plant reliability and an increase in the overall staffing and maintenance requirements because of added plant complexity.

The 1x1 combined cycle generating unit includes one GE 7FA CTG, one HRSG, and one STG and will include evaporative cooling. The HRSG will convert waste heat from the combustion turbine exhaust to steam for use in driving the STG. The HRSG is expected to be a natural circulation, three-pressure, reheat unit with supplemental duct firing to maintain full steam turbine generator load at all ambient conditions. SCR and dry low NO_x burners will be included to control NO_x to 2 ppmvd, and space for a CO catalyst will be included.

The steam turbine is expected to be a tandem-compound, single reheat condensing turbine operating at 3,600 rpm. The steam turbine will have one HP section, one IP section, and a two-flow LP section. Turbine suppliers' standard auxiliary equipment; lubricating oil system; hydraulic oil system; and supervisory, monitoring, and control systems are included. A single synchronous generator is included, which will be direct coupled to the steam turbine. The STG will be located outdoors, with a building provided for the major auxiliary electrical power equipment.

Expected output, performance, and emissions for the 1x1 GE 7FA combined cycle alternative are the same as those of Cane Island 4, which is described in Section 10.0.

14.1.5 Capital Costs, O&M Costs, Schedule, and Maintenance Summary

The capital costs, O&M costs, schedule, forced outage, and maintenance estimates for the generating alternatives are summarized in Table 14-11. All costs are provided in 2008 dollars unless otherwise noted. The EPC cost includes engineering, procurement, construction, and indirect costs for construction of each alternative utilizing a fixed price, turnkey type contracting structure. The assumed owner's cost allowance is representative of typical owner's costs as outlined in Table 14-1, exclusive of escalation, financing fees, and interest during construction, which will be accounted for separately in the economic analyses.

Table 14-11
Capital Costs, O&M Costs, and Schedules for the Generating Alternatives
(All Costs in 2008 Dollars, Unless Otherwise Noted)

Supply Alternative	EPC Cost ($millions) [1]	Owner's Cost ($millions) [1]	Total Cost ($millions) [1]	Total Cost ($/kW) at 70° F	Fixed O&M ($/kW-yr)	Nonfuel Variable O&M ($/MWh)	Construction Schedule (months)	Scheduled Maintenance (days)	Forced Outage (percent)
GE LM6000 SC	44.3	11.1	55.3	1,169.8	26.47	3.64	10	10	2.0
GE LMS100 SC	69.3	17.3	86.7	898.3	13.45	3.29	12	10	2.0
GE 7EA SC	52.3	13.1	65.3	833.0	16.39	11.28	12	10	2.0
GE 7FA SC	83.1	20.8	103.9	649.4	8.41	15.57	12	10	2.0
1x1 GE 7FA CC [2]	Refer to Note (2)	Refer to Note (2)	421.6[3]	1,372.4[3]	4.56	3.30	22	14	2.0

[1]Unless otherwise noted, the total cost is an overnight 2008 estimate that does not include interest during construction.
[2]The estimated cost, availability, and construction schedule for the 1x1 GE 7FA CC are consistent with those presented for Cane Island 4 in Section 10. The 1x1 GE 7FA CC alternative is intended to represent a future unit alternative beyond the addition of Cane Island 4, not an alternative to the addition of Cane Island 4.
[3]The estimated capital cost for the 1x1 GE 7FA CC includes escalation and interest during construction and is presented in 2011 in-service dollars.

Fixed and nonfuel variable O&M costs are also provided in 2008 dollars. Fixed costs include labor, maintenance, and other fixed expenses excluding backup power, property taxes, and insurance. Nonfuel variable costs include outage maintenance, consumables, and replacements dependent on unit operation. Construction schedules are indicative of typical construction durations for the alternative technology and plant size. Actual costs and schedules will vary from the preliminary estimates provided in Table 14-11.

The scheduled and forced outage assumptions for the generating alternatives are also presented in Table 14-11.

15.0 Power Supply Request for Proposals

To evaluate potentially cost-effective power supply alternatives for the construction of Cane Island 4, FMPA issued a request for power supply proposals (RFP) on behalf of the ARP on June 22, 2007. The power supply RFP served as an invitation for qualified companies to submit proposals for the supply of capacity and energy to meet a portion of the projected power requirements of the ARP beginning on January 1, 2011, and continuing over a period of at least 10 years. The RFP requested a minimum of 50 MW (up to a maximum of 300 MW) and required that the proposed capacity and energy be delivered to the PEF transmission system.

The power supply RFP was distributed directly to 14 utilities and independent power producers. Additionally, the RFP was posted on FMPA's Web site, which allowed industry publications to pick it up for further distribution.

The RFP is presented in Appendix A.

15.1 Overview of the Power Supply RFP

The power supply RFP allowed for proposals for capacity and energy for contract periods of 10 years or greater from existing specified resources, a portfolio supply of resources with appropriate guarantees, or a generating facility or facilities to be constructed for a unit power sale. All proposals were required to identify specific resources at specific sites. The RFP also required that proposals based on resources outside the PEF transmission system identify the transmission contracts for the transmission path that would be utilized from the resource(s) to the PEF transmission system interface. For unit-contingent purchases, all available unit data (e.g., performance, availability, capacity, fuel type, etc.) for the specific unit(s) were required to be provided by the bidder.

The power supply RFP contemplated a bid and negotiate proposal evaluation process, with the information that was submitted by each qualified proposer (by the August 17, 2007 proposal due date) used to develop a short-list of proposals from which selection(s) could be made for negotiations. Qualified proposals would be evaluated on the basis of both pricing and nonpricing factors. The first stage of the evaluation process would include a comparison of each proposal submittal, with the following minimum requirements set forth in the power supply RFP:

1. For a generating unit power sale, FMPA's rights must be equal to or superior to any other party's rights to such unit(s) output (i.e., as long as the unit(s) from which the capacity is purchased is available, FMPA has the right to the output of the unit(s) for the duration of the contract).

2. All proposals for capacity must commence on January 1, 2011.
3. All proposals must have contract periods of not less than 10 years.
4. All proposals must remain in effect until December 6, 2007, or later if the purchase is to be finalized pending a transmission service request.
5. The capacity amount offered to FMPA shall be not less than 50 MW or greater than 300 MW. Acceptable offers from all proposers must total at least 300 MW for FMPA to proceed with purchases under this RFP. Proposals that require FMPA to provide natural gas must identify the natural gas delivery point.
6. All generating units providing the proposed capacity must be in commercial operation at least 2 months prior to the required delivery commencement date of the term of the proposed power supply.
7. Proposals must identify and include the location of each capacity resource and name the originating control area. Resources must be delivered to the PEF transmission system. Proposers proposing power supply from a resource(s) located outside of the PEF balancing authority must also identify the firm transmission contract path from the power supply(ies) to the PEF transmission system.
8. The proposer must commit in the proposal that all emissions allowance requirements will be satisfied and must include costs for emissions allowances in the proposal.
9. The proposer must declare ownership or contractual status of a unit or plant, as described in Section 15 of the RFP.
10. The proposer must complete the appropriate RFP forms and provide all appropriate information requested in Attachment B to the RFP. All forms requiring a signature must be signed by a duly authorized official of the proposer.
11. The proposer must commit in the proposal to provide an adequate Proposal Security prior to entering short-list negotiations and an adequate Performance Security upon execution of a contract, in accordance with Section 16 of the RFP.
12. Each proposal must clearly describe any contractual limits on energy utilization or physical limitations on the operation of the resource, as described in Attachment B of the RFP.
13. Each proposal must include scheduling provisions for the sale.
14. Each proposal must contain the appropriate Proposal Fee in accordance with Section 10 of the RFP.

15. Proposals for new construction projects must not be contingent upon participation by other third parties to support the project.
16. Proposers that propose to develop a power generating project to provide power to FMPA must have developed, and have had in operation for a minimum of 1 year, at least one currently operating power supply project that is similar to, or larger in size than, the project being proposed. Proposers offering to provide FMPA with power from an existing generating resource must have successfully provided similar levels of services to at least one electric utility for a minimum of 1 year.

15.2 Results of the Power Supply RFP

One of the requirements set forth in the power supply RFP was mandatory attendance at the pre-bid conference prior to submitting a response to the RFP. The mandatory pre-bid conference was held on June 28, 2007 at FMPA's offices in Orlando, Florida. No potential bidders attended the pre-bid conference, nor did any entities submit notices of intent to bid, which were required (as stated in the RFP) to be submitted no later than July 3, 2007. The schedule set forth in the power supply RFP required that all bids in response to the RFP be submitted by August 17, 2007. No bidders responded to the power supply RFP; therefore, the power supply RFP process was terminated on November 5, 2007.

16.0 Renewable Energy

FMPA recognizes the importance of integrating renewable energy into its power supply portfolio to serve the requirements of the ARP. In addition to existing renewable energy resources, several new renewable energy projects are currently being evaluated by FMPA. This section discusses existing renewable energy sources available to FMPA. In addition, this section discusses FMPA's request for proposals (RFP) for renewable capacity and energy and its RFP for solar photovoltaic (PV) equipment or power purchase agreements, as well as potential new renewable energy projects being evaluated by FMPA outside of the RFP processes. Through the RFP processes described below, FMPA has performed a thorough evaluation of reasonably available renewable energy sources.

16.1 Existing FMPA Renewable Energy Resources

FMPA purchases power on an as-available basis from a cogeneration plant owned and operated by the US Sugar Corporation that is fueled by sugar bagasse, a byproduct of sugar production. As US Sugar utilizes its renewable generating facility to serve its own energy requirements, the ARP also avoids having to serve the US Sugar load using more carbon intensive generating resources.

Landfill gas (LFG) obtained from the Orange County landfill is used as a supplemental fuel source in coal fueled Stanton Energy Center Units 1 and 2. FMPA has an ownership share in both Stanton Units 1 and 2.

Table 16-1 presents the historical annual quantities of energy purchased from the US Sugar facility and produced from FMPA's ownership share of Stanton Energy Center Units 1 and 2 using landfill gas.

Table 16-1
Historical Renewable Energy Generation – Existing ARP Renewable Resources

	Annual Energy (MWh)							
Resource	2000	2001	2002	2003	2004	2005	2006	2007
US Sugar	1,076	206	921	388	1,923	3,168	5,263	5,532
Stanton Energy Center (LFG)	0	27,754	25,527	29,069	29,945	25,706	19,882	(1)
Total	1,076	27,960	26,448	29,457	31,868	28,874	25,145	(1)

(1)Data for 2007 not yet available.

16.2 FMPA RFP for Renewable Capacity and Energy

On June 29, 2007, FMPA issued a RFP for Renewable Capacity and Energy (Renewables RFP) on behalf of the ARP. The Renewables RFP, which is presented in its entirety as Appendix B to this Application, served as an invitation for qualified companies to submit proposals for the supply of capacity and energy to meet a portion of the projected power requirements of the ARP beginning on January 1, 2011 or earlier and continuing over a period of at least 5 years. The RFP requested a minimum of 1.0 MW and required that the proposed capacity and energy be delivered to either the FPL or PEF transmission systems.

The renewable RFP was distributed directly to 26 entities and notification of the RFP was posted in 2 industry publications. Additionally, the RFP was posted on FMPA's website which allowed industry publications to pick it up for further distribution.

The Renewable RFP requested resources where the sole source of fuel used for the production of energy for sale to FMPA was from one or more of the following sources:

- Hydrogen produced from sources other than fossil fuels.
- Biomass (including waste to energy and landfill gas).
- Solar energy.
- Geothermal energy.
- Wind energy.
- Ocean energy.
- Hydroelectric power.
- Waste heat from a commercial or industrial process.
- Any other technologies utilizing fuel/energy sources deemed by FMPA to be renewable in nature.

The Renewables RFP contemplated a bid-and-negotiate proposal evaluation process, with information from each qualified proposer submitted in response to the RFP by the August 29, 2007 proposal due date used to develop a short-list of proposals from which selection(s) could be made for negotiations. Qualified proposals would be evaluated based on both pricing and non-price factors. The first stage of the evaluation process would include a comparison of each proposal submittal with the minimum requirements set forth in the power supply RFP, which were as follows:

1. The proposal contains the appropriate Proposal Fee in accordance with Section 9 of the RFP.
2. The proposal is for at least 1 MW and begins delivery no later than January 1, 2011.

3. The proposal shall remain valid to the later of March 28, 2008, or the date of receipt of all regulatory approvals required for the proposal and any related transmission service.
4. The proposal is priced inclusive of the Proposer supplying and arranging for all third party transmission into the FMPA system (qualified network resource under FPL's and/or PEF's Open Access Transmission Tariff) and located in the State of Florida. The Proposer has identified the means of assuring firm delivery of capacity resources.
5. The Proposer has agreed to pay for all necessary transmission upgrades to provide for interconnection and delivery service to the FMPA system.
6. For proposals involving a sale to more than one utility from the same resource(s), FMPA's rights to the output shall be equal to, or greater than, the rights of all other customers served by the resource(s).
7. The Proposer ensures that all emissions allowance requirements will be satisfied and that any associated costs shall be borne by the Proposer.
8. The Proposer demonstrates ownership or contractual rights to the generating system capacity identified as supplying the sale.
9. Resources providing the proposed capacity, whether an existing plant or proposed new resources, must be in operation at least two (2) months prior to the start date of the proposed power supply.
10. The Proposer has completed the appropriate RFP Forms 1 through 4. All forms requiring a signature must be signed by a duly authorized official representing the Proposer.
11. The Proposer has provided a Letter of Commitment to establish an acceptable Proposal Security as solely determined by FMPA within ten (10) days of being notified that his proposal is on the short-list of proposals.
12. Proposers shall have successfully provided under contract to at least one electric utility for a minimum period of one year, similar services to the services they are providing to FMPA and have included information in the proposal to demonstrate this experience.
13. The Proposer agrees to assist FMPA to obtain final contract approval from their respective governing bodies in public sessions, where required.
14. The Proposer agrees to provide a letter of commitment from a financial institution with a credit rating of at least A- by S&P, A3 by Moody's or A- from Fitch to be a guarantor for a Proposal Security to be established by the Proposer equal to five dollars ($5) per kilowatt (kW) of the capacity

offered in the proposal within ten (10) days of being notified that the proposal is on the short-list of proposals.

15. Pricing information must be provided by Proposers in sufficient detail for FMPA to fully analyze each proposal.
16. The Proposer must provide agreements and disclose sufficient information relating to the provision of fuels, critical spare parts, technical service and support, and maintenance plans to permit FMPA to evaluate the proposals for reliability.
17. If the Proposer is proposing an energy-only, must take, non-dispatchable, or any other arrangement that would require FMPA to take energy from the Proposer at levels that may not be scheduled by FMPA, then the proposal must contain a projected schedule of energy to be provided under the proposal. Such schedules must contain sufficient detail to permit an analysis of hourly energy patterns by day and month over the proposed contract period.

16.2.1 Summary of RFP Responses

The optional pre-bid conference was held on July 11, 2007 at the FMPA offices, and was attended by potential bidders. Of the attendees, six companies submitted a Notice of Intent to Bid Form on July 16, 2007. After receiving notice of intents to bid, each of the potential bidders was contacted to obtain additional information and to encourage them to follow up on their intent to submit a proposal. Three bids were submitted by the August 29, 2007 deadline. After receiving the bids, those proposers who had submitted the Notice of Intent to Bid but had not submitted a bid were contacted, but none decided to submit a proposal. The proposals received by FMPA included (i) a 58 MW summer rated biomass circulating fluidized bed (CFB) plant proposed to burn waste wood and other materials including recycled pallets, and paper derived fuel; (ii) 10 MW of roof-mounted PV systems; and (iii) a 1 MW to 3 MW centralized PV system.

16.2.2 Renewables RFP Response Evaluation Process

The first phase of the evaluation involved a screening of bids received with the minimum requirements as described in Section 20 of the Renewables RFP and as listed in Section 16.2. This evaluation, which was completed on September 12, 2007, indicated that two (2) of the proposals had not clearly met certain of the minimum requirements. Questions were submitted to the two proposers that had not clearly met all of the minimum requirements to obtain additional information. At this point, it was determined

that FMPA would continue to consider all three of the proposals received. A preliminary quantitative evaluation was completed for all three proposals on October 19, 2007. Based on the preliminary evaluation, FMPA short listed all three proposers and meetings were held with the proposers on October 31 through November 2 of 2007. After the meetings a second set of questions were submitted to the proposers. Responses to the questions were received between November 14, 2007 and November 27, 2007. The centralized PV proposer indicated that they could not support the original price offered and provided a higher price verbal offer. After the second set of responses to questions was received, the evaluations were updated.

The updated results were summarized in a report dated December 12, 2007, which indicated that the levelized busbar costs for the three renewable alternatives were projected to be above FMPA's avoided cost. The biomass proposal was projected to be the lowest cost of the three proposals on a dollar per MWh basis.

Nevertheless, in spite of their higher costs, FMPA decided to continue negotiations with two of the proposers as part of its commitment to renewable energy sources. As of the time of the updated evaluation, the bidder proposing the centralized PV system did not supply the required proposal security. As a result, no further meetings were held with this proposer.

After the preliminary screening update, meetings were again held with the rooftop PV and biomass renewable proposers. Prior to the meetings, the proposers provided draft agreements, which were reviewed at the meetings.

As a result of further negotiations, the rooftop PV proposer offered reduced pricing which was still above FMPA's avoided costs. FMPA is continuing negotiations with the rooftop PV proposer for an open-ended contract for up to 10 MW at FMPA's discretion. The proposer has agreed to continue discussions on this basis.

Negotiations with the biomass proposer have continued over the course of an additional three meetings during March and April 2008. FMPA has explored different pricing arrangements over the course of the negotiations.

FMPA's ARP Executive Committee has approved continued negotiations for a power purchase from the biomass facility. Because the cost of biomass energy is higher than FMPA's avoided cost, before entering into a final contract with the proposer, FMPA will need to assess the cost penalty associated with the project. Furthermore, FMPA's ultimate commitment to utilizing biomass energy to serve its energy requirements will depend on whether biomass continues to be considered a renewable and carbon neutral energy source in Florida. FMPA will also need to examine the actions of other utilities in Florida in meeting their renewable targets to ensure that FMPA's rates remain cost competitive. The time frame for implementation of a biomass resource would depend on

the time necessary to complete negotiations and obtain all required regulatory approvals and permits and approval of mutually agreeable commercial terms by FMPA.

FMPA's ARP Executive Committee also has approved continued negotiations for an open ended power purchase of up to 10 MW at FMPA's discretion from the roof-mounted PV systems bidder. While the cost of this alternative appears to be higher on a $/MWh basis than the least cost solar PV bid discussed in Section 16.3, there may be special circumstances for which roof-mounted PV systems would be desirable. Again, FMPA would need to assess the cost penalty associated with the project, and negotiate mutually agreeable commercial terms. FMPA intends that this contract work in concert with the contract discussed in Section 16.3 such that up to 10 MW in total of solar PV be installed.

In addition, FMPA received an unsolicited proposal from the centralized photovoltaic proposer on February 19, 2008. Because the proposed pricing was higher than other photovoltaic proposals that FMPA had received pursuant to the RFP for Solar PV Equipment or Power Purchase Agreements discussed in Section 16.3, this proposal was not pursued further.

16.3 FMPA RFP for Solar PV Equipment or Power Purchase Agreements

FMPA issued an RFP specifically for solar PV equipment or purchase power agreements (Solar RFP) on December 5, 2007 with a bid due date of January 7, 2008. The RFP in its entirely is presented in Appendix C. The bidders were invited to submit bids for the installation of 10 MW of solar PV capacity by the end of 2008, with the potential for up to 100 MW of solar PV capacity by 2013. The Solar RFP invited bidders to submit proposals ranging from the supply of PV equipment, to the installation of turnkey solar project, to a power purchase contract for energy generated by a solar system. Twenty-six bids were received – 12 offering a power purchase agreement (PPA), 13 offering turnkey, or EPC, installation of the equipment, and 7 offering to sell the equipment directly.

FMPA solicited the expertise of the Orlando Utilities Commission (OUC) staff, and Florida Solar Energy Center (FSEC) staff to be on a bid review team. The team met in January 2008 to review and rank the bids received in response to the solar RFP. The results of the review team meeting were compiled and finalized. A short list of eight proposals representing a mix of power purchase agreements, turnkey installations, and self build options was approved by the ARP Executive Committee in January 2008.

Further quantitative analysis was done on the eight responses. All of the proposals were found to be above FMPA's avoided costs and therefore more expensive than traditional resources. Consistent with Florida's environmental goals, however, FMPA is committed to developing a reasonably balanced mix of power resources including renewable technologies such as solar energy. FMPA staff's detailed evaluation showed the proposal of Sun Edison LLC to be the preferred proposal. This proposal was followed, in order, by Sunpower Corporation and then MMA Renewable Ventures. The Sun Edison proposal was structured as a 20 year power purchase agreement (PPA) so that there would be no up-front capital outlay. The Sunpower proposal was found to be very similar to Sun Edison in structure in that it was also proposing a PPA using FMPA sites. MMA Renewable Ventures proposed to develop their own site and sell energy to FMPA via a 20 year PPA. On March 27, 2008, the ARP Executive Committee approved the RFP ranking of proposals listed above.

On April 4, 2008, FMPA staff issued an e-mail soliciting interest from FMPA's ARP member cities to identify those members which might have an interest in locating a solar photovoltaic (PV) installation in their community. The various sites selected will require the execution of agreements between the property owner, FMPA, and the contractor.

Staff is currently working with Sun Edison to develop a contract to bring to the ARP Executive Committee for their approval in May 2008. Staff anticipates approval for the initial 10 MW. For PV capacity greater than 10 MW, the ARP will need to give significant consideration to the additional costs of PV compared to other alternatives and the actual performance of the initial 10 MW in the ARP system.

16.4 Additional Renewable Energy Resources

In addition to FMPA's existing renewable energy projects and the renewable energy resources being considered as part of the RFP processes described previously in this section, FMPA is considering participation in certain additional renewable energy projects as described below.

16.4.1 Bio-Fuels

FMPA is currently evaluating the feasibility of operating several of its generating units using bio-fuels. General Electric (GE) has reported that initial trials have proven satisfactory operation in several models of generation units. FMPA's initial investigation centers at the Stock Island facility in Key West, since all of the units located at that facility use fuel oil exclusively as the energy source.

Initial trials will be performed using three, 20 MW GE frame 5 combustion turbines. The tests will be based on 100 percent bio-diesel fuel or a blend of bio-diesel. As of the date this Application was prepared, fuel samples had been sent for testing to confirm the fuel's heat rate and contamination. The next step will be obtaining a permit for the testing from the Florida Department of Environmental Protection.

A major technical drawback under evaluation is performing the modifications necessary to store fuel and operate the units. Bio-fuel is a solvent and may react negatively with tank coatings, hoses, valves, and seals. The second major concern is that more fuel must be delivered to the machine to operate the unit for the same power output as conventional fuel.

16.4.2 Landfill Gas

FMPA is following the progress of the permitting and development of a major landfill gas generation facility to determine the feasibility of a long term contract for the electrical output. Landfill gas projects typically range in size between 1 MW to 10 MW. However, the prospective facility is planned for a 15 MW combustion turbine and is currently being permitted. FMPA is awaiting an update from the developer and may negotiate with the owner to receive the electric output.

16.4.3 Plasma Arc Technology

FMPA is evaluating a proposal for construction of a solid waste-to-energy facility using plasma arc technology at the St. Lucie County landfill with a target commercial operation date of 2011. The facility would treat and destroy solid waste created by the County either currently in its landfill or delivered to the landfill and generate synthesis gas (syngas). The intent would be for FMPA to purchase the syngas to burn in a combined cycle power plant to be constructed and operated by FMPA or develop a power purchase agreement for energy and capacity. FMPA has signed a Letter of Intent with the developer, Geoplasma, LLC.

16.4.4 Customer-Owned Renewable Resources

To assist in the development of renewable resources by customers of ARP Members, FMPA on behalf of its ARP Members is currently working towards developing standardized interconnection standards, agreements, and processes for net metering customer-owned renewable generation in ARP Member cities. The FMPA Executive Committee has held two workshops to discuss a net metering policy and implementation of the net metering policy for FMPA and the ARP members. FMPA anticipates the adoption before the fall of 2008 of an ARP net metering policy that will permit ARP

members to net meter, and permit the ARP to purchase energy for customer-owned renewable generation systems. Interconnection for customer owned renewable generating systems will be at distribution voltage levels pursuant to interconnection standards adopted by each ARP member.

17.0 Conservation and Demand-Side Management

FMPA recognizes the importance of encouraging its members to reduce electricity demand through conservation and demand-side management (DSM) programs. As a wholesale supplier, FMPA historically has not directly provided conservation or DSM programs to retail customers - such programs have been provided to the retail customers by the ARP members. This section discusses existing conservation and DSM programs currently offered by ARP members. In addition, this section discusses FMPA's request for proposals (RFP) for demand-side management resources (DSM RFP) as well as potential new conservation and DSM initiatives under consideration by FMPA outside of the DSM RFP process. As discussed below, ARP members are utilizing reasonably available conservation measures and are continuing to evaluate other conservation measures that may further reduce their energy demands.

17.1 Existing ARP Member Conservation and DSM Programs

ARP member cities currently offer several conservation and DSM programs. Table 17-1 presents a matrix of these programs. The details of the conservation and DSM programs are presented below. FMPA will continue to offer services as needed to assist members in increasing the promotion and use of conservation programs to retail customers and will assist all of its members in the evaluation of any new programs to ensure their cost effectiveness.

17.1.1 Energy Audit Programs

Several ARP member cities offer customers free energy audits of their home or business. Customers gain an understanding of why they consume their billed energy. The customer receives advice on ways to conserve and reduce their bill. The customer may be advised on the feasibility of installing more insulation or more energy efficient appliances.

As examples, Keys Energy Services provided 108 audits in 2007. While conducting an audit, the utility also offers to wrap water heaters with an insulating blanket. During 2007, Beaches Energy (City of Jacksonville Beach) performed 326 residential and commercial audits, Ocala performed 831 residential audits and 109 commercial audits, Havana provided 25 audits, KUA performed approximately 1,800 residential and commercial energy audits, Leesburg performed 35 energy audits, and Newberry performed approximately 10 energy audits.

Table 17-1
Existing ARP Member DSM Programs

	DSM Measures (1 of 3)					
	Energy Audit Program	Energy Saving Tips	Appliance and Other Rebates	Load Profiling for Commercial Customers	Fix-Up Programs	Tree Planting Incentive
Beaches	X	X				
Bushnell		X				X
Clewiston						
Fort Meade						
Fort Pierce	X	X			X	
Green Cove Springs		X				
Havana	X	X				
KEYS	X	X				X
KUA	X	X	X			X
Lake Worth						
Leesburg		X				X
Newberry						
Ocala	X	X	X	X	X	X
Starke						
Vero Beach		X				

	DSM Measures (2 of 3)					
	Solar Projects	Solar Promotion	Net Metering	On-Line Energy Audits	Green Energy	Compact Fluorescent Bulbs
Beaches			X	X		X
Bushnell				X		
Clewiston				X		
Fort Meade				X		
Fort Pierce						X
Green Cove Springs				X		
Havana						
KEYS	X	X	X	X	X	
KUA						X
Lake Worth				X		
Leesburg						
Newberry				X		
Ocala			X	X		X
Starke						
Vero Beach		X		X		

Table 17-1 (Continued)
Existing ARP Member DSM Programs

	DSM Measures (3 of 3)				
	ESCO Projects	City Wide Energy Conservation	Energy Star Program	Bio-Diesel Fleet	LED Traffic Signals
Beaches			X		
Bushnell					
Clewiston					
Fort Meade			X		
Fort Pierce		X	X		
Green Cove Springs			X		
Havana					
KEYS		X	X	X	X
KUA			X		
Lake Worth					
Leesburg	X	X	X		X
Newberry			X		
Ocala			X		X
Starke			X		
Vero Beach					

17.1.2 Energy Saving Tips

Advice on energy conservation is available from utility staff and or literature. For example, in addition to distributing traditional pamphlets, bill inserts and website information, Keys Energy Services works with the schools to promote conservation among students. Keys Energy Services hosts an annual conservation art contest and winning art work illustrates their conservation calendar. The utility also hosts theater shows on conservation to elementary students.

At Beaches Energy, a monthly newsletter with many energy saving tips is published and provided to customers. In the fall of 2007 four elementary schools participated in an art contest featuring energy conservation tips with the winners published in a calendar.

KUA provides free Energy Tips books and energy conservation calendars to its customers. These materials contain information on various ways that customers can conserve power. KUA also sponsors community activities and offers training to organizations.

The City of Clewiston runs a radio spot two to three times per week on a local radio station encouraging customers to have their heating and air conditioning systems inspected annually and to change the air filters regularly to reduce energy usage. The radio spot also encourages customers to contact the city for additional energy conservation tips.

17.1.3 Appliance and Other Rebates

The City of Ocala offers rebates to residential and small commercial customers to upgrade to more efficient heating, ventilation, and air conditioning (HVAC) units. Ocala also offers a residential attic insulation rebate. To date, 21 customers have participated in the HVAC rebate program, and 25 customers have participated in the attic insulation rebate program.

KUA has implemented a series of rebate programs for its customers. These programs include rebates for repairing duct leaks, performing annual maintenance of HVAC units, installing insulation in single-family homes and small businesses, and installing LED exit signs in businesses.

17.1.4 On-Line Energy Audits

Many of the ARP members offer an on-line energy audit service as a link from the city's web site. Each month, Webtrends provides activity data for the main FMPA Energy Depot website. The data is an overview of the FMPA site as a whole and represents a summation of the activity from all participating FMPA Member sites during

the month. Each participating Member also receives a report of new user profiles/audits on that Member's individual utility energy depot site. The Energy Depot Online Energy Audit includes the following features:

1. Personal Energy Profile--Allows customers to conduct online do-it-yourself home energy audits. Customers can choose from a comprehensive "Full Audit" or a quick "EZ Audit". The Energy Profile is a true home energy audit analysis with sound engineering calculations in a customer-friendly setting.
2. Energy Calculator--Allows customers to very quickly estimate the annual energy use and cost to operate the complete range of home electric and natural gas systems including everything from HVAC systems to minor appliances.
3. Energy Library--A systematically organized library of fact sheets on a wide range of home energy systems and efficiency opportunities. The library also includes the top 100 frequently asked questions and answers on home energy use.
4. Energy Advisor--An email question and answer tool that allows customers to receive answers to any remaining energy questions.

The total number of audits performed (EZ Audits or Full Audits) from the initial program startup in March 2007 through December 2007 was 1,659.

17.1.5 Load Profiling for Commercial Customers

The City of Ocala installs a recording meter to monitor the customer's electric consumption. Commercial customers can request monthly reports of their electric consumption profile.

17.1.6 Fix-Up Programs

Qualifying customers and homes can apply for assistance in having their home remodeled with additional insulation and weatherization. Fort Pierce Utilities Authority provides the energy audit for someone requesting consideration for home insulation upgrades. If the audit results in qualifying the home, a grant up to $10,000 is provided through the City of Fort Pierce. At present, 16 homes are being upgraded each year. The actual energy savings from the program are difficult to quantify, as some homes show significant improvement and others yield little benefit.

The City of Ocala has a similar program and retrofitted 44 homes during 2007.

17.1.7 ENERGY STAR® Program

Several ARP members participate in the ENERGY STAR® program and associated campaigns. ENERGY STAR®, which is backed by the US Environmental Protection Agency and Department of Energy, provides strategies and tools to help utilities promote different energy-saving campaigns. As an ENERGY STAR® partner, utilities recognize the importance of energy conservation in meeting their communities' power needs, minimizing customers' power bills, and conserving natural resources. Utilities participate in the ENERGY STAR® program by including links on their websites, posters and displays in their lobbies, as well as providing other promotional materials to their customers on ENERGY STAR® programs, appliances, conservation tools, and other features.

17.1.8 Compact Fluorescent Bulbs

Member cities that participate in this program give away and promote compact fluorescent light (CFL) bulbs to their customers. Since the fall of 2007, Beaches Energy has given away approximately 15,000 promotional CFL bulbs to residential and commercial customers.

17.1.9 ESCO Projects

An ESCO company is an energy services company specializing in the installation of energy efficient projects. The company provides professional energy auditing services and will arrange for financing and installation of projects for the customer. The ESCO is paid for its services through proven savings on energy. ARP Members participate in the program through a contract executed by FMPA.

As an example, the City of Leesburg had energy audits of the city's buildings performed by FMPA's ESCO affiliate. The initial projects undertaken had less than a four year payoff.

Lake/Sumter Community College is an electric customer of the City of Leesburg. A similar energy audit on the campus identified $500,000 in worthwhile projects. The City of Leesburg used a pooled loan provided by FMPA to provide a low interest loan to the Community College to support the implementation of the activities recommended by the energy audit.

17.1.10 City Wide Energy Conservation

Some member cities have set an example of energy conservation to their communities by implementing conservation projects throughout city owned facilities. As an example, the City of Jacksonville Beach has installed CFL bulbs where applicable in city facilities and installed sensor lighting in closets and rest rooms.

17.1.11 LED Traffic Signals

Several cities have undertaken a conservation measure to convert their traffic signals from using incandescent bulbs to bulbs made with light emitting diodes (LED).

17.1.12 Green Initiatives at FMPA Facilities

FMPA's headquarters in Orlando was designed for energy efficiency. This includes providing natural lighting along with energy efficient indirect lighting. The building's HVAC system is composed of a chilled water system and a variable air volume air distribution system. The building was constructed of lightweight, highly insulated material, which slows heat gain. The facility includes ENERGY STAR® certified appliances and office electronics.

17.2 FMPA RFP for Demand-Side Management Resources

On July 27, 2007, FMPA issued a Request for Proposals (RFP) for Demand Side Management resources (DSM RFP) on behalf of the ARP. The DSM RFP, which is presented in its entirety as Appendix D to this Application, served as an invitation for qualified companies to submit proposals for DSM resources. DSM resources include any facility, program, or service implemented for retail customers that serves to permanently reduce or shift the time of consumption of electric energy and/or electric demand. The RFP requested a minimum contract term of one-year beginning no earlier than June 1, 2008. On-peak demand and reductions must be at least 1,000 kW for third party proposers, and 500 kW for customer proposers.

The DSM RFP was distributed directly to 35 DSM providers and notification of the RFP was posted in one industry publication. Additionally, the RFP was posted on FMPA's website which allowed industry publications to pick it up for further distribution.

The following provides a listing of some of the information required to be submitted in response to the DSM RFP:

1. A listing of previous clients that have received similar services to those outlined by the RFP. The listing was to include a description of the DSM resource offered, the amount of capacity or energy involved, and a contact name and telephone number. The RFP advised potential respondents that preference will be given to firms with demonstrated experience with Florida municipal utility clients.

2. Firm name, description of core business services and primary client base and the name of the firm's parent company, if applicable. If the firm has an office in Florida, they were to give the location (address and phone number) and identify the office(s) that will be assigned to this project. If the respondent is an affiliation of two or more independent companies, they were to identify each company, their role in this project, and to provide the information described above for each company.

3. Proposals were required to include a pricing proposal, describing the payments the Proposer expected to receive over the term of the Agreement. The pricing proposal also was required to include:
   - An annual capacity price in $/kW for the amount of reduced demand, as well as an annual energy price in $/MWh for the amount of reduced energy. The RFP advised that the proposed demand and energy pricing should be net of any retail rate savings that the Host Customer(s) may receive that result from the demand and energy reductions.
   - A description of how the results obtained from the Measurement and Verification plan (M&V Plan) would be used to adjust payments made to the proposer over the term of the proposal.
   - An assessment of costs to be incurred by the Host Customer for the implementation of the DSM Measure(s).
   - Documentation of the derivation of the Host Customer costs for use in the economic evaluation of the Proposal.

4. Proposals were required to include an effective Measurement and Verification Plan (M&V Plan) to provide the basis for determining the level of demand and energy reductions produced as a result of the DSM Measure implementations. The M&V Plan was required to fully describe all calculations and procedures that will be used to determine demand and energy reductions, including, but not limited to: engineering estimates; auditing procedures; pre- and post-installation metering facilities and monitoring and recording procedures; quality assurance procedures; weather adjustments; and any other assumptions or measurements proposed by the Proposer. Additionally, the Proposer was required to describe how each of the following factors are addressed by the M&V Plan: Free Riders (as defined in Appendix A of the RFP), Free Drivers (as defined in Appendix A of the RFP), Persistence of reduction, consumption

rebound, state and federal efficiency standards and codes, diversity of demand reductions, coincidence with on-peak demands, naturally occurring conservation, degradation of DSM Measure efficiency, age of existing equipment/facilities to be affected by the DSM Measure(s), and projected demand and energy impacts of the existing facilities over the term of the proposal. The RFP also advised potential respondents that they would be expected to submit an annual report on demand and energy reductions, which are calculated consistent with the M&V Plan, prior to receipt of any demand and energy payments to be made by FMPA.

17.2.1 Summary of RFP Responses

FMPA received four (4) proposals by the September 26, 2007 due date specified in the DSM RFP. Of the proposals received, three offered programs to reduce FMPA's capacity or energy requirements – two using demand-response and the third through an ESCO arrangement. The fourth proposal was an offer to provide computer software and equipment, which was not the type of proposal being sought by FMPA. The three proposals retained for evaluation are described below.

The first demand response type proposal was projected to reduce the ARP's peak demand by 20 MW - 35 MW over a 5-year period. FMPA would pay a contractual rate for demand and energy reductions. The bidder would monitor FMPA's load from its 24 hour centralized control center and would curtail load when notified by FMPA. The bidder would bear the cost associated with monitoring and equipment installations. The bidder would guarantee MW reductions and would pay FMPA penalties for failure to deliver the reductions. Reductions would be measured against average kW usage during peak periods over the three highest usage days of the last 10 days.

The second demand response bidder's current offer is up to 44 MW of demand reduction over an 8-year period. The bidder would curtail load when notified by FMPA. The curtailment would be measured against the average of the participating facilities' single highest hourly demands for each of the four summer months of the previous year. The payment to the customer for the curtailment would be based on the average curtailment for all hours of the events occurring during the month. The bidder would guarantee MW reductions and would pay FMPA penalties for failure to deliver the reductions. FMPA would be responsible for metering costs for each participating customer.

The proposed ESCO arrangement would set up an ESCO that would work directly with ARP members' customers such as schools, colleges, and large commercial and industrial customers to reduce energy usage by changing equipment, sequence of

operation, or run times to reduce a customer's energy use. The customers would pay for a guaranteed level of energy reduction that would be guaranteed by the proposer.

17.2.2 DSM RFP Response Evaluation Process

On October 26, 2007, FMPA submitted clarifying questions to the three qualified proposers described previously. Responses to the questions were received over the period November 3, 2007 through November 20, 2007. Based on these responses, FMPA completed an evaluation of the DSM proposals on December 3, 2007. The evaluation compared pricing for each of the definitive proposals against the cost of conventional capacity. FMPA concluded that both of the demand response proposals offered definitive proposals for demand response programs that were projected to reduce the ARP's demand. Of these two, the pricing for one of the proposals was clearly lower and could potentially reduce FMPA's demand related costs compared to supply-side alternatives. The third proposal, the ESCO, did not provide a specific energy reduction or pricing after clarifying questions had been asked except to project that participating customers could reduce energy consumption by 15 percent to 20 percent. None of the proposals offered definitive energy efficiency or conservation programs.

Based on the initial evaluation of the DSM proposals, FMPA decided to meet with the three qualified DSM proposers to further clarify DSM programs that could reduce FMPA's costs and potentially help FMPA reduce greenhouse gas emissions. FMPA met with all of the proposers in January 2008 and has followed up with all of them with further meetings and/or phone calls. FMPA continued to negotiate agreements with all three proposers.

In order to evaluate both price and non-price attributes of each of the demand response program proposers, FMPA prepared a comparison matrix including such non-price factors such as measurement and verification of the curtailment, notice requirement, technical approach, local office presence, etc. Based on this review, both were approved for further negotiation. In addition, FMPA is continuing discussions with the ESCO proposer relating to their energy efficiency/conservation type proposal.

Based on responses to the DSM RFP and subsequent discussions with proposers, FMPA is examining the possibility of implementing a demand response program that, based on information provided by one of the proposers, could potentially reduce the ARP coincident peak demand by approximately 44 MW by 2016, with the following assumed implementation schedule:

- 15 MW in 2009.
- 7 MW in 2010 (22 MW cumulative).
- 4 MW in 2011 (26 MW cumulative).
- 4 MW in 2012 (30 MW cumulative).
- 4 MW in 2013 (34 MW cumulative).
- 4 MW in 2014 (38 MW cumulative).
- 4 MW in 2015 (42 MW cumulative).
- 2 MW in 2016 (44 MW cumulative).

At this point FMPA envisions that curtailment could occur between noon and 8:00 p.m. between the months of May and October. Up to six hours continuous could be curtailed, with maximums of up to 30 hours curtailed in any month and up to 60 hours curtailed in total during a calendar year.

17.3 Additional Conservation and DSM Initiatives

FMPA is considering several conservation and DSM initiatives in addition to those described previously in this section.

17.3.1 Publix Demand Response Program

FMPA has been working with Publix Super Markets on a demand response program. The program would call for Publix to receive a notice from the FMPA dispatch center and turn on their standby generators during peak load periods and system emergency load periods. This program is similar to the programs that investor owned utilities have implemented with Publix and other major commercial enterprises with large standby generators. The benefit of the program to Publix is that the company is paid an incentive in line with FMPA's avoided cost. As Publix must exercise its generators regularly, this generates no net increase in greenhouse gases while avoiding the generation of greenhouse gases and other emissions on the utility's part. The use of Publix standby generators would be during periods that the utility would otherwise be forced to use generation from its more inefficient units.

17.3.2 Potential ARP-Funded Energy Conservation Program

FMPA is considering undertaking a program to assist its Members in implementing energy conservation measures. Under this program, FMPA could collect funds through its rates that would be allocated among the ARP Members. As an example, the Members could utilize these funds to purchase CFL bulbs that could be distributed to retail customers at reduced or no cost.

17.3.3 Florida Municipal Energy Efficiency Coalition

FMPA is a member of a new group of Florida public power utilities, called Florida Municipal Energy Efficiency Coalition (FMEC). This group was formed in August of 2006 to explore new options for efficiency programs that can result in greater energy conservation and savings to customers. Other members of FMEC are Gainesville Regional Utilities, JEA, Lakeland Electric, Orlando Utilities Commission, Tallahassee, and Florida Municipal Electric Association. The utilities have agreed to develop consistent data and share best practices as they evaluate DSM programs to save energy that are specific to the state of Florida.

17.3.4 Florida Energy Sustainability Consortium

FMPA is also participating in the Florida Energy Sustainability Consortium. The consortium, made up of Florida universities together with industry, proposes a statewide collaboration to coordinate and unify efforts in research, development, technology commercialization, education, outreach, and technology transfer in energy.

FMPA believes the Florida Energy Sustainability Consortium will bring substantial benefits to the Member cities and the communities they serve. FMPA expects the Consortium to help it build consensus and understanding of issues related to the state proposed GHG reduction program. Likewise, FMPA believes that Florida must pull together the best ideas from energy production, emission control, generation efficiency, customer efficiency and renewable production. It is FMPA's understanding that the Florida Energy Sustainability Consortium will not only bring utility representatives together but representatives from state agencies as well as representatives from various other industry sectors.

17.3.5 Demonstration of Energy-Efficient Developments Programs

FMPA is also a member of the American Public Power Association's Demonstration of Energy-Efficient Developments (DEED) program. Through FMPA's membership in this program, all of FMPA's members are also DEED members. DEED is a research and development program funded by and for public power utilities. Established in 1980, DEED encourages activities that promote energy innovation, improve efficiencies, and lower costs of energy to public power customers.

18.0 Carbon Reduction Activities

18.1 Introduction

On July 13, 2007, Governor Crist issued Executive Order 07-127, entitled "Immediate Action to Reduce Greenhouse Gas Emissions within Florida." This order directs the Department of Environmental Protection (DEP) to adopt rules requiring CO_2 emission reductions from electric utilities. Although the DEP has not yet adopted any rules in response to the Governor's order, the ARP is committed to responsibly reducing its CO_2 emissions. This section summarizes the ARP's historical CO_2 emissions, as well as actions the ARP has taken or may take that will help reduce the ARP's CO_2 emissions. Specifically, Section 18.2 summarizes the ARP's carbon footprint. Section 18.3 summarizes actions the ARP has taken that will reduce the ARP's CO_2 emissions. Finally, Section 18.4 summarizes future planned actions, including the addition of Cane Island Unit 4, as well as other potential actions that would reduce the ARP's carbon footprint.

18.2 The ARP's Carbon Footprint

The Governor's Executive Order 07-127 sets goals for utilities to reduce their greenhouse gas emissions to 2000 levels by 2017, to 1990 levels by 2025, and by 80 percent of 1990 levels by 2050. This section describes a preliminary CO_2 emissions inventory developed for 1990 and 2000 to determine the baseline carbon footprint of the ARP in those years.

18.2.1 Methodology

Because the DEP has not established any guidelines on reporting of greenhouse gases as of the date of this filing, the emissions inventory was performed using the guidelines set forth in the DOE's final "General Guidelines for Voluntary Reporting of Greenhouse Gases (1605(b)) Program" issued in April 2006, and "Technical Guidelines for Voluntary Reporting of Greenhouse Gases (1605(b)) Program" (the Technical Guidelines) issued in January 2007.[1]

[1] The DOE initiated the Voluntary Reporting of Greenhouse Gases Program (the GHG Program) during 1994 in response to Section 1605(b) of the Energy Policy Act of 1992, which required the DOE to issue guidelines establishing such a program. The DOE developed both general guidelines and technical guidelines for the GHG Program. The technical guidelines define the permissible methods of calculating and reporting emissions quantities and reductions under the GHG Program.

The 1605(b) Guidelines categorize emissions for electric utilities as occurring from either direct or indirect sources. Direct emissions are those emissions that the utility is directly responsible for producing; that is, the utility produces these emissions through operation of its own generating units. Indirect emissions are those emissions associated with purchased power.

The collective 1990 and 2000 emissions for all 15 ARP members were developed using the equity share approach set forth in the 1605(b) Guidelines. Under this approach, a utility includes the percentage of the total emissions produced from a jointly owned facility that corresponds with its ownership percentage of that resource.

Where available, data from continuous emissions monitors (CEMs) were used to estimate direct emissions. However, as CEMS were not required to be installed on plants until after 1990, these data were not available for the 1990 computation. Additionally, some small generating units are not required to install CEMS, so CEMs data were not available for all generators for 2000. Where CEMs data were not available, emission factors provided in the 1605(b) Guidelines or other publicly available sources were used. Likewise, such publicly available emission factors were used to estimate emissions from purchase power.

18.2.2 Final Adjustments

The first step in determining the total emissions quantities for each year involved determining whether all energy sources had been captured for that year. The sum of all energy generated and purchased, net of wholesale energy sold to other entities, theoretically should be at least equal to the utility's energy requirements (some excess of energy sources above energy requirements may exist because of losses).

For computing total generation associated with direct emissions, the generation and consumption data from Global Energy Decisions' *Velocity Suite* were used for all units. This provided a consistent source of generation for all resources.

For both 1990 and 2000, however, the sum of the total energy sources amounted to less than the total energy requirements. For purposes of the analysis, CO_2 emissions were computed for the "missing" energy amount using the regional emissions factor assigned to purchased power for that year.

18.2.3 Emissions Totals

The total CO_2 emissions inventoried consist of the sum of the direct emissions, indirect emissions, and any adjustments. The computed total CO_2 emissions are shown in Table 18-1.

Table 18-1
Summary of ARP CO_2 Emissions in 1990 and 2000[1]

Item	Units	1990	2000
Total Energy Sources	GWh	3,142	6,426
Total Energy Requirements	GWh	4,663[2]	6,467
Surplus/(Shortfall)	GWh	(1,521)	(41)
Surplus/(Shortfall)	%	(32.6)	(0.6)
Direct CO_2 Emissions	000 Short Tons	1,442	2,538
Indirect CO_2 Emissions	000 Short Tons	836	2,139
Adjustments[3]	000 Short Tons	1,203	30
Total CO_2 Emissions	000 Short Tons	3,481	4,707

[1]Analysis performed as if all 15 current ARP members were ARP members in 1990 and 2000.
[2]Energy requirements estimated for 1990. Actual energy requirements for the ARP members in 1990 were not available.
[3]Adjustments reflect CO_2 emissions computed for additional energy amounts necessary to balance total energy sources and total energy requirements and were computed using the regional emissions factor assigned to purchased power for Florida applicable to that year.

18.3 Historical Carbon Reduction Activities

18.3.1 Generation Efficiency

Historically, the ARP has consistently sought to improve the efficiency of its generating fleet, which can have the added benefit of reducing carbon intensity (quantity of CO_2 per unit of energy produced). The ARP's actions have displaced generation from older, member-owned generating resources with newer, more efficient units. Table 18-2 below contains a list of the units that either have been or are scheduled to be retired, the retirement year, and the average CO_2 emissions eliminated by retiring these resources. Additional member-owned generation will be displaced with operation of Cane Island Unit 4.

Table 18-2
Recent and Scheduled Retirements of Member-Owned Generating Resources

Unit Name	Owner	Fuel Type	Retirement Year	Annual CO_2 Emissions (Short Tons)[1]
Hansel IC 8, 14-20	KUA	No. 2 Oil	2005	1,800
Big Pine Key IC 1	Keys Energy Services	No. 2 Oil	2006	400
Cudjoe Key IC 2-3	Keys Energy Services	No. 2 Oil	2006	1,500
H. D. King CC 5/9	Fort Pierce	Natural Gas	2008	11,100
H. D. King ST 7-8	Fort Pierce	Natural Gas	2008	20,400
H. D. King IC 1-2	Fort Pierce	No. 2 Oil	2008	200
Total				**35,400**

[1]Based on the average annual tons of CO_2 emitted during the years 2001 through 2005.

As appropriate and cost effective, FMPA has also sought to replace energy obtained from purchased power with more efficient means. Emissions for purchased power that are not tied to specific generating plants or units can be much higher than the carbon intensity of energy produced by efficient, natural gas-fired resources. As examples, FMPA has either recently replaced or is planning to replace energy from purchases from the City of Lakeland, Progress Energy Florida (PEF), and Florida Power & Light Company (FPL) with new generating resources or purchases from specific, gas-fired facilities.

FMPA has added several new generating resources in recent years through both ownership and facility-specific purchased power contracts. These new resources provide CO_2 emission reduction benefits to the ARP by allowing the ARP (1) to displace the operation of other, less efficient owned generating resources, and (2) to reduce the amount of more carbon-intensive energy it purchases from other entities. These new resources are described in more detail below.

- **Cane Island CC3**. Cane Island CC3 commenced operation in 2002. This 246 MW, natural gas-fired, combined cycle facility is jointly owned by KUA and FMPA, with all of its output going to the ARP. During its first 5 years of commercial operation, Cane Island CC3 emitted an average of approximately 0.21 short tons of CO_2 per MWh less than other ARP generating resources and approximately 0.22 short tons of CO_2 per MWh less than all energy sources for the ARP.

- **Stanton Energy Center CCA**. Stanton Energy Center CCA commenced operation in 2003. KUA and FMPA each owns a 3.5 percent share of this 600 MW, natural gas-fired, combined cycle facility, and each also purchases an additional 6.5 percent share from Southern Company, with the total 20 percent share going to the ARP. During its first 3 complete years of commercial operation, Stanton Energy Center CCA emitted an average of approximately 0.26 short tons of CO_2 per MWh less than other ARP generating resources and approximately 0.28 short tons of CO_2 per MWh less than all other energy sources for the ARP.
- **Calpine (Osprey) Purchase**. FMPA has a contract with Calpine that provided 75 MW in 2006. The purchase increased to 100 MW in 2007 and expires in 2009. During 2006, each MWh of energy purchased from Calpine produced approximately 0.19 short tons of CO_2 less than the average of the ARP generating units and approximately 0.23 short tons of CO_2 less than other purchases.
- **Stock Island CT4**. In 2006, the ARP commenced operation of its Stock Island CT4 in Key West. If operating at full load, every MWh of energy generated from Stock Island CT4 in lieu of other on-island resources can reduce FMPA's CO_2 emissions output by up to 0.17 short tons.
- **Southern Purchase**. FMPA has a contract to purchase 156 MW of new peaking power from Southern Company's Oleander plant beginning in December 2007. Since the unit has only been in operation since December 2007, actual emission data are not yet available; however, as a new efficient GE 7FA simple cycle combustion turbine, the Oleander purchase will reduce CO_2 emissions compared to other less efficient FMPA peaking resources or purchased power.

FMPA also currently receives renewable energy from two renewable resources. These resources also provide CO_2 reduction benefits to the ARP, as described below.

- **U.S. Sugar**. Energy purchased from the U.S. Sugar Corporation is considered carbon neutral because it uses renewable, carbon-neutral bagasse as its primary fuel source. Over the period 2000 through 2006, the U.S. Sugar purchase is estimated to have reduced CO_2 emissions for the ARP by an average of approximately 1,300 short tons per year. As U.S. Sugar utilizes its generating facility to serve its own energy requirements, the ARP indirectly avoids having to serve the U.S. Sugar load using more carbon intensive generating resources.

- **Landfill Gas (Stanton Energy Center)**. The Stanton Energy Center utilizes landfill gas to supplement the fuel requirements for the coal fired Units 1 and 2. The reportable CO_2 content for landfill gas/municipal solid waste (MSW) varies according to the plastic content of the underlying waste product. The national average CO_2 emissions factor for MSW (as provided by the DOE) is 92 pounds of CO_2 per MBtu of MSW consumed and is based on a plastic content of 16 percent. As the plastic content of the landfill gas burned by Stanton Energy Center Units 1 and 2 could not be obtained, the default factor was assumed. On the basis of this factor, CO_2 emissions for the ARP were estimated to have been reduced by approximately 19,700 short tons per year over the period 2001 through 2006 by consuming landfill gas instead of coal.

18.3.2 Demand Side Management

FMPA is a wholesale supplier of electricity to the 15 ARP member cities. As such, FMPA does not directly implement DSM to retail customers. The individual ARP members actually provide the DSM programs to their customers. Several ARP members offer various DSM programs, including the following:

- Energy audits.
- Energy savings tips.
- Energy Star programs.
- Green energy programs.
- Solar projects and net metering.
- Solar promotion.
- Appliance rebates.
- Compact fluorescent bulb promotions.
- ESCO projects.
- City-wide energy conservation.
- LED traffic signals.
- Load profiling for commercial customers.
- Fix-up programs for the elderly and handicapped.

To the extent these measures help to reduce FMPA's energy requirements, they have a corresponding CO_2 reduction benefit to the ARP.

18.4 Future Planned and Potential Carbon Reduction Activities

18.4.1 Treasure Coast Energy Center

FMPA's Treasure Coast Energy Center Unit 1 (TCEC Unit 1) is scheduled to commence operation in May 2008. This nominal 300 MW, natural gas-fired combined cycle unit represents FMPA's largest self-owned generating project to date. It is estimated that TCEC Unit 1 will reduce FMPA's CO_2 emissions by displacing less efficient generating units and power purchases on FMPA's system.

18.4.2 Cane Island Unit 4

Cane Island Unit 4 also will significantly reduce FMPA's total future CO_2 emissions. Cane Island Unit 4 will displace the operation of less efficient generating resources. By operating this more efficient unit, FMPA will reduce the average CO_2 emitted per MWh produced for its system. Additionally, Cane Island Unit 4 will reduce FMPA's purchase power requirements and associated higher CO_2 emissions.

Additionally, the need for Cane Island Unit 4 resulted from the cancellation of the Taylor Energy Center (TEC), the coal fired project that was jointly proposed by FMPA, JEA, Reedy Creek Improvement District, and the City of Tallahassee. The CO_2 emissions rate for the TEC was estimated between 200 and 215 lb/MBtu, or between 0.92 and 0.99 short tons/MWh based on the average heat rate of 9,238 Btu/kWh, depending on the type of coal consumed. By contrast, the estimated CO_2 emissions rate for Cane Island Unit 4 of approximately 115 lb/MBtu, or 0.43 short tons/MWh based on the average heat rate of approximately 7,420 Btu/kWh (including duct firing), is significantly lower.

18.4.3 Nuclear Uprates

FMPA's capacity shares of the Crystal River 3 and St. Lucie 2 nuclear units will increase as a result of upgrades to the facilities being undertaken by PEF and FPL, respectively. FMPA or members that own shares of these facilities will receive proportional increases in their capacity allotments based on their ownership percentage. The total planned incremental capacity increase for each unit and the ARP members' allocation of these capacity increases are shown below.

	Crystal River 3		St. Lucie 2	
	Total Uprate	ARP Allocation	Total Uprate	ARP Allocation
2008	12 MW	0.3 MW	--	--
2009	28 MW	0.8 MW	--	--

	Crystal River 3		St. Lucie 2	
	Total Uprate	ARP Allocation	Total Uprate	ARP Allocation
2010	--	--	--	--
2011	140 MW	4.0 MW	--	--
2012	--	--	100 MW	5.8 MW

This increase in nuclear capacity will provide a CO_2 emissions reduction benefit to FMPA.

18.4.4 Future Nuclear Ownership

FMPA is currently investigating the feasibility of acquiring an ownership share in future nuclear resources proposed to be built in Florida as discussed in Section 19.4. FMPA is currently in discussions with PEF concerning potential participation in the Levy County nuclear project. Since nuclear generation does not produce CO_2, acquiring additional nuclear ownership could bring significant CO_2 emissions reduction benefits to the ARP as early as 2016.

18.4.5 System Loss Reduction

FMPA encourages the concept of asset management for both itself and member utilities. Asset management involves investigating methods of utilizing existing assets to improve efficiency, lower costs, or improve revenue. CO_2 reductions can be obtained through management of the ARP's generating assets and aggregated electrical load.

Losses are an aggregated component of the electric load of the member utilities. As losses are controlled and reduced, so is the need for additional electrical generation. Therefore, reducing losses reduces CO_2 emissions and can reduce or delay the need for constructing additional generating resources. FMPA is leading an effort among the members to investigate losses and for members to invest in loss reduction.

18.4.6 Potential Future Renewable Resources

18.4.6.1 Potential Biomass Generation. As part of its efforts to reduce its overall CO_2 emissions, FMPA has issued RFPs for renewable resources as discussed in Section 16.0. Based on the results of the RFPs, FMPA has decided to enter into negotiations for a purchase from a biomass facility. The biomass unit, which would utilize renewable, carbon-neutral resources, would further reduce FMPA's CO_2 emissions. As discussed in Section 16.0, however, there are several issues that must be resolved before FMPA can commit to the potential biomass purchase.

18.4.6.2 Potential Solar Photovoltaic Project. FMPA has decided to enter into negotiations for the installation of 10 MW of solar PV technology on ARP member systems as discussed in Section 16.0. However, there are several issues that must be resolved before FMPA can commit to the PV purchase, as discussed in Section 16.0. FMPA will additionally explore the feasibility of acquiring up to an additional 90 MW of PV systems. The addition of PV systems would further reduce FMPA's CO_2 emissions. FMPA's decision to pursue additional solar capacity beyond the initial 10 MW would depend on successful negotiation for and implementation of the initial 10 MW project. The time frame for implementation of solar capacity would depend on the time necessary to complete negotiations and obtain all required regulatory approvals and permits.

18.4.6.3 Potential Use of Biofuels at Stock Island. FMPA is currently investigating the feasibility of operating several of the generating units at the Stock Island facility in Key West using biodiesel fuel. These units currently operate using fuel oil. If ultimately implemented, the switch from fuel oil to biodiesel fuel for these units could reduce FMPA's CO_2 emissions.

18.4.7 Potential Future Conservation Programs

18.4.7.1 DSM Request for Proposals. In July 2007, FMPA issued an RFP for DSM activities as discussed in Section 17.0. Four proposals were received, and FMPA is continuing to negotiate with three of the proposers. To the extent any of these measures, if ultimately implemented, help to reduce FMPA's future energy requirements, they would have a corresponding CO_2 reduction benefit to the ARP.

18.4.7.2 Potential ARP-Funded Energy Conservation Program. As a wholesale energy provider, FMPA does not directly implement demand-side conservation measures. However, FMPA is considering undertaking a program to assist its members in implementing energy conservation measures. Under this program, FMPA could collect funds through its rates that would be allocated among the ARP members. As an example, the members could utilize these funds to purchase compact fluorescent light bulbs that could be distributed to retail customers at reduced or no cost. These measures would help to reduce FMPA's energy requirements, which would have a corresponding CO_2 reduction benefit to the ARP.

18.5 Conclusion

The ARP has demonstrated a strong track record in improving the efficiency of its generating fleet, and it is committed to exploring new ways to improve efficiency and to reduce CO_2 emissions in a cost-effective manner. Because Cane Island Unit 4 will be one of the most efficient generating units in the state, it will enable the ARP to displace

generation from less efficient units and thereby reduce CO_2 emissions. While the specifics of any state CO_2 regulatory regime will not be known for some time, FMPA's preliminary analyses indicate that the least cost expansion plan with Cane Island Unit 4 would enable FMPA to achieve the 2017 CO_2 emissions target level in Executive Order 07-127.

19.0 Evaluation Methodology

Detailed economic analyses were performed to evaluate the economics of Cane Island Unit 4 as part of FMPA's least-cost expansion plan to satisfy forecast capacity requirements throughout the 20 year evaluation period considered in this Application. This section discusses the evaluation methodology used in the economic analyses. The result of the analyses are presented in Section 20.0.

19.1 Expansion Planning Simulation

Optimal generation expansion planning and production cost modeling was performed using STRATEGIST, a computer software system developed by NewEnergy Associates, LLC (NewEnergy). STRATEGIST is a proven and effective modeling program for optimal generation expansion planning and production cost modeling. According to NewEnergy, over 50 utilities now use STRATEGIST for integrated corporate strategic planning, including least-cost expansion planning. NewEnergy was recently acquired by Ventyx.

STRATEGIST includes an automatic expansion planning module that can determine the optimal balanced demand and supply plan for a utility system under a prescribed set of constraints and assumptions. STRATEGIST evaluates all combinations of generating unit alternatives and purchase power options in conjunction with existing capacity resources to satisfy forecast capacity requirements while maintaining user-defined reliability criteria. STRATEGIST simulates the hourly operation of a utility system to determine the cost and reliability effects of adding resources to the system or modifying the load through DSM programs. The simulation of the utility system operation is accomplished using dynamic programming, a mathematical technique useful for making a sequence of interrelated decisions for determining the combination of decisions that optimizes the desired outcome. In this Application, all expansion plans were analyzed over a 20 year period from 2008 through 2027.

19.2 Fuel and Emission Allowance Price Forecasts

Section 7.0 presents the fuel and emissions allowance price forecasts used throughout this Application, including price forecasts for various sensitivity cases. The fuel and emissions allowance price forecasts presented in Section 7.0 were developed in constant 2005 dollars. For purposes of the economic analyses presented throughout this Application, the constant 2005 dollars price projections were converted to nominal dollars using the 2.3 percent general inflation rate discussed in Section 4.0.

To consider the costs associated with emissions of SO_2, NO_x, and CO_2, the emissions rates for every existing generating resource, as well as new capacity additions being considered, were included in the dispatching decisions made by STRATEGIST. Because each generating unit, whether existing or being considered as a supply-side alternative, has a unique emissions profile, the annual emissions allowance costs vary for each unit. Including emissions allowance costs in this manner allows the analysis to take into consideration the "all-in" production costs for each unit, including fuel costs, nonfuel costs, and costs associated with emissions of regulated emissions or potential CO_2 emissions.

19.3 Firm Natural Gas Transportation Costs

As discussed in Section 8.0, the Cane Island site is currently served by both FGT and Gulfstream. FMPA has made various nonbinding requests for incremental firm natural gas transportation associated with proposed expansions of both FGT's and Gulfstream's natural gas transportation systems. For purposes of the analyses presented throughout this Application, it has been assumed that FMPA would secure an additional 20,000 MBtu per day of firm natural gas transportation capacity at a cost of $1.28/MBtu beginning in 2011. FMPA has made no commitments to the amount of incremental firm natural transportation that may be acquired from either FGT or Gulfstream and will continue to evaluate the optimal amount of incremental firm natural gas transportation capacity.

For scenarios in which renewable generation is included as described in Section 20.0, the amount of additional firm natural gas transportation is reduced to 16,000 MBtu per day in proportion to the level of renewable generation.

If additional natural gas transportation is required beyond the existing and additional natural gas transportation capacity, it was assumed to be available at the ITS rate of $0.598/MBtu.

19.4 New Nuclear Generating Units

FMPA is continuing to evaluate the potential to participate in future nuclear generating units that may be constructed in Florida. Four new nuclear generating units have been proposed to the FPSC since October 2007, including FPL's Turkey Point Units 6 and 7 (Docket No. 070650) and Progress Energy Florida's Levy County Units 1 and 2 (Docket No. 080148). The FPSC has issued a need determination for Turkey Point Units 6 and 7 and a need determination proceeding is pending for Levy County Units 1 and 2. For purposes of the analyses presented throughout this Application, it has been assumed that FMPA will receive 28 MW of nuclear capacity from Levy County Unit 1 in June

2016 and 28 MW from Levy Unit 2 in January 2017, and 50 MW of nuclear capacity from Turkey Point Unit 6 in June 2018 and 50 MW of nuclear capacity in June 2020.

19.5 DSM Costs

Since FMPA is continuing to negotiate with both DSM vendors, as discussed in Section 17.0, the costs included in the scenarios that include DSM are based on the DSM vendor with the lowest cost and the greatest amount of DSM. These costs are included in the cumulative present worth costs (CPWC) discussed below, but have not been presented separately because of confidentiality requirements.

19.6 Cumulative Present Worth Cost Analysis

Economic comparisons between competing expansion plans were developed on a CPWC basis. The CPWC calculation accounted for annual system costs (fuel and energy, fixed O&M, nonfuel variable O&M, startup, and levelized capital costs for new unit additions) for each year of the expansion planning period and discounted each back to 2008 using the 5.0 percent present worth discount rate discussed in Section 4.0. In addition, costs for emissions allowances, natural gas transportation, and DSM are included These annual present-worth costs were then totaled over the 2008 through 2027 period to calculate the total CPWC of the expansion plan being considered. Such analysis allows for a comparison of CPWC between various expansion plans, and the plan with the lowest CPWC is considered the least-cost expansion plan for any given scenario considered.

20.0 Economic Evaluation

Detailed economic analyses were performed to evaluate the cost-effectiveness of the addition of Cane Island 4 to help satisfy forecast capacity and energy requirements of FMPA's ARP. Numerous evaluations were conducted in order to consider reference case fuel price and load forecasts as well as sensitivities related to fuel prices, load forecasts, capital costs, and regulation of CO_2 emissions. Additionally, the cost-effectiveness of Cane Island 4 was evaluated under several scenarios involving new renewable energy resources available to FMPA and reductions in coincident peak demand resulting from implementation of a new demand-side management program. The remainder of this section describes each of the scenarios evaluated and presents the corresponding cumulative present worth cost (CPWC) for expansion plans with and without the addition of Cane Island 4 in May 2011.

The economic analyses described herein compare the economics of the least-cost expansion plan including Cane Island 4 in May 2011 versus the economics of the least-cost expansion plan that does not include Cane Island 4 in May 2011. For comparison purposes, the addition of Cane Island 4 in May 2011 was treated as a committed resource, and the optimal expansion model, STRATEGIST, was allowed to select among the supply-side alternatives presented in Section 14.0 to develop the least-cost expansion plan to meet capacity requirements beyond 2011. For cases in which Cane Island 4 was not treated as a committed resource in 2011, STRATEGIST was allowed to select among the supply-side alternatives presented in Section 14.0, including a 1x1 combined cycle identical to Cane Island 4 as early as May 2013.

20.1 Overview of Evaluation Scenarios

The economics of the addition of Cane Island 4 were considered for several cases among four distinct scenarios as outlined below. The results of the economic analyses for each case considered for each scenario are presented in subsequent subsections.

20.1.1 Scenario 1 – Conventional Expansion Scenario

The *Conventional Expansion Scenario* considers the addition of only conventional, (fossil-fueled) generating resources, with the exception of the new nuclear generating resources discussed in Section 19.0. As described previously in this section, the economics of an expansion plan including the addition of Cane Island 4 as a committed resource in May 2011 were evaluated against the economics of an expansion plan that includes a 1x1 combined cycle identical to Cane Island 4 as a generating unit alternative as early as May 2013. The Scenario 1 evaluations were performed for several sensitivity cases described as follows.

20.1.1.1 Reference Case. The *Reference Case* considers the reference case fuel and emission allowance price projections included in Section 7.0 and base case load forecast presented in Section 5.0. The capital cost for Cane Island 4 used in the reference case is presented in Section 9.0, while the capital costs for all other generating unit alternatives are presented in Section 14.0.

20.1.1.2 High Fuel Price Case. The *High Fuel Price Case* considers the high fuel price and corresponding emissions allowance price projections presented in Section 7.0. Capacity requirements used in this case correspond to the base case load forecast presented in Section 5.0. The capital cost for Cane Island 4 used in this case is presented in Section 9.0, while the capital costs for all other generating unit alternatives are presented in Section 14.0.

20.1.1.3 Low Fuel Price Case. The *Low Fuel Price Case* considers the low fuel price and corresponding emissions allowance price projections presented in Section 7.0. Capacity requirements used in this case correspond to the base case load forecast presented in Section 5.0. The capital cost for Cane Island 4 used in this case is presented in Section 9.0, while the capital costs for all other generating unit alternatives are presented in Section 14.0.

20.1.1.4 High Load Case. The *High Load Case* considers the high load forecast presented in Section 5.0. Fuel and emissions allowance price projections used in this case correspond to the reference case projections included in Section 7.0. The capital cost for Cane Island 4 used in this case is presented in Section 9.0, while the capital costs for all other generating unit alternatives are presented in Section 14.0.

20.1.1.5 Low Load Case. The *Low Load Case* considers the low load forecast presented in Section 5.0. Fuel and emissions allowance price projections used in this case correspond to the reference case projections included in Section 7.0. The capital cost for Cane Island 4 used in this case is presented in Section 9.0, while the capital costs for all other generating unit alternatives are presented in Section 14.0.

20.1.1.6 High Capital Case. The *High Capital Cost Case* reflects an increase of 20 percent in the capital cost of Cane Island 4 presented in Section 9.0 as well as the capital costs of all other generating unit alternatives presented in Section 14.0. Fuel and emissions allowance price projections used in this case correspond to the reference case projections included in Section 7.0. The base case load forecast presented in Section 5.0 was used in the high capital cost case.

20.1.1.7 Regulated CO_2 Case. The *Regulated CO_2 Case* considers the fuel and CO_2 emissions allowance price projections corresponding to the EIA's analysis of S.280 as presented in Section 7.0. The CO_2 emissions allowance prices used in this case correspond to the *S.280 Core* analysis. The SO_2 and NO_x emissions allowance prices for this case correspond to the reference case emissions allowance price projections presented in Section 7.0. Capacity requirements used in this case correspond to the base

case load forecast presented in Section 5.0. The capital cost for Cane Island 4 used in this case is presented in Section 9.0, while the capital costs for all other generating unit alternatives are presented in Section 14.0.

20.1.1.8 High Fuel with Regulated CO_2 Case. The *High Fuel with Regulated CO_2 Case* considers the high fuel price projections in Section 7.0 and also considers the CO_2 emissions allowance price projections corresponding to the EIA's analysis of S.280 (also presented in Section 7.0). The CO_2 emissions allowance prices used in this case correspond to the *S.280 Core* analysis. The SO_2 and NO_x emissions allowance prices for this case correspond to the high case emissions allowance price projections presented in Section 7.0. Capacity requirements used in this case correspond to the base case load forecast presented in Section 5.0. The capital cost for Cane Island 4 used in this case is presented in Section 9.0, while the capital costs for all other generating unit alternatives are presented in Section 14.0.

20.1.1.9 High Regulated CO_2 Case. The *High Regulated CO_2 Case* considers CO_2 emissions allowance price projections based on the US Environmental Protection Agency (EPA) analysis of S.2191, the *Climate Security Act of 2007* (now referred to as the *Lieberman-Warner Climate Security Act of 2008*). In March 2008, the EPA published its analysis in response to the request by Senators Lieberman and Warner. The analysis considered several scenarios and used various models to develop numerous forecasts of CO_2 emissions allowance prices[1]. The CO_2 emissions allowance price projections used in the *High Regulated CO_2 Case* correspond to the EPA's *S.2191 Scenario* using the EPA *IGEM* model. This analysis was selected because the resulting CO_2 emissions allowance prices fall within and towards the upper bound of the range of CO_2 allowance price projections developed by the EPA for the various scenarios considered in their analysis of S.2191.

The EPA analysis of S.2191 presented CO_2 emissions allowance price projections in 2005 dollars per ton in 5-year intervals beginning in 2015 and extending through 2050. For analysis purposes, the 2005 dollars per ton price projections were converted to nominal dollars using the 2.3 percent general inflation rate presented in Section 4.0, and linear interpolation was used between the 5-year intervals to develop annual price projections. Forecasts for 2012 through 2014 were developed by determining the average annual escalation rate between 2015 and 2020 and de-escalating the 2015 price projection by the appropriate number of years. The resulting CO_2 emissions allowance price projections for 2012 through 2027 that were used in the *High Regulated CO_2 Case* are presented in Table 20-1. For comparison purposes, Table 20-1 also presents the CO_2 emissions allowance price projections used in the *Regulated CO_2 Case*, which were based on the EIA S.280 Core case projections presented in Section 7.0.

[1] Refer to www.epa.gov/climatechange/economics/economicanalyses.html for the EPA analysis of S.2191.

Table 20-1
Projected CO_2 Emission Allowance Prices
EPA S.2191 Scenario and EIA S.280 Core
(Nominal $/Ton)

Year	EPA S.2191 Scenario	EIA S.280 Core
2012	$40.54	$14.05
2013	$43.54	$15.08
2014	$46.76	$16.08
2015	$50.21	$17.19
2016	$53.93	$18.98
2017	$57.91	$20.97
2018	$62.19	$23.17
2019	$66.79	$25.60
2020	$71.73	$28.28
2021	$77.03	$31.25
2022	$82.72	$34.52
2023	$88.83	$38.14
2024	$95.39	$42.15
2025	$102.43	$46.57
2026	$110.04	$51.44
2027	$118.21	$56.83

The fuel, SO_2, and NO_x emissions allowance prices for this case correspond to the reference case price projections presented in Section 7.0. The use of fuel and emissions allowance price projections developed independently by the EIA and EPA results in a non-integrated forecast. Nevertheless, this scenario provides an indication of the potential effect of a higher-cost CO_2 regualtory regime than that assumed in the Regulated CO_2 Case described above. Capacity requirements used in this case correspond to the base case load forecast presented in Section 5.0. The capital cost for Cane Island 4 used in this case is presented in Section 9.0, while the capital costs for all other generating unit alternatives are presented in Section 14.0.

20.1.2 Scenario 2 – Renewable Expansion Scenario

The *Renewable Expansion Scenario* considers the addition of the new renewable energy resources being considered by FMPA (including biomass and solar PV) as discussed in Section 16.0 in addition to conventional generating resources and the new nuclear generating resources. As with Scenario 1, the *Renewables Expansion Scenario* evaluates the economics of an expansion plan including the addition of Cane Island 4 as a committed resource in May 2011 against the economics of an expansion plan that includes a 1x1 combined cycle identical to Cane Island 4 as a generating unit alternative as early as May 2013. Scenario 2 evaluations were performed for both the *Reference Case* and the *Regulated CO_2 Case*, each of which are described in Section 20.1.1.

The *Renewables Expansion Scenario* assumes the installation of a 58 MW biomass unit with a commercial operation date of January 1, 2012 and the installation of 10 MW solar photovoltaics with commercial operation dates of January 1, 2010. The characteristics of these renewable resources are more fully described in Section 16.0. As discussed in Section 12.0, the 10 MW of solar photovoltaics were assumed to provide 3.3 MW of firm capacity to FMPA's system.

20.1.3 Scenario 3 – DSM Expansion Scenario

The *DSM Expansion Scenario* considers the addition of the new DSM program being evaluated by FMPA as discussed in Section 17.0 in addition to conventional generating resources and the new nuclear generating resources. Existing ARP conservation and DSM programs as discussed in Section 17.1 are embedded in FMPA's base case load forecast. As with Scenario 1, the *DSM Expansion Scenario* evaluates the economics of an expansion plan including the addition of Cane Island 4 as a committed resource in May 2011 against the economics of an expansion plan that includes a 1x1 combined cycle identical to Cane Island 4 as a generating unit alternative as early as May 2013. Scenario 3 evaluations were performed for both the *Reference Case* and the *Regulated CO_2 Case*, each of which are described in Section 20.1.1.

The projected peak demand savings included in the *DSM Expansion Scenario* are presented in Section 17.2.2. For evaluation purposes, the cumulative 44 MW savings is projected to be maintained through the end of the study period. As presented in Section 13.0 FMPA's 2011 summer capacity requirements are 286 MW. With the *DSM Expansion Scenario*, FMPA's 2011 summer capacity requirements are reduced to 260 MW.

20.1.4 Scenario 4 – Renewables and DSM Expansion Scenario

The *Renewables and DSM Expansion Scenario* considers the addition of both the new renewable energy resources and the new DSM program being evaluated (as considered in Scenarios 3 and 4, respectively) in addition to conventional generating resources and the new nuclear generating resources. As with the other scenarios, the *Renewables and DSM Expansion Scenario* evaluates the economics of an expansion plan including the addition of Cane Island 4 as a committed resource in May 2011 against the economics of an expansion plan that includes a 1x1 combined cycle identical to Cane Island 4 as a generating unit alternative as early as May 2013. Scenario 4 evaluations were performed for both the *Reference Case* and the *Regulated CO_2 Case*, each of which are described in Section 20.1.1.

20.2 Results of the Economic Evaluations

CPWC evaluations were performed for the various scenarios and cases within each of the scenarios as discussed previously. The CPWC associated with each of the expansion plans for each of the cases and scenarios are presented in this section.

20.2.1 CPWC Results of Scenario 1 Evaluations

The results of the CPWC evaluations for Scenario 1 are presented in Table 20-2. Analysis of the CPWC associated with each of the cases presented in Table 20-2 indicates that expansion plans including the addition of Cane Island 4 in May 2011 are the most cost-effective expansion plans for all cases considered.

20.2.2 CPWC Results of Scenario 2 Evaluations

The results of the CPWC evaluations for Scenario 2 are presented in Table 20-3. Analysis of the CPWC associated with both of the cases presented in Table 20-3 indicates that expansion plans including the new renewable resources being considered by FMPA as well as the addition of Cane Island 4 in May 2011 are the most cost-effective expansion plans for the two cases considered.

20.2.3 CPWC Results of Scenario 3 Evaluations

The results of the CPWC evaluations for Scenario 3 are presented in Table 20-4. Analysis of the CPWC associated with both of the cases presented in Table 20-4 indicates that expansion plans including the new DSM program being considered by FMPA as well as the addition of Cane Island 4 in May 2011 are the most cost-effective expansion plans for the two cases considered.

Table 20-2
CPWC Summaries for Scenario 1
($000)

Case	CPWC of Expansion Plan Including Cane Island 4 in 2011	CPWC of Expansion Plan Without Cane Island 4 in 2011	CPWC Savings for Expansion Plan with Cane Island 4 in 2011
Reference Case	$6,873,504	$6,909,247	$35,763
High Fuel	$7,521,022	$7,558,293	$37,271
Low Fuel	$6,215,140	$6,243,170	$28,030
High Load	$7,780,149	$7,801,735	$21,586
Low Load	$5,994,755	$6,076,238	$81,483
High Capital Cost	$6,984,600	$7,022,491	$37,891
Regulated CO_2	$7,708,642	$7,714,841	$36,200
High Fuel with Regulated CO_2	$8,556,917	$8,594,522	$37,605
High Regulated CO_2	$9,347,371	$9,387,259	$39,888

Table 20-3
CPWC Summaries for Scenario 2
($000)

Case	CPWC of Expansion Plan Including Cane Island 4 in 2011	CPWC of Expansion Plan Without Cane Island 4 in 2011	CPWC Savings for Expansion Plan with Cane Island 4 in 2011
Reference Case	$7,159,378	$7,193,530	$34,153
Regulated CO_2	$7,953,638	$7,987,190	$33,552

Table 20-4 CPWC Summaries for Scenario 3 ($000)			
Case	CPWC of Expansion Plan Including Cane Island 4 in 2011	CPWC of Expansion Plan Without Cane Island 4 in 2011	CPWC Savings for Expansion Plan with Cane Island 4 in 2011
Reference Case	$6,856,721	$6,909,460	$52,739
Regulated CO_2	$7,692,426	$7,745,238	$52,812

20.2.4 CPWC Results of Scenario 4 Evaluations

The results of the CPWC evaluations for Scenario 4 are presented in Table 20-5. Analysis of the CPWC associated with both of the cases presented in Table 20-5 indicates that expansion plans including the new renewable resources and DSM program being considered by FMPA as well as the addition of Cane Island 4 in May 2011 are the most cost-effective expansion plans for the two cases considered.

Table 20-5 CPWC Summaries for Scenario 4 ($000)			
Case	CPWC of Expansion Plan Including Cane Island 4 in 2011	CPWC of Expansion Plan Without Cane Island 4 in 2011	CPWC Savings for Expansion Plan with Cane Island 4 in 2011
Reference Case	$7,139,004	$7,177,545	$38,341
Regulated CO_2	$7,932,282	$7,972,993	$40,711

20.3 Conclusions

The CPWC results summarized previously in this section demonstrate that the addition of Cane Island 4 in May 2011 is included in the least cost expansion plan for each of the 15 different scenarios and cases evaluated. When combined with both the new renewable resources and the new DSM program being considered by FMPA, Cane Island 4 provides a cost-effective resource addition to the FMPA system to serve the forecast capacity requirements of the ARP.

21.0 Consequences of Delay

As demonstrated by the economic evaluations presented in this Application, the addition of Cane Island Unit 4 in 2011 represents the most cost-effective addition to satisfy FMPA's forecast capacity requirements to reliably serve the ARP members. The consequences of delaying the commercial operation of Cane Island 4 are significant from an economic and reliability standpoint for FMPA. This section describes the negative consequences of delaying the addition of Cane Island Unit 4.

21.1 Economic Consequences

If the commercial operation of Cane Island 4 is delayed, FMPA would be required to replace the capacity and energy that would otherwise be provided by a new, efficient combined cycle generating unit. The economic consequence of delaying the commercial operation of Cane Island Unit 4 for 2 years (from May 2011 until May 2013) is approximately $35.7 million in CPWC, compared to the next most cost effective expansion plan that meets FMPA's 2011 capacity requirements with simple cycle combustion turbines based on *Reference Case* assumptions.

21.2 Reliability Consequences

As shown in Section 13.0, FMPA is projected to require a significant amount of capacity in the summer of 2011 to maintain its reserve margin requirements. If Cane Island Unit 4 is delayed and no additional generating capacity is installed to meet FMPA's forecast capacity requirements by 2011, FMPA's summer reserve margin will fall to approximately -1.3 percent (or 286 MW less than the 18 percent summer reserve criterion) in 2011. The projected capacity deficit in the summer of 2011 is equivalent to nearly all of the capacity that will be provided by Cane Island Unit 4. With a projected negative reserve margin in 2011, FMPA would not be able to serve firm load with resources under FMPA's control. This would increase the probability that FMPA will not be able to provide FMPA's members with capacity to serve their retail customers and will expose FMPA to potentially high purchase power costs.

22.0 Financial Analysis

FMPA's All-Requirements Power Supply Project (ARP) has several available funding sources that may be used to finance the development and construction of Cane Island 4; these include internal funds, pooled loans, and new long-term debt issuances. FMPA is anticipating the need to finance approximately $450 million for construction of Cane Island 4, including direct and indirect engineering, procurement, and construction costs; owner's costs, which include spare parts associated with a long-term service agreement; bond issuance fees; and interest during construction.

FMPA typically finances its capital projects using two funding sources. During preliminary design, engineering, and permitting, FMPA may draw upon its Initial Pooled Loan Project. The Initial Pooled Loan Project is an ongoing FMPA project that provides FMPA and its members loans at very competitive rates. The pooled loans could be expected to finance up to the first $100 million of costs. Once the project is well defined during the engineering, procurement, and construction activities, FMPA could and would ultimately initiate a revenue bond issuance for long-term project funding. For large projects such as a natural gas combined cycle power plant, FMPA would expect to issue either fixed or floating rate revenue bonds or both. The term on the bonds could range between 20 and 30 years. FMPA will likely issue bonds with a term of 20 years to accelerate the amortization of the project. Based on Cane Island 4's favorable economics and the ARP's excellent credit rating, FMPA believes that there will be no problems issuing debt to cover the project cost. FMPA has recently initiated bond offerings with tax-exempt interest rates consistent with or below the rates assumed for the economic analysis.

The ARP has a credit rating of A+ from Fitch and an A1 from Moody's Investors Service. Typically, FMPA purchases bond insurance on its long-term bonds to increase its rating to AAA and Aaa, respectively. As of fiscal year end 2007, FMPA had $1.303 billion in outstanding long-term debt, which includes $637 million in ARP debt.

The actual financing for Cane Island 4 is expected to result in debt service requirements that are less than the assumed debt service presented in the economic parameters in Section 4.0. Although a 5 percent tax exempt rate has been used in recent Need for Power Applications, current and near-term interest rate market conditions are expected to remain favorable to FMPA and tax-exempt financing. The liquidity of the municipal bond market may influence bond rates when the bonds are actually issued.

Appendix A
Request for Power Supply Proposals

FLORIDA MUNICIPAL POWER AGENCY
(All-Requirements Power Supply Project)

Request for
Power Supply Proposals
June 22, 2007
(RFP #0607G)

Pre-bid Meeting: Mandatory Attendance (June 28, 2007)

Proposals are Due August 17, 2007

TABLE OF CONTENTS

1. INTRODUCTION 1
2. FMPA DESCRIPTION 1
3. ALL-REQUIREMENTS POWER SUPPLY PROJECT 2
4. RFP SCHEDULE 3
5. POTENTIAL POWER SUPPLY REQUIREMENTS 3
6. PROPOSALS FOR UNIT CONTINGENT PURCHASES 4
7. SELF-BUILD RESOURCE 4
8. TRANSMISSION ARRANGEMENTS 4
9. NOTICE TO PROPOSERS 5
10. SUBMITTAL OF PROPOSALS 6
11. RIGHT OF REJECTION 7
12. INTERPRETATIONS AND ADDENDA 8
13. ERRORS, MODIFICATIONS OR WITHDRAWAL OF PROPOSAL 8
14. PROPRIETARY CONFIDENTIAL BUSINESS INFORMATION 8
15. PROPOSER QUALIFICATIONS 9
16. PROPOSAL SECURITY AND PERFORMANCE SECURITY 9
17. DEFAULT AND DAMAGES PROVISIONS 10
18. DISQUALIFICATION OF PROPOSALS 10
19. PUBLIC ENTITY CRIMES STATEMENT 10
20. COLLUSION 10
21. EVALUATION PROCESS 11
22. FINAL CONTRACT 15
23. RFP FORMS AND ATTACHMENTS 15

FLORIDA MUNICIPAL POWER AGENCY
Request for Power Supply Proposals

June 22, 2007

1. Introduction

The Florida Municipal Power Agency ("FMPA" or "Agency") is issuing this Request for Proposals ("RFP") as an invitation to qualified companies to submit proposals for the supply of capacity and energy to meet a portion of the projected power requirements of FMPA's All-Requirements Power Supply Project ("ARP"). FMPA is requesting proposals for up to 300 MW of capacity to commence service January 1, 2011 for contract periods of ten (10) years or greater. Acceptable offers from all proposers must total at least 300 MW for FMPA to proceed with purchases under this RFP. Proposals that require FMPA to provide natural gas must identify the natural gas delivery point. Resources providing the proposed capacity, whether an existing plant or proposed new resources, must be in operation at least two (2) months prior to the start date of the proposed power supply arrangement.

FMPA prefers system or unit purchase power proposals that are priced as base load solid fueled resources since FMPA's studies have shown such resources are part of FMPA's least cost plans. 50 MW is the minimum amount for a single offer. Proposals received in response to this RFP will be evaluated in comparison with (i) options that are available to FMPA under existing power supply arrangements and (ii) self-build combined cycle alternatives that are being developed and will serve as a benchmark in the evaluation process. As explained below, resources must be delivered to the Florida Power Corporation d/b/a Progress Energy Florida, Inc. ("PEF") transmission system. Proposals outside of the PEF system must include firm electric transmission to the PEF transmission system for the firm portion of the bid for the life of the proposal, and the firm transmission service must be available starting January 1, 2011.

The deadline for receipt of proposals by FMPA is 3:00 P.M. eastern prevailing time ("EPT") Friday, August 17, 2007. A mandatory Pre-Bid Meeting is planned for June 28, 2007. Qualified companies that wish to attend the Pre-Bid Meeting must register before 5:00 P.M. EPT on June 26, 2007 as described in Section 4.

2. FMPA Description

FMPA was created and exists pursuant to its Interlocal Agreement among its 30 members, which specifies the purposes and authority of FMPA. FMPA was formed under the provisions of Article VII, Section 10, Florida Constitution; Part II, Chapter 361, Florida Statutes, as amended, the "Joint Power Act"; and/or Section 163.01, Florida Statutes, as amended, the "Florida Interlocal Cooperation Act of 1969." The Florida Constitution and the Joint Power Act provide the authority for municipal and other electric utilities to join together for the joint financing, construction, acquiring, managing, operating, utilizing, and owning of electric power plants. The Interlocal Cooperation Act authorizes municipal electric utilities to cooperate with each other on a basis of mutual advantage to provide services and facilities in a manner and in a form of

governmental organization that will accord best with geographic, economic, population, and other factors influencing the needs and development of local communities.

Each municipal electric system that is a signatory to the Interlocal Agreement has the right to appoint one member to FMPA's Board of Directors, the governing body of FMPA. The Board has the responsibility of developing and approving FMPA's budget, approving and financing projects, hiring a General Manager and a General Counsel, and establishing bylaws that govern how FMPA operates and policies that implement such bylaws. At its annual meeting, the Board elects a Chairman, Vice Chairman, Secretary, Treasurer and an Executive Committee. The Executive Committee consists of nine directors elected by the Board plus the current Chairman of the Board, the Vice Chairman, the Secretary, and the Treasurer (13 total). The Executive Committee meets regularly to manage and govern FMPA's day-to-day operations and approve expenditures and contracts. The Executive Committee is also responsible for monitoring budgeted expenditure levels and assuring that authorized work is completed in a timely manner.

3. All-Requirements Power Supply Project

Under the ARP, FMPA currently provides all the power requirements (above certain excluded resources) for fifteen of its members. Initially, the first five members of the ARP were non-generating utilities which had previously received all of their power requirements from full requirements contracts with either Florida Power & Light Company ("FPL") or PEF. The most recent members, Kissimmee Utility Authority and the City of Lake Worth, Florida, joined the ARP in 2002.

Current supply side resources for the ARP are classified into four main areas, the first of which is nuclear capacity. A number of the ARP members own small amounts of capacity in PEF's Crystal River Unit 3. A number of ARP members also participate in the FMPA St. Lucie Project providing them capacity and energy from St. Lucie Unit No. 2. These nuclear resources are referred to as "Excluded Resources." The ARP provides the balance of capacity and energy requirements for the members with participation in these nuclear units. The nuclear units are considered in the capacity planning for the ARP.

The second category of resources is owned generation. This category includes generation that is solely or jointly owned by the ARP as well as ARP member participation in the FMPA Stanton, Tri-City and Stanton II Projects.

The third category of resources is participant-owned generation. Capacity included in this category is generation owned by the ARP Participants either solely or jointly. FMPA purchases this capacity from the ARP Participants and then commits and dispatches the generation as a part of the ARP portfolio of power-supply resources to meet the total requirements of the ARP.

The fourth category of resources is purchased power. This includes power purchased directly by the ARP as well as existing purchase power contracts of individual ARP Participants, which were entered into prior to the ARP Participant joining the ARP.

4. RFP Schedule

FMPA's timetable for this RFP process is shown below. Note that all times shown are based on the eastern prevailing time ("EPT") on the dates indicated; however, the dates shown are only estimates and may be modified at any time by FMPA. Approval for contract execution must come from the Executive Committee of the ARP. Likewise, the selection of the primary supplier must be approved by the Executive Committee of the ARP.

RSVP for Pre-Bid Meeting	June 26, 2007 [5 P.M.]
Pre-Bid Meeting (Mandatory)	June 28, 2007 [10 A.M.]
Notice of Intent to Bid Form Due to FMPA	July 3, 2007 [5 P.M.]
Deadline for Proposer Questions	August 6, 2007 [3 P.M.]
Sealed Proposal(s) Due Date	August 17, 2007 [3 P.M.]
RFP Short List	September 14, 2007
Primary Supplier Selected	October 12, 2007
Contract Developed and Finalized	November 9, 2007
Contract(s) Approved For Execution	December 6, 2007

Pre-Bid Meeting

The FMPA has scheduled a Pre-Bid Meeting for Wednesday, June 28, 2007, 10:00 A.M. EPT, at the offices of the FMPA, 8553 Commodity Circle, Orlando, FL 32819-9002. The purpose of the Pre-Bid Meeting is to provide any required clarifications to this RFP and to provide any additional information deemed necessary in order for Proposers to submit their best proposal. Attendance at the Pre-Bid Meeting is required. Although verbal responses to questions may be provided during the meeting, only written responses will be considered official.

Qualified companies that wish to attend the Pre-Bid Meeting must register with the FMPA by submitting a written list of attendees via e-mail, facsimile or mail to the address provided in Section 10. All registrations must arrive before 5:00 P.M. EPT on June 26, 2007. FMPA is not obligated to consider registrations received after the deadline.

5. Potential Power Supply Requirements

FMPA is accepting a variety of proposal types for capacity and energy in whole megawatt quantities for part or all of the basic capacity requirements along with the flexibility to increase and decrease the purchase amounts. As previously mentioned, FMPA has a variety of power supply options under existing purchase agreements as well as the option to build new generating capacity on sites in Florida. Accordingly, FMPA will consider power supply proposals for contract periods of ten years or greater from (i) existing specified resources, (ii) a portfolio supply of resources with appropriate guarantees; or (iii) a generating facility or facilities to be constructed for a unit power sale. In any event, all proposals must identify the specific resources at specific sites. Proposals based on supply resources located outside the PEF transmission

system must also identify the transmission contracts for the transmission path that will be utilized from the resource(s) to the PEF transmission system interface as more fully described in Section 8.

FMPA prefers a purchase that will be subject to unavailability only due to planned maintenance or forced outages. Financially firm resources will not be acceptable to FMPA. FMPA prefers a 100% dispatchable resource for intermediate and peaking capacity.

6. Proposals for Unit Contingent Purchases

Proposals involving a unit contingent purchase must include all available data including historical (if applicable) and projected equivalent forced outage rate ("EFOR") and equivalent maintenance outage rate ("EMOR") per the North American Electric Reliability Council ("NERC") definitions, maintenance schedules, net capacity, heat rate, fuel type, and other pertinent data for the specific unit(s). All proposals for a capacity/energy sale shall be on a firm first call, non-recallable basis equivalent to native load delivered to the PEF transmission system interface. Details on the information required for each type of proposal are specified in Attachment B.

All proposals shall include scheduling provisions of the sale. For all resources, the schedule should be established no more than one (1) day in advance with the ability to change the schedule within one (1) hour before the schedule commences except under FMPA emergency conditions when changes may be required as soon as physically possible if the resource is available. FMPA is seeking proposals that allow operating flexibility for the resources. Proposals must clearly describe any contractual limitations on energy usage (MWh) by day, month or year. As part of the scheduling provisions, the supplier will be required to fax to FMPA's dispatchers (currently contracted to the Orlando Utilities Commission ("OUC")) on a daily basis a schedule of estimated prices for the energy to be delivered for that day and the next day.

7. Self-Build Resource

The Self-Build Resource for this RFP is a 300 MW F-class 1 x 1 combined cycle unit ("Combined Cycle Unit") at a greenfield or brownfield site, depending on site selection, in Florida with an on line date of January 1, 2011.

8. Transmission Arrangements

Eight (8) of the fifteen (15) ARP Participants are geographically located within FPL's service area, and the other seven (7) ARP Participants are located within PEF's service area. All fifteen (15) ARP Participants are supplied their full-requirements power supply from FMPA and such power is delivered to the ARP Participants over the transmission systems of FPL or PEF, respectively. Network-type transmission arrangements are currently in place that enable FMPA to provide service over both the FPL and PEF systems.

FMPA capacity needs are provided on a system basis; however, the utilization of FMPA's transmission agreements with FPL and PEF must be separately planned. FMPA has determined for this proposal evaluation that all of the proposed capacity and energy must be delivered into the PEF transmission system.

All proposals for potential power supplies, where the supply resources originate from outside the PEF transmission system's balancing authority, should be priced based on the Proposer supplying and paying for firm transmission service from the source(s) of supply to the PEF transmission system balancing authority interface, including the cost of any transmission upgrades required to obtain this firm delivery service. Where resources originate outside the State of Florida, proposals must consider the limits and allocation of interface capacity among the owners of the transmission lines that make up the Florida-Southern interface.

FMPA also requires that the Proposers be responsible for the following costs: (i) all costs associated with interconnecting generating resources to the transmission system; (ii) all transmission upgrades required to facilitate the interconnection of generating resources; and (iii) all transmission upgrades required to facilitate the designation by FMPA of the Proposer's supply resources as a qualified network resource under PEF's Open Access Transmission Tariff ("OATT"). To the extent that transmission credits are provided for upgrades provided by Proposers on the PEF transmission system, these will be credited back to the Proposer.

FMPA may evaluate the potential impact of transmission congestion, redispatch, and losses that may occur between the Proposer's supply resources and FMPA's network loads and may adjust the proposals to take such impacts into consideration. FMPA encourages Proposers to supply any information that the Proposers may have related to the potential impact of transmission congestion, redispatch and losses.

FMPA will give preference to a transmission service arrangement that (i) consists of no more than one intermediate transmission path (between the generating switchyard and the PEF transmission system balancing authority), and (ii) includes the assignment of tariff-provided transmission reassignments/ redirection/resale rights solely to FMPA for the life of the agreement.

9. Notice to Proposers

All Proposers are required to provide written notification of their intent to submit a proposal no later than July 3, 2007 at 5:00 P.M. EPT. A Notice of Intent to Bid Form is included herein as RFP Form 1. On the Notice of Intent to Bid Form, Proposers must indicate the agreement term(s) on which the proposal(s) will be based. All sections of the Notice of Intent to Bid Form must be completed in full, signed by an authorized representative of the Proposer, and submitted to FMPA by facsimile (407-355-5796) or mail (as listed Section 10), and not via the Internet, to the attention of Mr. Bill May.

10. Submittal of Proposals

Sealed proposal packages will be received until August 17, 2007 at 3:00 P.M. EPT ("Proposal Due Date") at the offices of FMPA. **ANY PROPOSAL SUBMITTED VIA THE INTERNET WILL NOT BE ACCEPTED.** Each Proposer is required to submit a completed Proposal Summary (RFP Form 2), a Minimum Requirements Form (Form 3), a Pricing Proposal Form (Form 4) and a Checklist (Form 5) as part of the proposal package. The forms are listed in the last section of this RFP. The proposing company's name and the words "Request for Power Supply Proposals RFP # 0607G" must be clearly identified on the outside of each proposal package. FMPA reserves the right to reject all proposals received after the Proposal Due Date.

One original and three (3) copies of each proposal should be sealed and delivered to the following address:

Mr. Bill May
Manager of Power Supply
Florida Municipal Power Agency
8553 Commodity Circle
Orlando, FL 32819-9002

An electronic copy of the complete Proposal, the pricing terms and all spreadsheets included in the proposal should be submitted in Microsoft Office Professional Edition 2003 or compatible format on CD or DVD to Bill.May@fmpa.com.

The proposals must remain in effect and valid until December 6, 2007 or later if the purchase is to be finalized pending a transmission service request. The proposal packages will be opened after the Proposal Due Date. Each proposal package must be accompanied by a non-refundable Proposal Fee (in the form of a cashier's check made payable to FMPA) in the amount of $2,500 per proposal. If a Proposer submits alternative arrangements, each alternative will be considered a separate proposal. A Proposer submitting multiple proposals is required to supply a $2,500 Proposal Fee for each proposal.

FMPA is willing to consider alternatives that involve a pass through of fuel and variable operation and maintenance costs or a contractually fixed energy charge. For alternatives involving a pass through of fuel costs, a contractually fixed heat rate is preferred. Fuel forecasts for natural gas, coal and No. 2 oil fuels are provided in Attachment A and will be used as the basis for comparison to the Self-Build Resource.

For Proposers that are not fixing the energy charge, if the capacity/energy sale proposal is based on a pass-through fuel cost arrangement, the proposal energy price should be based upon the fuel forecast provided on Attachment A. The Henry Hub gas fuel price forecast and oil fuel price to be used for purposes of FMPA's evaluation have been included. The proposal should include all factors to determine a total price based on the Henry Hub gas price and/or oil price and an explanation of the relationship of the energy rate to fuel prices and explain how gas transportation will be provided. The Proposer should specify the gas delivery point for the

resource, if applicable to the proposal. If any of this information is Proprietary Confidential Business Information, it should be so noted. If the proposal is based on a contractually-fixed total energy cost, the proposal must include all information pertinent to the pricing and its escalation. To the extent the Proposer wants to make an exception to the fuel forecast, such exception must be fully described and supported with appropriate examples. FMPA may or may not reflect these exceptions in the evaluation.

With respect to fixed and variable operation and maintenance expenses ("O&M") and environmental related charges, all charges must be itemized to show different components of costs. All assumptions used in calculating such costs must be clearly stated. Proposers need to list components of costs and other performance parameters so that FMPA can verify that such costs are comparable to the Self-Build Resource. Typical components that may be included are the following:

A. Fixed Operating Expenses (labor, general equipment maintenance, insurance, property taxes, major maintenance, capital expenditures, and administrative costs).

B. Variable O&M (maintenance charge costs related to use, allowances and other consumables).

C. Heat Rate (minimum load level, full load, and intermediate levels at winter, summer and average ambient temperatures.

D. Availability and forced outage rate.

E. Other operating data and restrictions such as ramp rates, start-up costs, minimum load, etc. that may affect operating flexibility and expenses.

FMPA prefers purchases that provide guarantees with respect to various major performance parameters such as output, heat rate, availability, forced outages, fixed and variable operating expenses and fuel prices. Compensation to the seller will be adjusted if guaranteed performance parameters are not achieved. Proposals for new generating unit sales should include prices with and without fuel oil backup facilities necessary to maintain continuous operation at full output for 72 hours.

11. Right of Rejection

This RFP is not an offer establishing any contractual rights. This solicitation is solely an invitation to submit proposals.

FMPA reserves the right to:

- Reject any and all proposals for any reason, or no reason, received in response to this RFP;
- Reject any proposal for failure to extend the validity date if requested;
- Waive any requirement in this RFP;
- Not disclose the reason for rejecting a proposal;
- Negotiate an arrangement for power supply with more than one Proposer at a time;

- Not select the proposal with the lowest apparent price;
- Request clarifications from Proposers at any time; and
- Negotiate with any Proposer that submits a written proposal.

12. Interpretations and Addenda

All questions regarding interpretation of this RFP, technical or otherwise, must be submitted in writing or by the Internet to the following:

By Fax:	Mr. Paul Arsuaga (407) 648-8382
By E-Mail:	parsuaga@RWBeck.com
By Mail or Courier:	Mr. Paul Arsuaga R. W. Beck, Inc. 1000 Legion Place, Suite 1100 Orlando, FL 32801

Only FMPA written responses to Proposers questions will be considered official. A verbal response by FMPA will not be considered an official response. Written responses to questions and requests for interpretations may be provided to all Proposers by posting on the Internet Website. All written questions must be received by FMPA on or before August 6, 2007 at 3:00 P.M. EPT. Inquiries after this date may not receive responses. All addenda issued in connection with this RFP will be placed on the Internet Website (www.fmpa.com), at the time of issue and it shall be the responsibility of those Proposers to regularly check the "Important Updates" page for addenda.

13. Errors, Modifications or Withdrawal of Proposal

Each Proposer should carefully review the information provided in the RFP prior to submitting a response. The RFP contains instructions which must be followed by all Proposers. Modifications (other than minor additions and/or corrections) to proposals already received by FMPA will only be accepted prior to the Proposal Due Date. Proposals may be withdrawn by giving written notice (no Internet notices) to FMPA prior to the Proposal Due Date. In such cases, a full refund of the Proposal Fee will be provided by FMPA. Proposals withdrawn after the Proposal Due Date may result in forfeiture of the proposal fees.

14. Proprietary Confidential Business Information

FMPA is a governmental entity subject to the Florida Public Records Law (Chapter 119, Florida Statutes). Some, or all, of the materials or information provided by Proposer to FMPA will be considered a "public record" which FMPA, by law, is obligated to disclose upon request of any person for inspection and copying, unless the public record or the information is otherwise specifically exempt by statute. Should a Proposer provide any materials which it believes, in good faith, contain information which would be exempt from disclosure or copying under Florida law, the Proposer shall indicate that belief by typing or printing, in bold letters, the

phrase "PROPRIETARY CONFIDENTIAL BUSINESS INFORMATION" both on the initial page and on the face of each affected page of such material and shall submit both a complete and a redacted version of such material. Should any person request to examine or copy any material so designated, only the redacted version of the affected material or page(s) thereof will be produced. If the person requests to examine or copy the complete version of the affected material or page(s), FMPA shall notify the affected Proposer of that request, and the Proposer, within thirty-six (36) hours of receiving such notification, shall either permit or refuse to permit such disclosure or copying. If a Proposer refuses to permit disclosure or copying, Proposer agrees to, and shall, hold harmless, indemnify and defend FMPA for all expenses, costs, damages, and penalties of any kind whatsoever which may be incurred by FMPA, or assessed or awarded against FMPA, in regard to FMPA's refusal to permit disclosure or copying of such material. If litigation is filed in relation to such request and a Proposer is not initially named as a party, the Proposer shall promptly seek to intervene as a defendant in such litigation to defend its claim regarding the confidentiality of such material. This provision shall take precedence over any provisions or conditions of the Proposer's proposal and any provision of any other document relating to the disclosure of materials or information considered by the provider to be confidential or proprietary and shall constitute FMPA's sole obligation with regard to maintaining confidentiality of material or documents, of any kind, or any other information provided by the Proposer or its Affiliates or Sub Contractors.

15. Proposer Qualifications

FMPA will accept proposals from any electric utility, independent power producer ("IPP"), qualifying facility ("QF"), exempt wholesale generator, or non-utility generator, or electric power marketer who has received certification as such by the FERC. Proposers unfamiliar to FMPA may be required to provide proof of experience.

Proposers offering capacity/energy sales from an existing unit(s) must own and operate the unit, plant or system capacity or must have the unit(s), plant or system capacity under contract. FMPA may require proof of such contracts as well as proof of contracts for sales from a portfolio of resources. Any contracts submitted with the proposal may have the price and other sensitive information deleted before submittal to FMPA. For proposals involving a new project, Proposer should supply information on the status of the project including site development, permitting, purchase of land options, etc.

Electric power plant operators must provide proof of operating experience as requested in Attachment B. Respondents are encouraged to provide the following information with their proposals: most recent audited financial statement; Form 10K of parent company, where appropriate; most recent Dunn & Bradstreet report; description of pending litigation; summary of project experience; and most recent annual report.

16. Proposal Security and Performance Security

FMPA requires that the Proposer provide a letter of commitment from a financial institution with a credit rating of at least A- by S&P, A3 by Moody's or A- from Fitch to be a guarantor for a Proposal Security to be established by the Proposer equal to five dollars ($5) per kilowatt (kW)

of the capacity offered in the proposal within ten (10) days of being notified that the proposal is on the short-list of proposals. The Proposal Security will be forfeited if the Proposer changes its proposal in a material adverse manner after being short-listed or fails to establish a contract Performance Security prior to contract execution with the Proposer. The Proposal Security is to remain in effect until the later of the date to which proposals remain valid or to such time that FMPA executes a contract with the Proposer providing for the Performance Security or FMPA executes an agreement with a different Proposer or combination of Proposers to meet its requirements, or decides to reject all proposals. The letter of commitment will state further that the financial institution will commit to be a guarantor for a Performance Security established by the Proposer when the contract is executed that will minimize FMPA's exposure to direct and consequential damage due to failure of the Proposer to fulfill the terms and conditions of the contract awarded. The amount of the Performance Security will be a percentage of the revenues over the remaining life of the contract.

17. Default and Damages Provisions

FMPA will negotiate the conditions of default and damages with the successful Proposer(s). Proposers should include suggested default and damage provisions in their proposals.

18. Disqualification of Proposals

Proposal(s) may be disqualified at any point if bribery, conflict of interest, or interference in the evaluation process is/are suspected or determined, at FMPA's sole discretion.

19. Public Entity Crimes Statement

Pursuant to Section 287.133(2)(a), FLORIDA STATUTES, all bidders should be aware of the following:

> "A person or affiliate who has been placed on the convicted vendor list following a conviction for a public entity crime may not submit a bid on a contract to provide any goods or services to a public entity, may not submit a bid on a contract with a public entity for the construction or repair of a public building or public work, may not submit bids on leases of real property to a public entity, may not be awarded or perform work as a contractor, supplier, subcontractor, or consultant under a contract with any public entity, and may not transact business with any public entity in excess of the threshold amount provided in Section 287.017, for CATEGORY TWO for a period of 36 months from the date of being placed on the convicted vendor list."

20. Collusion

By offering a submission pursuant to this Invitation to Bid, the Proposer certifies the Proposer has not divulged, discussed, or compared his bid with other Proposers and has not colluded with any other bidder or parties to this bid whatsoever. Also, the Proposer certifies, and in the case of a joint bid, each party thereto certifies, as to his own organization, that in connection with this bid:

(1) Any prices and/or cost data submitted have been arrived at independently, without consultation, communication, or agreement for the purpose of restricting competition, as to any matter relating to such prices and or cost data, with any other Proposer or with any competitor.

(2) Any prices and/or cost data quoted for this bid have not knowingly been disclosed by the Proposer and will not knowingly be disclosed by the Proposer prior to the scheduled opening directly or indirectly to any other Proposer or to any competitor.

(3) No attempt has been made or will be made by the Proposer to induce any other person or firm to submit or not to submit a bid for the purpose of restricting competition.

(4) The only person or persons interested in this bid, principal or principals is/are named therein and that no person other than therein mentioned has any interest in this bid or in the contract to be entered into and;

(5) No person or agency has been employed or retained to solicit or secure this contract upon an agreement or understanding for a commission, percentage, brokerage, or contingent fee accepting bona fide employees or established commercial agencies maintained by the Proposer for the purpose of doing business.

21. Evaluation Process

In the initial stages of the evaluation process, cost estimates to be developed concurrently for the Self-Build Resource will be used as a benchmark for screening alternatives. Repricing of proposals is not anticipated. Therefore, Proposers should provide their lowest cost offer on the Proposal Due Date.

The proposal evaluation process will be performed on a bid and negotiate basis. Information provided from each qualified Proposer by the Proposal Due Date will be used to develop a short-list of proposals from which selection(s) could be made for direct negotiations. No additional Proposer data will be considered after the Proposal Due Date, except for clarifications requested by FMPA and possible transmission system study results obtained from FPL, PEF, and/or any other affected transmission provider. FMPA will evaluate the proposals in terms of price and non-price factors. The first stage of the evaluation process for qualified Proposers may consist of a check of each proposal against the minimum requirements of the RFP. After the minimum requirements screening, initial price screening of proposals may be accomplished by comparing such proposals using a capacity factor analysis. Those proposals may then be screened by comparison with options that are available to FMPA under existing power purchase arrangements and with options delaying the Self-Build Resource. Screenings may be performed on a present value busbar cost basis. Price and non-price evaluations may be conducted next. During the evaluation process, FMPA may develop scenarios which include combining proposals from one or more Proposers.

Price and non-price evaluations may include a preliminary analysis of transmission limitations to verify that Proposers have properly addressed the limitations and included appropriate costs. Once a short-list of Proposers is developed, FMPA may inform PEF of the potential short-listed Proposers as possible power suppliers to FMPA in order to secure transmission services.

Additional system studies, which incorporate proposed power supply resources, may be used to verify the sufficiency of the transmission systems and their interfaces and determine if additional transmission system facilities may be required. Should FMPA or others determine, based on their studies, that additional transmission facilities or costs are required to accommodate particular proposed power supplies, each affected Proposer may then be contacted by FMPA with this information to explore possible alternatives, if any, to address the problem. To the extent that these problems cannot be resolved, the proposal may be rejected or the evaluation may reflect this cost uncertainty. Proposers will remain responsible for all transmission upgrades required to facilitate the designation by FMPA of the Proposer's supply resources as a qualified network resource under the PEF OATT whether or not such costs can be estimated. Proposals may be eliminated at this point based solely on a determination that additional transmission facilities are required and that there is insufficient time to complete the installation of such facilities. Any costs associated with such transmission system studies performed by FMPA, PEF, or FPL will be the responsibility of FMPA.

Proposals that remain on the short-list may be analyzed on an overall system cost basis. From this analysis, the Proposer(s) may be selected for participation in negotiations. The Proposer(s) selected will be notified for commencement of negotiations. Selection and rejection of proposals and notification of Proposers at all stages will remain entirely within FMPA's discretion. FMPA intends to notify Proposers not selected under this solicitation within a reasonable amount of time.

FMPA may evaluate the potential impact of transmission congestion and losses that may occur between the Proposer's supply resources and FMPA's network loads and may adjust the proposals to take such impacts into consideration. FMPA encourages Proposers to supply any information that the Proposers may have related to the potential impact of transmission congestion, redispatch and losses.

Minimum Requirements for All Proposals

Each proposal must satisfy certain minimum requirements before it will receive any further evaluation. The Proposer must demonstrate in its submittal that the following minimum requirements have been met:

1. For a generating unit power sale, FMPA's rights must be equal to or superior to any other party's rights to such unit(s) output (i.e. as long as the unit(s) from which the capacity is purchased is available, FMPA has the right to the output of the unit(s) for the duration of the contract).

2. All proposals for peaking capacity must commence on January 1, 2011.

3. All proposals must have contract periods of not less than 10 years.

4. All proposals must remain in effect until December 6, 2007, or later if the purchase is to be finalized pending a transmission service request.

5. The capacity amount offered to FMPA shall be not less than 50 MW or greater than 300 MW. Acceptable offers from all Proposers must total at least 300 MW for FMPA to proceed with purchases under this RFP. Proposals that require FMPA to provide natural gas must identify the natural gas delivery point.

6. All generating units providing the proposed capacity must be in commercial operation at least two (2) months prior to the required delivery commencement date of the term of the proposed power supply.

7. Proposals must identify and include the location of each capacity resource and name the originating control area. Resources must be delivered to the PEF transmission system. Proposers proposing power supply from a resource(s) located outside of the PEF balancing authority must also identify the firm transmission contract path from the power supply(s) to the PEF transmission system.

8. The Proposer must commit in the proposal that all emissions allowance requirements will be satisfied and must include costs for emission allowances in the proposal.

9. The Proposer must declare ownership or contractual status of a unit, or plant as described in Section 15.

10. The Proposer must complete the appropriate RFP Forms 1 through 5 and provide all appropriate information requested in Attachment B. All forms requiring a signature must be signed by a duly authorized official of the Proposer.

11. The Proposer must commit in the proposal to provide an adequate Proposal Security prior to entering short-list negotiations and an adequate Performance Security upon execution of a contract in accordance with Section 16.

12. Each proposal must clearly describe any contractual limits on energy utilization or physical limitations on the operation of the resource as described in Attachment B.

13. Each proposal must include scheduling provisions for the sale.

14. Each proposal must contain the appropriate Proposal Fee in accordance with Section 10.

15. Proposals for new construction projects must not be contingent upon participation by other third parties to support the project.

16. Proposers that propose to develop a power generating project to provide power to FMPA must have developed, and have had in operation for a minimum of one (1) year, at least one (1) currently operating power supply project that is similar to, or larger in size than, the project being proposed. Proposers offering to provide FMPA with power from an existing generating resource must have successfully provided similar levels of services to at least one (1) electric utility for a minimum of one (1) year.

Price Criteria

FMPA will evaluate the proposal(s) as an alternative to the Self-Build Resource or increasing the amount of purchases under the existing ARP arrangements. The net present value of the revenue requirements to FMPA over the contract period for each proposal will be compared with: (a) the net present value of revenue requirements over the contract period for the most attractive arrangement to increase purchases under the existing ARP contracts; and/or (b) the net present value of revenue requirements over the contract period for the Self-Build Resource. Scores will then be applied to each proposal to reflect the projected cost differential between the proposal and the benchmark option.

Non-Price Criteria

Each proposal may be evaluated based on a list of non-price criteria, which FMPA has or will develop. A score will be assigned to each criterion based on the extent to which the proposal satisfies FMPA's preferences. The non-price score and price related score for each proposal may be used to determine the ranking of proposals.

The proposals may be evaluated in accordance with the following non-price criteria:

Components of Power Cost -	To evaluate risk, FMPA prefers proposers that identify the true fixed and variable costs for the resources providing the power (e.g., the Proposer should identify the amount of fixed cost in the capacity charge and the amount of variable costs [fuel, variable operation and maintenance expenses, etc.] in the energy charge).
Contract Flexibility -	FMPA prefers proposals with reasonable notice provisions that give FMPA the sole right to increase or decrease the contract term and the amount of purchases.
Dispatchability -	FMPA prefers provisions for capacity that would permit FMPA flexibility to schedule and dispatch the resources to optimize the economics of its resource mix and to take advantage of economy transactions.
Firm Supply -	Proposals will be evaluated on the availability of generating resources and penalties for nonperformance.
Experience	FMPA prefers Proposers with experience providing services similar to that requested.
Transmission -	FMPA prefers generating resources that minimize the number of intermediate transmission systems. Power must be delivered to the PEF transmission system.
Technology -	Proposals utilizing commercially proven technologies are preferable.

22. Final Contract

Any final contract(s) that results from the proposal evaluation and negotiation processes will be submitted to the Board of Directors and/or Executive Committee of FMPA for approval. The tentative date for approval of contract(s) is shown in Section 4, RFP Schedule.

23. RFP Forms and Attachments

Form 1	-	Notice of Intent to Bid Form
Form 2	-	Proposal Summary Form
Form 3	-	Minimum Requirements Form
Form 4	-	Pricing Proposal Form
Form 5	-	Checklist
Attachment A	-	Natural Gas and Oil Price Forecast
Attachment B	-	Required Data to be Submitted with Proposals

RFP Form 1

FLORIDA MUNICIPAL POWER AGENCY
REQUEST FOR POWER SUPPLY PROPOSALS

Notice of Intent to Bid Form

Due: July 3, 2007 (5:00 PM EPT)

Date: _____

Project Proposer Name: _____
Title: _____
Company Name: _____
Address: _____
_____
Telephone: _____
Fax: _____
E-Mail: _____
Project Name: _____
Project Location: _____
Agreement Term: _____
Generation Technology: _____
Primary Fuel: _____
Specific Entity to Contract With FMPA: _____

Respondent Classification: (Utility, Qualified Facility, Exempt Wholesale Generator, Power Marketer, etc.)

Respondent Qualifications: Describe similar projects developed by Proposer, noting project capacity, location, contract commencement date, contract term, etc.
(Attach additional sheets as needed)

_____
_____
_____
_____
_____
_____
_____
_____
_____

Proposer's Signature: _____
(Duly Authorized)

RFP Form 2

FLORIDA MUNICIPAL POWER AGENCY
REQUEST FOR POWER SUPPLY PROPOSALS

Proposal Summary Form

1. Company/Proposer _____
2. Name of Contact _____
3. Mailing Address _____
4. Telephone _____
   Fax _____
   E-Mail _____
5. Proposed Contract Start Date _____
6. Proposed Contract End Date _____

7. Proposed Contract Capacity Listing by Resource

Unit Name and Number	Summer MW Rating	Winter MW Rating	Fuel Type	Location	Proposed Capacity Delivered [1] (MW)	Transmission Path
				Total Capacity (MW)		

[1] *Capacity delivered into the PEF system.*

8. Proposer certifies that they have reviewed all Addenda including Addenda ___ through ___.

9. Certification: Proposer hereby certifies that all of the statements and representations made in this proposal package, including attached documents, are true to the best of the Proposer's knowledge and belief. Proposer agrees to be bound by its representations and the terms and conditions of the Request for Proposals:

Signed: _____

(Typed): _____

Title: _____
(Duly Authorized)

Date: _____

FLORIDA MUNICIPAL POWER AGENCY
REQUEST FOR POWER SUPPLY PROPOSALS

Minimum Requirements Form

In submitting this form, we agree to the items below and/or have provided documents to attest to the information provided as requested below.

Duly Authorized Signature: _____ _____
(Date)

If the proposer is an entity proposing a capacity sale from existing resources, the proposer must provide sufficient documentation to demonstrate that over time the source utility or entity will have sufficient capacity to sell to FMPA as well as to serve its own load, if applicable, and other commitments.

All proposers must demonstrate the following by attaching appropriate information to this form:

1. For a generating unit power sale, FMPA's rights must be equal to or superior to any other party's rights to such unit(s) output (i.e. as long as the unit(s) from which the capacity is purchased is available, FMPA has the right to the output of the unit(s) for the duration of the contract).

2. All proposals for peaking capacity must commence on January 1, 2011.

3. All proposals must have contract periods of not less than 10 years.

4. All proposals must remain in effect until December 6, 2007, or later if the purchase is to be finalized pending a transmission service request.

5. The capacity amount offered to FMPA shall be not less than 50 MW or greater than 300 MW. Acceptable offers from all Proposers must total at least 300 MW for FMPA to proceed with purchases under this RFP. Proposals that require FMPA to provide natural gas must identify the natural gas delivery point..

FLORIDA MUNICIPAL POWER AGENCY
REQUEST FOR POWER SUPPLY PROPOSALS

Minimum Requirements Form

(Continued)

6. All generating units providing the proposed capacity must be in commercial operation at least two (2) months prior to the required delivery commencement date of the term of the proposed power supply.

7. Proposals must identify and include the location of each capacity resource and name the originating control area. Resources must be delivered to the PEF transmission system. Proposers proposing power supply from a resource(s) located outside of the PEF balancing authority must also identify the firm transmission contract path from the power supply(s) to the PEF transmission system.

8. The Proposer must commit in the proposal that all emissions allowance requirements will be satisfied and must include costs for emission allowances in the proposal.

9. The Proposer must declare ownership or contractual status of a unit, or plant as described in Section 15.

10. The Proposer must complete the appropriate RFP Forms 1 through 5 and provide all appropriate information requested in Attachment B. All forms requiring a signature must be signed by a duly authorized official of the Proposer.

11. The Proposer must commit in the proposal to provide an adequate Proposal Security prior to entering short-list negotiations and an adequate Performance Security upon execution of a contract in accordance with Section 16.

12. Each proposal must clearly describe any contractual limits on energy utilization or physical limitations on the operation of the resource as described in Attachment B.

13. Each proposal must include scheduling provisions for the sale.

14. Each proposal must contain the appropriate Proposal Fee in accordance with Section 10.

15. Proposals for new construction projects must not be contingent upon participation by other third parties to support the project.

16. Proposers that propose to develop a power generating project to provide power to FMPA must have developed, and have had in operation for a minimum of one (1) year, at least one (1) currently operating power supply project that is similar to, or larger in size than, the project being proposed. Proposers offering to provide FMPA with power from an existing generating resource must have successfully provided similar levels of services to at least one (1) electric utility for a minimum of one (1) year.

FLORIDA MUNICIPAL POWER AGENCY
REQUEST FOR POWER SUPPLY PROPOSALS

Capacity Pricing Proposal Form

The Proposer must itemize the capacity pricing as required into various price components (i.e., capital, fixed O&M, etc.) Columns A through E may be used for variations in capacity price by time of day, day of week, month, or season for example. These components should be described on the next page. The Proposer is not required to use all columns provided.

	Delivered Capacity Rate							
Period 12 Mo. Ended April 30,	**A** $/kW-mo.	**B** $/kW-mo.	**C** $/kW-mo.	**D** $/kW-mo.	**E** $/kW-mo.	**Total A-E** $/kW-mo.	**Capacity kW**	**Total $000**
2011								
2012								
2013								
2014								
2015								
2016								
2017								
2018								
2019								
2020								
2021								
2022								
2023								
2024								
2025								
2026								
2027								
2028								
2029								
2030								

FLORIDA MUNICIPAL POWER AGENCY
REQUEST FOR POWER SUPPLY PROPOSALS

Capacity Pricing Proposal Form

Describe the components of and the methodology for determining the capacity rates.

FLORIDA MUNICIPAL POWER AGENCY
REQUEST FOR POWER SUPPLY PROPOSALS

Energy Pricing Proposal Form

The Proposer must itemize the energy pricing as required into various price components (i.e., fuel, variable O&M, etc.) The columns F through I are provided to allow the Proposer to list separate price components and may be used for variations in energy price by time of day, day of week, month, or season for example. These components should be described on the next page. The Proposer is not required to use all columns provided.

Delivered Energy Rate									
Period 12 Mo. Ended April 30,	Fuel Cost $/mmBtu	Heat Rate mmBtu/ MWh	F $/MWh	G $/MWh	H $/MWh	I $/MWh	Total F-I $/MWh	Projected Energy MWh	Total $000
2011									
2012									
2013									
2014									
2015									
2016									
2017									
2018									
2019									
2020									
2021									
2022									
2023									
2024									
2025									
2026									
2027									
2028									
2029									
2030									

FLORIDA MUNICIPAL POWER AGENCY
REQUEST FOR POWER SUPPLY PROPOSALS

Energy Pricing Proposal Form

Describe the components of and the methodology for determining the energy rates.

FLORIDA MUNICIPAL POWER AGENCY
REQUEST FOR POWER SUPPLY PROPOSALS

Checklist

All RFP Forms checked below have been included as part of the response package *.

RFP Form 2 - Proposal Summary Form _____

RFP Form 3 - Minimum Requirements Form _____

RFP Form 4 - Pricing Proposal Form _____

Signature of Proposer: _____

Name of Project: _____

(*) *RFP Form 1 is the Notice of Intent to Bid Form which is sent to FMPA prior to, and separately from, the proposal package.*

ATTACHMENT A

RFP Fuel Forecast
(Generic Florida Location)

Year	Natural Gas Price Forecast (Commodity Only) (Nominal $/mmBtu)	No 2 Oil Price Forecast (Delivered) (Nominal $/mmBtu)	Coal Price Forecast (Delivered) (Nominal $/mmBtu)
2010	$7.08	$10.33	$2.71
2011	$6.60	$10.45	$2.64
2012	$6.38	$10.51	$2.52
2013	$6.44	$10.43	$2.36
2014	$6.40	$10.55	$2.42
2015	$6.32	$10.81	$2.42
2016	$6.32	$11.30	$2.48
2017	$6.50	$11.67	$2.55
2018	$6.80	$12.19	$2.62
2019	$7.11	$12.59	$2.68
2020	$7.12	$13.08	$2.66
2021	$7.35	$13.51	$2.62
2022	$7.73	$14.06	$2.68
2023	$8.19	$14.55	$2.91
2024	$8.68	$15.05	$3.11
2025	$9.19	$15.57	$3.24
2026	$9.73	$16.11	$3.37
2027	$10.30	$16.66	$3.51
2028	$10.91	$17.24	$3.65
2029	$11.56	$17.83	$3.80
2030	$12.24	$18.45	$3.96

ATTACHMENT B

Required Supply Proposal Data

The following is required for all supply proposals as is applicable. The required data should be provided in sections numbered in accordance with the specific items detailed below. Each section should begin on a new page. Information provided, but not in the requested format, may be disregarded and the proposal rejected for incompleteness. General information (e.g., promotional material, 'boiler plate', etc.) may be provided with the proposal, but only the formatted information will be considered in the event of conflicting data. Any proposal that lacks requested information may be deemed incomplete and may be rejected in FMPA's sole discretion. FMPA may request additional data or clarifying information from respondents.

Information requirements are specified for two types of proposals: (i) Section B-1 for those involving sales from specific generating unit(s) (a "Generating Unit Sale"); or (ii) Section B-2 a firm sale from a utility system (a "System Sale"). All proposals must include the information requirements in Section B-3.

B-1 Generating Unit(s) Power Sale

B-1.1 Identity of Proposer Contact

Provide the full name, business address, telephone, E-Mail address if available, and facsimile number of contact person from whom additional information can be requested.

B-1.2 General Description of Supply Proposals

(a) Provide a general overall executive summary of the supply proposals. The description must include identification of each major component of involved electric generating unit, including unit type, unit manufacturer, date of manufacture, manufacturer's nameplate capacity rating, any reratings that have occurred since date of manufacture, location of resources, primary and secondary fuel type, term of contract, sites where similar units have been installed for commercial operation, and other relevant information.

(b) Fully describe the scheduling requirements and dependable capacity of the proposed resource.

B-1.3 Location of Generating Unit(s)

Identify the geographic location of the project and indicate whether or not such area is an attainment or a non-attainment air quality area. If no specific location has been identified, so state. Provide a segment of a USGS map showing geographical location of each generating unit with interconnections and transmission lines indicated.

B-1.4 Capacity and Expected Energy Production

(a) Specify the amount of firm capacity offered. Please specify net electrical output at eighty-seven degrees Fahrenheit (87°F) and seventy-four percent (74%) relative humidity available for four (4) continuous hours at the most efficient level of operation. Please further specify a heat rate curve reflecting net output capacity and net heat rate including the average heat rate at the minimum operating capacity and an incremental heat rate curve between minimum and maximum operating capacity.

(b) Indicate the expected total net kilowatt-hours to be delivered to the PEF transmission system under the contract, by hour, for a typical day's operation. Take into account step-up transformer losses, transmission losses to the interface, capacity degradation, and auxiliary loads. Identify limiting conditions (if any).

(c) Show separately, the amount of capacity provided for reserves, or firming service. FMPA may wish to purchase unreserved capacity and reserves, or firming service, separately.

B-1.5 Schedule

Specify the time frame when capacity is available. If capacity is provided by a new generating facility, include a schedule for environmental permitting, design, procurement, construction and commissioning of the project, as applicable.

B-1.6 Proposed Agreement Term

(a) Specify proposed contract term.

(b) Specify any and all proposed provisions for renewal or extension, and cancellation notice, identifying any and all proposed conditions for the above to occur, including whether such events are proposed to be mutually or unilaterally determined.

B-1.7 Scheduling Requirements

(a) Specify: (1) annual availability in hours; (2) annual planned maintenance in hours; (3) expected annual full forced outages in hours; (4) expected annual partial forced outages in hours; (5) frequency, in months, and duration, in days, of periodic (less frequently than annually) major overhauls and/or recommended hours of operation between major overhauls.

(b) Specify the expected calendar months for annual planned maintenance to occur.

(c) Please specify any other scheduling requirements.

B-1.8 History of Existing Facilities

(a) If the proposed facility is an existing generator(s), provide a narrative describing the project's operating history. Include construction start date, test operation start date, commercial operation date, monthly capacity factors, non-fuel operations and maintenance expenses, and net heat rates by month, for at least three (3) years or since commercial operation date if later. Also include major equipment additions and enhancements.

(b) If the proposed facility is comprised of an existing generator(s), provide a narrative describing the project's maintenance history, including: (i) monthly and annual scheduled outages, (ii) number and duration of forced outages, (iii) forced and planned outage rates, (iv) dates and causes of all major equipment breakdowns by year, etc., and (v) all known equipment deficiencies.

B-1.9 FMPA Rights

Verify that no party has superior rights to FMPA.

B-1.10 Fuel Information

Fully describe the fuel source(s) for any proposed generating facility, and any fuel supply contracts, including price and escalation provisions, interruptibility, obligation to deliver, penalties for non-delivery, and dispatchability. Specify project fuel type(s), and associated fuel supply information to the extent known, including number and delivery capability of suppliers. The Proposer should specify the gas delivery point for the resource and describe gas transportation arrangements if the Proposer is supplying this. If the fuel source requires any emission allowances, the Proposer shall specify if entitlements are now held for the required allowances. If entitlements to required allowances are not held, the Proposer shall identify the source from which allowances will be obtained, and any separate charge proposed to be assessed. Proposals for new generating unit sales should include prices with and without fuel oil backup facilities necessary to maintain continuous operation for 72 hours at full output.

B-1.11 Operations and Maintenance Expense

Fully describe and itemize all components of operations and maintenance expenses that are included in the proposal and state all assumptions used in the calculation of such expenses. At a minimum, pricing must include the following components to the extent applicable:

(a) Fixed operation and maintenance costs including labor, general equipment maintenance, insurance, property taxes, major maintenance, capital expenditures, and administrative costs.

(b) Variable operation and maintenance costs including limestone, ash and scrubber sludge disposal, ammonia, catalyst replacement, SO_2, NO_X, and mercury allowances, CO_2 taxes (if applicable), water related costs, and other consumables.

(c) If the fuel source requires any emission allowances, the Proposer shall specify if entitlements are now held for the required allowances. If entitlements to required allowances are not held, the Proposer shall identify the source from which allowances will be obtained, and any separate charge proposed to be assessed.

B-2 System Sale

B-2.1 Identity of Proposer Contract

Provide the full name, business address, telephone, and facsimile number of contract person from whom additional information can be requested.

B-2.2 General Description of Supply Proposals

(a) Provide a general overall summary of the supply proposals. The description must include identification of each resource in the electric system from which sale is being made (the "System").

(b) Describe the amount of capacity to be provided, the amount of total resources, and projected loads (including the proposal sale) on the System for each year of the proposed contract. Describe any scheduling requirement of the resource.

B-2.3 Location of Generating Facilities

Identify the geographic location of the generating resources on the System and the transmission system that interconnects these resources. Identify the transmission path and intervening transmission systems required to deliver the power to the PEF transmission system.

B-2.4 Capacity and Expected Energy Production

(a) Specify the amount of delivered capacity and maximum energy offered on typical days, months and years, taking into account seasonality of supply (if any) and transmission losses.

(b) Please indicate the firmness of the sale (i.e. verify that no other parties will have superior rights).

B-2.5 Proposed Agreement Term

(a) Specify proposed contract term.

(b) Specify any and all proposed provisions for renewal or extension, and cancellation notice, identifying any and all proposed conditions for the above to occur, including whether such events are proposed to be mutually or unilaterally determined.

B-2.6 Scheduling Requirement

Indicate all scheduling requirements applicable to the proposed system sale.

B-3 General Information

B-3.1 Financial Information

(a) Identify any and all Proposer affiliates.

(b) Provide audited financial statements, if available, or other financial statements for the last three (3) years. Such information must be provided for all entities, including affiliates involved in the transaction. For investor owned utilities, this would include as a minimum, FERC Form 1's and SEC 10K forms. Proposers should also provide where appropriate, the most recent Dunn and Bradstreet report, a description of pending litigation and the most recent annual report.

B-3.2 Pricing Information

(a) Specify on the RFP Form 4 - Proposal Pricing form, all proposed payment components and proposed incentive amounts, if any, and the conditions which engage such provisions. FMPA requires that proposals clearly distinguish energy and capacity pricing components. For example fixed components may include fixed O&M capital, etc. Energy components may include fuel, variable O&M, etc.

(b) Specify annual payment stream components, whether explicitly specified or driven by escalation factors. If price escalation factors are proposed, please identify what attribute the proposed factor is to represent (e.g., general inflation, general economic growth, etc.), proposed index or other source data to define the escalator (e.g., CPI, change in GDP, etc.), and Proposer's current projection of designated escalator for each applicable time period.

B-3.3 Proposed Financial Security Arrangements

(a) Please describe the Proposal Security and the Performance Security.

(b) Please provide name and credit rating of financial institution providing letter of commitment.

B-3.4 Transmission

Delivery of power must be into the PEF transmission system. Proposers are required to provide the following supporting data relating to transmission availability:

(a) A detailed description of the proposed wheeling and interconnection arrangements to deliver power into the PEF transmission system, including, but not limited to, contract path and estimated cost of such wheeling services.

(b) Interconnection points at which resources used for sale are interconnected with the transmission provider in whose balancing authority the resource is located.

(c) A description of any required new interconnection facilities and estimated costs and cost responsibility for such facilities.

(d) A description of upgrades on the PEF, FPL and on third party transmission systems that may be required to accommodate the project and an estimate of costs that is included in the pricing.

(e) Backup information that would verify the reasonableness of assumptions and cost data associated with transmission service required for delivery of the proposed capacity and energy from the source(s) of supply to the point of delivery and detailed analyses which will demonstrate that the Proposer's proposal can be qualified as a "network resource" under the PEF transmission tariff. Such analyses must show all assumptions, including, among other things, contract paths, contracting parties, interface capability, intervening parties, and transfer capabilities. FMPA may verify the transmission studies provided by the Proposer by performing its own load flow studies. Therefore, proposers are encouraged to submit a hard copy of the transmission analysis results plus the load flow cases in raw data ASCII IBM compatible format (i.e., PTI's PSS/E, GE's PSLF, IEEE common), along with all assumptions used in creating each case and any special instructions for reading the data.

B-3.5 Summary of Proposer's Qualification

(a) Provide a description of the Proposer's qualifications and experience applicable to the developing, designing, financing, constructing, operating and maintaining of the proposed project.

(b) Identify and describe existing generation facilities currently in commercial service on which proposer has contracted, including (i) the name, address, telephone number, and specific contact of the owner of such facilities; (ii) a description of the facility and its location; (iii) the Proposer's scope of work relating to the project; and (iv) total contract value and duration.

B-3.6 Additional Information

Please provide any additional information that Proposer believers will assist FMPA in an accurate and fair evaluation of the proposed project.

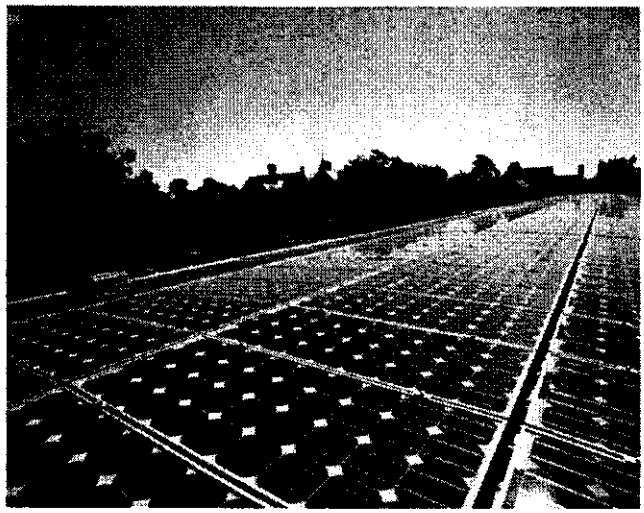
B-3.7 Guaranty for Firm Power

Describe the formula or mechanism whereby the power and energy will be compensated or replaced, and/or the capacity or energy payments reduced when or if the project fails to provide firm power when required by FMPA.

Appendix B
Request for Proposals Renewable Capacity and Energy

Florida Municipal Power Agency
(All-Requirements Power Supply Project)

Request for Proposals
Renewable Capacity and Energy
June 29, 2007
(RFP # 0607R)



Pre-Bid Meeting July 11, 2007

Proposals are Due August 29, 2007

Florida Municipal Power Agency

REQUEST FOR PROPOSALS, RENEWABLE CAPACITY AND ENERGY

1. INTRODUCTION 1
2. FMPA DESCRIPTION 1
3. ALL-REQUIREMENTS POWER SUPPLY PROJECT 2
4. RFP SCHEDULE 3
5. POTENTIAL POWER SUPPLY REQUIREMENTS 3
6. TRANSMISSION ARRANGEMENTS 4
7. NOTICE OF INTENT TO BID 5
8. PRE-BID MEETING 5
9. SUBMITTAL OF PROPOSALS 6
10. RIGHT OF REJECTION 7
11. INTERPRETATIONS AND ADDENDA 7
12. ERRORS, MODIFICATION OR WITHDRAWAL OF PROPOSAL 8
13. PROPRIETARY CONFIDENTIAL BUSINESS INFORMATION 8
14. PROPOSER QUALIFICATIONS 9
15. PROPOSAL SECURITY AND PERFORMANCE SECURITY 9
16. DEFAULT AND DAMAGES PROVISIONS 10
17. DISQUALIFICATION OF PROPOSALS 10
18. PUBLIC ENTITY CRIMES STATEMENT 10
19. COLLUSION 10
20. EVALUATION PROCESS 11
    PRICE CRITERIA 14
    NON-PRICE CRITERIA 14
21. RFP FORMS 15

FLORIDA MUNICIPAL POWER AGENCY
Request for Proposals, Renewable Capacity and Energy

June 29, 2007

1. Introduction

The Florida Municipal Power Agency ("FMPA" or "Agency") is issuing this Request for Proposals ("RFP") as an invitation to qualified companies to submit proposals for the supply of renewable capacity and energy or energy only to meet a portion of the projected power requirements of FMPA's All-Requirements Power Supply Project ("ARP"). FMPA is seeking proposals from qualified and eligible bidders with prior operating experience with the proposed resource type that the Proposer is offering. Proposals must be at least 1 MW. The minimum term will be five (5) years. Although delivery of firm, reliable capacity and energy is required to begin no later than January 1, 2011, FMPA will consider projects that can begin delivery of capacity and energy or energy only earlier than this date. Resources providing the proposed firm capacity and energy, whether an existing plant or proposed new resources, must be in operation at least two (2) months prior to the start date of the proposed power supply.

For purposes of this RFP, renewable resources will include a facility that is or will be interconnected for synchronous operation and delivery of electricity to an electric utility where the sole source of fuel used for the production of energy for sale to FMPA is from one or more of the following sources.

- hydrogen produced from sources other than fossil fuels
- biomass (including waste to energy and landfill gas)
- solar energy
- geothermal energy
- wind energy
- ocean energy
- hydroelectric power
- waste heat from a commercial or industrial process
- Any other technologies utilizing fuel/energy sources deemed by FMPA to be renewable in nature

A Pre-Bid meeting will be held at the office of FMPA on July 11, 2007 and Proposals are due by 3 P.M. EPT on August 29, 2007.

2. FMPA Description

The Florida Municipal Power Agency was created and exists pursuant to its Interlocal Agreement among its 30 members, which specifies the purposes and authority of FMPA. FMPA was formed under the provisions of Article VII, Section 10, Florida Constitution; Part II, Chapter 361, Florida Statutes, as amended, the "Joint Power Act"; and/or Section

Copyright 2007, R. W. Beck, Inc.
All Rights Reserved

163.01, Florida Statutes, as amended, the "Florida Interlocal Cooperation Act of 1969." The Florida Constitution and the Joint Power Act provide the authority for municipal and other electric utilities to join together for the joint financing, construction, acquiring, managing, operating, utilizing, and owning of electric power plants. The Interlocal Cooperation Act authorizes municipal electric utilities to cooperate with each other on a basis of mutual advantage to provide services and facilities in a manner and in a form of governmental organization that will accord best with geographic, economic, population, and other factors influencing the needs and development of local communities.

Each municipal electric system that is a signatory to the Interlocal Agreement has the right to appoint one member to FMPA's Board of Directors, the governing body of FMPA. The Board has the responsibility of developing and approving FMPA's budget, approving and financing projects, hiring a General Manager and a General Counsel, and establishing bylaws that govern how FMPA operates and policies that implement such bylaws. At its annual meeting, the Board elects a Chairman, Vice Chairman, Secretary, Treasurer and an Executive Committee. The Executive Committee consists of nine directors plus the current Chairman of the Board, the Vice Chairman, the Secretary, and the Treasurer (13 total). The Executive Committee meets regularly to manage and govern FMPA's day-to-day operations and approve expenditures and contracts. The Executive Committee is also responsible for monitoring budgeted expenditure levels and assuring that authorized work is completed in a timely manner.

3. All-Requirements Power Supply Project

Under the ARP, FMPA currently provides all the power requirements (above certain excluded resources) for fifteen of its members. Initially, the first five members of the ARP were non-generating utilities which had previously received all of their power requirements from full requirements contracts with either FPL or PEF. The most recent members, Kissimmee Utility Authority and the City of Lake Worth, Florida, joined the ARP in 2002.

Current supply side resources for the ARP are classified into four main areas, the first of which is nuclear capacity. A number of the ARP members own small amounts of capacity in PEF's Crystal River Unit 3. A number of ARP members also participate in the St. Lucie Project providing them capacity and energy from St. Lucie Unit No. 2. These nuclear resources are referred to as "Excluded Resources." The ARP provides the balance of capacity and energy requirements for the members with participation in these nuclear units. The nuclear units are considered in the capacity planning for the ARP.

The second category of resources is owned generation. This category includes generation that is solely or jointly owned by the ARP as well as ARP member participation in the FMPA Stanton, Tri-City, and Stanton II Projects.

The third category of resources is participant-owned generation. Capacity included in this category is generation owned by the ARP Participants either solely or jointly. FMPA purchases this capacity from the ARP Participants and then commits and dispatches the generation as a part of the ARP portfolio of power-supply resources to meet the total

Copyright 2007, R. W. Beck, Inc.
All Rights Reserved

requirements of the ARP.

The fourth category of resources is purchased power. This includes power purchased directly by the ARP as well as existing purchase power contracts of individual ARP Participants, which were entered into prior to the ARP Participant joining the ARP.

4. RFP Schedule

The FMPA timetable for this RFP process is shown below. The dates and times are presently only estimates and may be changed at any time at the sole discretion of FMPA. All times in this RFP are shown in Eastern Prevailing Time ("EPT"). Approval for contract execution must come from the Risk Oversight Committee ("ROC") and the Executive Committee ("EC") of the ARP.

Public Notice of RFP	-	June 29, 2007
RFP Available for Distribution	-	June 29, 2007
Pre-Bid Meeting	-	July 11, 2007 [10 A.M.]
Notice of Intent to Propose Due to FMPA	-	July 16, 2007 [3 P.M.]
Deadline for Proposer Questions	-	August 15, 2007 [3 P.M.]
Sealed Proposal(s) Due Date	-	August 29, 2007 [3 P.M.]
RFP Short List *	-	October 5, 2007
Presentation of Results to the ROC		December 6, 2007
Primary Suppliers referred to EC for approval	-	January 24, 2008
Contract Developed and Finalized	-	February 29, 2008
Contract(s) Approved for Execution	-	March 28, 2008

* Depends on number of bidders and alternatives received.

5. Potential Power Supply Requirements

FMPA is requesting renewable energy proposals in part to meet its future load and capacity requirements as summarized in the table below. Proposals for renewable capacity and energy or energy-only resources are requested, which together with its other resources, FMPA could use to meet its future demand, net energy requirements, and reliability requirements. Firm energy resources will be given a preference; however, non-firm resources will be considered at the discretion of FMPA. FMPA is seeking proposals from Proposers to provide a highly reliable resource of capacity and energy or energy only from an identifiable generating resource(s) deliverable to the PEF or FPL transmission systems.

Proposers are required to explain in detail specifically how they will assure FMPA of their ability to reliably provide wholesale power to FMPA. FMPA reserves the right to determine the amount of dependable capacity associated with each proposal for calculating the capability of the proposed resource(s) to meet its required capacity reserve

Copyright 2007, R. W. Beck, Inc.
All Rights Reserved

requirements. Bids that permit FMPA to satisfy its capacity and energy requirements through the use of multiple resources and a diversity of technologies and fuel types may be preferred for reliability purposes.

The Proposer must agree to allow FMPA the right to retain all renewable energy credits or attributes (for example, "REC" or "green tags" credits, but not including any federal or state income tax credits) for power delivered to FMPA under the proposal. Facilities must be located in the State of Florida. Proposers may be required to certify power to be delivered per future State of Florida renewable energy standards.

The Proposer must take into consideration FMPA minimum load conditions and "must run" or "must take" resource obligations. FMPA is looking for the Proposer to develop, finance, build, own and operate the proposed project. FMPA is open to consider any pricing arrangement including all-in energy pricing or multi-part rates that include separate demand and energy price components. The preferred pricing should be fixed rates for the term offered. The details and presentation format of the data required to be submitted as a part of proposals in response to this RFP are specified in Attachment A.

Proposals may require Performance Security described in Section 15 to protect FMPA's members from potential failure to perform. FMPA reserves all rights to limit the amount of firm capacity from a single proposal or from proposals in aggregate to protect FMPA's members from potential failure to perform.

6. Transmission Arrangements

Eight (8) of the fifteen (15) ARP Participants are geographically located within FPL's service area, and the other seven (7) ARP Participants are located within PEF's service area. All fifteen (15) ARP Participants are supplied their full-requirements power supply from FMPA and such power is delivered to the ARP Participants over the transmission systems of FPL or PEF, respectively. Network-type transmission arrangements are currently in place that enable FMPA to provide service over both FPL's and PEF's systems.

FMPA capacity needs are provided on a system basis; however, the utilization of FMPA's transmission agreements with FPL and PEF must be separately planned. FMPA has determined for this proposal evaluation that all of the proposed capacity and energy must be delivered into the FPL or PEF transmission systems ("Network").

All proposals for firm power supplies, where the supply resources originate from outside the Network's balancing authorities, should be priced based on the Proposer supplying and paying for firm transmission service from the source(s) of supply to the Network balancing authority interface, including the cost of any transmission upgrades required to obtain this firm delivery service. Firm transmission may not be required for as-available energy-only resources.

FMPA also requires that the Proposers be responsible for the following costs: (i) all costs associated with interconnecting generating resources to the transmission system; (ii) all

Copyright 2007, R. W. Beck, Inc.
All Rights Reserved

transmission upgrades required to facilitate the interconnection of generating resources; and (iii) for firm resources, all transmission upgrades required to facilitate the designation by FMPA of the Proposer's supply resources as a qualified network resource under FPL's and/or PEF's Open Access Transmission Tariff ("OATT"). To the extent that transmission credits are provided for upgrades provided by Proposers on the FPL and/or PEF system, these will be credited back to the Proposer.

FMPA may evaluate the potential impact of transmission congestion, redispatch, and losses that may occur between the Proposer's supply resources and FMPA's network loads and may adjust the proposals to take such impacts into consideration. FMPA encourages Proposers to supply any information that the Proposers have related to the potential impact of transmission congestion, redispatch and losses.

FMPA will give preference to a transmission service arrangement that (i) consists of no more than one intermediate transmission path (between the generating switchyard and the Network balancing authority), and (ii) includes the assignment of tariff-provided transmission reassignments/redirection/resale rights solely to FMPA for the life of the agreement.

7. Notice of Intent to Bid

All Proposers are required to provide written notification of their intent to submit a proposal no later than July 16, 2007 at 3:00 P.M. EPT. A Notice of Intent to Bid Form is included herein as RFP Form 1. On the Notice of Intent to Bid Form, Proposers must indicate the agreement term(s) on which the proposal(s) will be based. All sections of the Notice of Intent to Bid Form must be completed in full, signed by an authorized representative of the Proposer, and submitted to FMPA by facsimile or mail (not via the Internet) to the attention of Mr. Bill May.

8. Pre-Bid Meeting

FMPA has scheduled a Pre-Bid Meeting for Wednesday, July 11, 2007, 10:00 A.M. EPT, at the offices of FMPA, 8553 Commodity Circle, Orlando, FL 32819-9002. The purpose of the Pre-Bid Meeting is to provide any required clarifications to this RFP and to provide any additional information deemed necessary in order for Proposers to submit their best proposal. Attendance at the Pre-Bid Meeting is optional. Although verbal responses to questions may be provided during the meeting, only written responses will be considered official.

Qualified companies that wish to attend the Pre-Bid Meeting should register with FMPA by submitting a written list of attendees via e-mail, facsimile or mail to the address provided in Section 9 before 5:00 P.M. EPT on July 10, 2007.

Copyright 2007, R. W. Beck, Inc.
All Rights Reserved

9. Submittal of Proposals

Sealed proposal packages will be received until August 29, 2007 at 3:00 P.M. EPT ("Proposal Due Date") at the offices of FMPA. **ANY PROPOSAL SUBMITTED VIA THE INTERNET WILL NOT BE ACCEPTED.** Each Proposer is required to submit a completed Proposal Summary (RFP Form 2), a Minimum Requirements Form (Form 3), a Pricing Proposal Form (Form 4) and a Checklist (Form 5) as part of the proposal package. The forms are listed in Section 21 of this RFP. The proposing company's name and the words "Request for Proposals Renewable Capacity and Energy RFP #0607R" must be clearly identified on the outside of each proposal package. FMPA reserves the right to reject all proposals received after the Proposal Due Date.

One original and three (3) copies of each proposal should be sealed and delivered to the following address:

Mr. Bill May
Manager of Power Supply
Florida Municipal Power Agency
8553 Commodity Circle
Orlando, FL 32819-9002

An electronic copy of the complete Proposal, the pricing terms and all spreadsheets included in the proposal should be submitted in Microsoft Office Professional Edition 2003 or compatible format on CD or DVD.

The proposals must remain in effect and valid until March 28, 2008 or later if the purchase is to be finalized pending a transmission service request. The proposal packages will be opened after the Proposal Due Date. Each proposal package must be accompanied by a non-refundable Proposal Fee (in the form of a cashier's check made payable to FMPA) in the amount of $500 per proposal. If a Proposer submits alternative arrangements, each alternative will be considered a separate proposal. A Proposer submitting multiple proposals is required to supply a $500 Proposal Fee for each proposal.

FMPA is willing to consider alternatives that involve a pass through of fuel and variable operation and maintenance costs or a contractually fixed energy charge. For alternatives involving a pass through of fuel costs, a contractually fixed heat rate is preferred. If the proposal is based on a contractually-fixed total energy cost, the proposal must include all information pertinent to the pricing and its escalation.

With respect to fixed and variable operation and maintenance expenses ("O&M"), all charges must be itemized to show different components of costs. All assumptions used in calculating such costs must be clearly stated. Proposers need to list components of costs and other performance parameters. Typical components that may be included are the following:

Copyright 2007, R. W. Beck, Inc.
All Rights Reserved

- Fixed Operating Expenses (labor, general equipment maintenance, insurance, property taxes, major maintenance, capital expenditures, administrative costs).
- Variable O&M (maintenance charge costs related to use, allowances and other consumables).
- For resources that involve fuel-to-power conversion, heat rate (minimum load level, full load, and intermediate levels at winter, summer and average ambient temperatures) and heat content (Btu/lb) of fuel source.
- Availability and forced outage rate.
- Other operating data/restrictions such as ramp rates, start-up costs, minimum load, etc. that may affect operating flexibility and expenses.

FMPA prefers purchases that provide guarantees with respect to various major performance parameters such as output, heat rate, availability, forced outages, fixed and variable operating expenses and fuel prices. Compensation to the Seller will be adjusted if guaranteed performance parameters are not achieved. FMPA prefers purchases that are dispatchable by FMPA.

10. Right of Rejection

This RFP is not an offer establishing any contractual rights. This solicitation is solely an invitation to submit proposals.

FMPA reserves the right to:

- Reject any and all proposals for any reason, or no reason, received in response to this RFP;
- Reject any proposal for failure to extend the validity date if requested;
- Waive any requirement in this RFP;
- Not disclose the reason for rejecting a proposal;
- Negotiate an arrangement for power supply with more than one Proposer at a time;
- Not select the proposal with the lowest apparent price;
- Request clarifications from Proposers at any time; and
- Negotiate with any Proposer that submits a written proposal.

11. Interpretations and Addenda

All questions regarding interpretation of this RFP, technical or otherwise, must be submitted in writing or by e-mail to the following:

Copyright 2007, R. W. Beck, Inc.
All Rights Reserved

Mr. Paul Arsuaga
1000 Legion Place, Suite 1100
Orlando, FL 32803
Phone: (407) 648-3502
Fax: (407) 648-8382
E-Mail: parsuaga@rwbeck.com

Only FMPA written responses to Proposers questions will be considered official. A verbal response by FMPA will not be considered an official response. Written responses to questions and requests for interpretations may be provided to all Proposers by posting on the Internet Website. All written questions must be received by FMPA on or before August 15, 2007 at 3:00 P.M. EPT. Inquiries after this date may not receive responses. All addenda issued in connection with this RFP will be placed on the "Important Updates" page on the Internet Website (www.fmpa.com), at the time of issue and it shall be the responsibility of those Proposers to regularly check the "Important Updates" page for addenda.

12. Errors, Modification or Withdrawal of Proposal

Each Proposer should carefully review the information provided in the RFP prior to submitting a response. The RFP contains instructions which must be followed by all Proposers. Modifications to proposals already received by FMPA will only be accepted prior to the Proposal Due Date. Proposals may be withdrawn by giving written notice (no Internet notices) to FMPA prior to the Proposal Due Date. In such cases, a full refund of the Proposal Fee will be provided by FMPA.

13. Proprietary Confidential Business Information

FMPA is a governmental entity subject to the Florida Public Records Law (Chapter 119, Florida Statutes). Some, or all, of the materials or information provided by the Proposer to FMPA will be considered a "public record" which FMPA, by law, is obligated to disclose upon request of any person for inspection and copying, unless the public record or the information is otherwise specifically exempt by statute. Should a Proposer provide any materials which it believes, in good faith, contain information which would be exempt from disclosure or copying under Florida law, the Proposer shall indicate that belief by typing or printing, in bold letters, the phrase "PROPRIETARY CONFIDENTIAL BUSINESS INFORMATION" both on the initial page and on the face of each affected page of such material and shall submit both a complete and a redacted version of such material. Should any person request to examine or copy any material so designated, only the redacted version of the affected material or page(s) thereof will be produced. If the person requests to examine or copy the complete version of the affected material or page(s), FMPA shall notify the affected the Proposer of that request, and the Proposer, within thirty-six (36) hours of receiving such notification, shall either permit or refuse to permit such disclosure or copying. If the Proposer refuses to permit disclosure or copying, the Proposer agrees to, and shall, hold harmless, indemnify and defend FMPA for all expenses, costs, damages,

Copyright 2007, R. W. Beck, Inc.
All Rights Reserved

and penalties of any kind whatsoever which may be incurred by FMPA, or assessed or awarded against FMPA, in regard to the Proposer's refusal to permit disclosure or copying of such material. If litigation is filed in relation to such request and the Proposer is not initially named as a party, the Proposer shall promptly seek to intervene as a defendant in such litigation to defend its claim regarding the confidentiality of such material. This provision shall take precedence over any provisions or conditions of the Proposer's proposal and any provision of any other document relating to the disclosure of materials or information considered by the provider to be confidential or proprietary and shall constitute FMPA's sole obligation with regard to maintaining confidentiality of material or documents, of any kind, or any other information provided by the Proposer or its Affiliates or Sub Contractors.

14. Proposer Qualifications

FMPA will accept proposals from any electric utility, independent power producer ("IPP"), qualifying facility ("QF"), exempt wholesale generator, or non-utility generator, or electric power marketer who has received certification as such by the FERC. Proposers unfamiliar to FMPA may be required to provide proof of experience.

Proposers offering capacity/energy sales from an existing unit(s) must own and operate the unit, plant or system capacity or must have the unit(s), plant or system capacity under contract. FMPA may require proof of such contracts as well as proof of contracts for sales from a portfolio of resources. Any contracts submitted with the proposal may have the price and other sensitive information deleted before submittal to FMPA. For proposals involving a new project, Proposer should supply information on the status of the project including site development, permitting, purchase of land options, etc.

Electric power plant operators must provide proof of operating experience as requested in Attachment A. Respondents are encouraged to provide the following information with their proposals: most recent audited financial statement; Form 10K of parent company, where appropriate; most recent Dunn & Bradstreet report; description of pending litigation; summary of project experience; and most recent annual report.

15. Proposal Security and Performance Security

FMPA requires that the Proposer provide a letter of commitment from a financial institution with a credit rating of at least A- by S&P, A3 by Moody's or A- from Fitch to be a guarantor for Proposal Security to be established by the Proposer equal to five dollars ($5) per kilowatt (kW) of the capacity offered in the proposal within ten (10) days of being notified that the proposal is on the short-list of proposals. The Proposal Security will be forfeited if the Proposer changes its proposal in a material adverse manner after being short-listed or fails to establish contract Performance Security prior to contract execution with the Proposer. The Proposal Security is to remain in effect until the later of the date to which proposals remain valid or to such time that FMPA executes a contract with the Proposer providing for the Performance Security or FMPA executes an agreement with a different

Copyright 2007, R. W. Beck, Inc.
All Rights Reserved

Proposer or combination of Proposers to meet its requirements, or decides to reject all proposals. The letter of commitment will state further that the financial institution will commit to be a guarantor for a Performance Security established by the Proposer when the contract is executed that will minimize FMPA's exposure to direct and consequential damage due to failure of the Proposer to fulfill the terms and conditions of the contract awarded. The amount of the Performance Security will be a percentage of the revenues over the remaining life of the contract.

16. Default and Damages Provisions

FMPA will negotiate the conditions of default and damages with the successful Proposer(s). Proposers should include suggested default and damage provisions in their proposals.

17. Disqualification of Proposals

Proposal(s) may be disqualified at any point if bribery, conflict of interest, or interference in the evaluation process is/are suspected or determined, at FMPA's sole discretion.

18. Public Entity Crimes Statement

Pursuant to Section 287.133(2)(a), FLORIDA STATUTES, all bidders should be aware of the following:

> "A person or affiliate who has been placed on the convicted vendor list following a conviction for a public entity crime may not submit a bid on a contract to provide any goods or services to a public entity, may not submit a bid on a contract with a public entity for the construction or repair of a public building or public work, may not submit bids on leases of real property to a public entity, may not be awarded or perform work as a contractor, supplier, subcontractor, or consultant under a contract with any public entity, and may not transact business with any public entity in excess of the threshold amount provided in Section 287.017, for CATEGORY TWO for a period of 36 months from the date of being placed on the convicted vendor list."

19. Collusion

By offering a submission pursuant to this Invitation to Bid, the Proposer certifies the Proposer has not divulged, discussed, or compared his bid with other Proposers and has not colluded with any other bidder or parties to this bid whatsoever. Also, the Proposer certifies, and in the case of a joint bid, each party thereto certifies, as to his own organization, that in connection with this bid:

(1) Any prices and/or cost data submitted have been arrived at independently, without consultation, communication, or agreement for the purpose of restricting

Copyright 2007, R. W. Beck, Inc.
All Rights Reserved

competition, as to any matter relating to such prices and or cost data, with any other Proposer or with any competitor.

(2) Any prices and/or cost data quoted for this bid have not knowingly been disclosed by the Proposer and will not knowingly be disclosed by the Proposer prior to the scheduled opening directly or indirectly to any other Proposer or to any competitor.

(3) No attempt has been made or will be made by the Proposer to induce any other person or firm to submit or not to submit a bid for the purpose of restricting competition.

(4) The only person or persons interested in this bid, principal or principals is/are named therein and that no person other than therein mentioned has any interest in this bid or in the contract to be entered into and;

(5) No person or agency has been employed or retained to solicit or secure this contract upon an agreement or understanding for a commission, percentage, brokerage, or contingent fee accepting bona fide employees or established commercial agencies maintained by the Proposer for the purpose of doing business.

20. Evaluation Process

Repricing of proposals is not anticipated; therefore, Proposers should provide their lowest cost offer on the Proposal Due Date. The proposal evaluation process will be performed on a bid and negotiate basis. Information provided from each qualified Proposer by the Proposal Due Date will be used to develop a short-list of proposals from which selection(s) could be made for direct negotiations. No additional Proposer data will be considered after the Proposal Due Date, except for clarifications requested by FMPA and possible transmission system study results obtained from FMPA, FPL, PEF, and/or any other affected transmission provider. FMPA will evaluate the proposals in terms of price and non-price factors. The first stage of the evaluation process for qualified Proposers will consist of a check of each proposal against the minimum requirements of the RFP. After the minimum requirements screening, initial price screening of proposals for short- or medium-term arrangements may be accomplished by comparing such proposals using a capacity factor analysis. Those proposals may be ranked on economics and risks with other renewable proposals and may then be compared with sources of power that are available to FMPA. Screenings may be performed on a nominal and present value busbar cost basis. Price and non-price evaluations may be conducted next. During the evaluation process, FMPA may develop scenarios that include combining proposals from one or more Proposers. One or more renewable proposals may be selected based on recommendations from the Risk Oversight Committee.

Price and non-price evaluations may include a preliminary analysis of transmission limitations to verify that Proposers have properly addressed the limitations and included appropriate costs. Once a short-list of Proposers is developed, FMPA may inform PEF or FPL, as appropriate, of the potential short-listed Proposers as possible power suppliers to FMPA in order to secure FMPA network transmission services.

Copyright 2007, R. W. Beck, Inc.
All Rights Reserved

Additional system studies, which incorporate proposed power supply resources, may be used to verify the sufficiency of the transmission systems and their interfaces and determine if additional transmission system facilities may be required. Should FMPA or others determine, based on their studies, that additional transmission facilities or costs are required to accommodate particular proposed power supplies, each affected Proposer will then be contacted by FMPA with this information to explore possible alternatives, if any, to address the problem. To the extent that these problems cannot be resolved, the proposal may be rejected or the evaluation will reflect this cost uncertainty. Proposers will remain responsible for all transmission upgrades required to facilitate the designation by FMPA of the Proposer's supply resources as a qualified network resource under the FPL and/or PEF OATT whether or not such costs can be estimated. Proposals may be eliminated at this point based solely on a determination that additional transmission facilities are required and that there is insufficient time to complete the installation of such facilities. Any costs associated with such transmission system studies performed by FMPA, PEF, or FPL will be the responsibility of FMPA.

Proposals that remain on the short-list will be analyzed on an overall system cost basis. From this analysis, the Proposer(s) will be selected for participation in negotiations. The Proposer(s) selected will be notified for commencement of negotiations. Selection and rejection of proposals and notification of Proposers at all stages will remain entirely within FMPA's discretion. FMPA intends to notify Proposers not selected under this solicitation within a reasonable amount of time. Selected proposals will be presented to the Executive Committee for approval.

FMPA may evaluate the potential impact of transmission congestion and losses that may occur between the Proposer's supply resources and FMPA's network loads and resources and may adjust the proposals to take such impacts into consideration. FMPA encourages Proposers to supply any information that the Proposers may have related to the potential impact of transmission congestion, redispatch and losses.

Minimum Requirements for All Proposals

Each proposal must satisfy certain minimum requirements before it will receive any further evaluation. The Proposer must demonstrate in its submittal that the following minimum requirements have been met:

1. The proposal contains the appropriate Proposal Fee in accordance with Section 9.
2. The proposal is for at least 1 MW and begins delivery no later than January 1, 2011.
3. The proposal shall remain valid to the later of March 28, 2008, or the date of receipt of all regulatory approvals required for the proposal and any related transmission service.
4. Proposals for firm capacity and energy are priced inclusive of the Proposer supplying and arranging for all third party transmission into the FMPA system (qualified network resource under FPL's and/or PEF's Open Access Transmission

Copyright 2007, R. W. Beck, Inc.
All Rights Reserved

Tariff) and located in the State of Florida. The Proposer has identified the means of assuring firm delivery of capacity resources.

5. The Proposer has agreed to pay for all necessary transmission upgrades to provide for interconnection and delivery service to the FMPA system.

6. For proposals involving a sale to more than one utility from the same resource(s) identified as supplying the sale to the FMPA, FMPA's rights to the output shall be equal to, or greater than, the rights of all other customers served by the resource(s).

7. The Proposer ensures that all emissions allowance requirements will be satisfied and that any associated costs shall be borne by the Proposer.

8. The Proposer demonstrates ownership or contractual rights to the generating system capacity which is identified as supplying the sale.

9. Resources providing the proposed firm capacity and energy, whether an existing plant or proposed new resources, must be in operation at least two (2) months prior to the start date of the proposed power supply.

10. The Proposer has completed the appropriate RFP Forms 1 through 4. All forms requiring a signature must be signed by a duly authorized official representing the Proposer.

11. The Proposer has provided a Letter of Commitment to establish an acceptable Proposal Security as solely determined by FMPA within ten (10) days of being notified that his proposal is on the short-list of proposals.

12. Proposers shall have successfully provided under contract to at least one electric utility for a minimum period of one year, similar services to the services they are providing to FMPA and have included information in the proposal to demonstrate this experience.

13. The Proposer agrees to assist FMPA to obtain final contract approval from their respective governing bodies in public sessions, where required.

14. The Proposer agrees to provide a letter of commitment from a financial institution with a credit rating of at least A- by S&P, A3 by Moody's or A- from Fitch to be a guarantor for a Proposal Security to be established by the Proposer equal to five dollars ($5) per kilowatt (kW) of the capacity offered in the proposal within ten (10) days of being notified that the proposal is on the short-list of proposals.

15. Pricing information must be provided by Proposers in sufficient detail for FMPA to fully analyze each proposal.

16. The Proposer must provide agreements and disclose sufficient information relating to the provision of fuels, critical spare parts, technical service and support, and maintenance plans to permit FMPA to evaluate the proposals for reliability.

17. If the Proposer is proposing an energy-only, must take, non-dispatchable, or any other arrangement that would require FMPA to take energy from the Proposer at

Copyright 2007, R. W. Beck, Inc.
All Rights Reserved

levels that may not be scheduled by FMPA, then the proposal must contain a projected schedule of energy to be provided under the proposal. Such schedules must contain sufficient detail to permit an analysis of hourly energy patterns by day and month over the proposed contract period.

Price Criteria

FMPA will evaluate the power supply proposals against each other and other power supply alternatives available to FMPA to determine the lowest priced proposals. Impacts that a power supply proposal will have on the operation of the existing and planned resources of FMPA will also be considered. The costs may be compared on an annual basis as well as cumulatively over multiple time periods.

Non-Price Criteria

Each proposal may be compared to the preferences of FMPA under various selected criteria and a score will be assigned based on the ability of the proposal to satisfy FMPA's preferences. The maximum score allocated to each criterion will be weighted such that the relative importance of each criterion is reflected in the proposal's total non-price score.

The following criteria will be assessed in the detailed evaluation stage:

Competitiveness .....FMPA prefers proposals that offer pricing mechanisms that will assure that the proposed sale will remain competitively priced in comparison to other wholesale power sales in the region.

Flexibility.....FMPA prefers proposals that would provide FMPA with sole rights to extend the contract at the end of the initial term at a predetermined price. Proposals are also preferred which do not impose constraints with respect to load factor, minimum demand, etc. and that can begin delivery of capacity and energy prior to January 1, 2011.

Firm Supply.....FMPA prefers proposals that offer assurances relating to resource reliability and transmission availability and provide financial security to cover penalties for non-performance. For reliability purposes, FMPA also prefers proposals with multiple units.

Dispatchability .....FMPA prefers proposals that are fully dispatchable by FMPA.

Technology .....Proposals utilizing commercially proven and diverse technologies are preferable.

Environmental Impact.....The potential environmental impacts to FMPA from the

Copyright 2007, R. W. Beck, Inc.
All Rights Reserved

purchases are difficult to quantify, but where a clear demonstration can be made by the Proposer that a particular proposal will reduce environmental impacts to FMPA compared to other alternatives, this will be taken into consideration.

From this detailed analysis, proposals will be ranked. A short-list of proposals will be developed and Proposer(s) will be selected for participation in negotiations. The Proposer(s) selected will be notified for commencement of negotiations.

Selection and elimination of proposals and subsequent notification of Proposers at all stages of the evaluation will be at FMPA's discretion. FMPA intends to notify Proposers of those proposals that are eliminated from further consideration under this solicitation within a reasonable amount of time.

21. RFP Forms

Form 1 -	Notice of Intent to Bid Form
Form 2 -	Proposal Summary Form
Form 3 -	Minimum Requirements Form
Form 4 -	Proposal Pricing Form
Form 5 -	Check-List
Attachment A	Required Data for Proposal

Copyright 2007, R. W. Beck, Inc.
All Rights Reserved

FLORIDA MUNICIPAL POWER AGENCY

Notice of Intent to Bid Form

Due: July 16, 2007 (3:00 PM EPT)

Date:_____

Company Name: _____

Name of Contact Person: _____

Mailing Address: _____

_____

Telephone: _____

Fax: _____

E-Mail: _____

Agreement Term: _____

Name of Interconnecting Utility: _____

Location of Proposed Project: _____

Power Generation Technology: _____

Primary Fuel: _____

Bidder Classification: Type of Bidder (Utility, Qualified Facility, Exempt Wholesale Generator, Power Marketer, etc.):

_____

Bidder Qualifications: Describe similar power supply services provided by stating: capacity, location, contract commencement date, contract term, etc.

(Attach additional sheets as needed)

_____

_____

_____

_____

_____

_____

Copyright 2007, R. W. Beck, Inc.
All Rights Reserved

FLORIDA MUNICIPAL POWER AGENCY

Notice of Intent to Bid Form

Due: July 16, 2007 (3:00 PM EPT)

Is there any information on this form considered to be confidential or proprietary? *(Please Describe).*

_____

_____

Bidder's Signature: _____
(Duly Authorized)

Copyright 2007, R. W. Beck, Inc.
All Rights Reserved

FLORIDA MUNICIPAL POWER AGENCY

Proposal Summary Form

1. Company _____
2. Name of Utility for Interconnection _____
3. Name of Contact _____
4. Mailing Address _____
5. Telephone _____
   Fax _____
   E-Mail _____
6. Proposed Contract Start Date _____
7. Proposed Contract End Date _____
8. Brief Description of Proposal _____

Nameplate Rating (MW)	Unit Firm Dependable Rating-Summer (MW)	Unit Firm Dependable Rating-Winter (MW)	Equivalent Forced Outage Rate (EFOR)[1]	Amount of Unit Presently Under Contract to Others (MW)	Annual Hours Maintenance	Projected Capacity Factor [2]
(a)	(b)	(c)	(d)	(e)	(f)	(g)

[1] Equivalent forced outage rate calculated in accordance with NERC Guidelines.

[2] Based on Unit Firm Dependable Rating - Summer.

Copyright 2007, R. W. Beck, Inc.
All Rights Reserved

FLORIDA MUNICIPAL POWER AGENCY

Proposal Summary Form

9. Control Area(s) in which potential resources may be located.

10. Certification: The bidder hereby certifies that all of the statements and representations made in this proposal package, including attached documents, are true to the best of the bidder's knowledge and belief. The bidder agrees to be bound by its representations and the terms and conditions of the Request for Proposals:

Signed: _____

(Typed): _____

Title: _____
(Duly Authorized)

Date: _____

Copyright 2007, R. W. Beck, Inc.
All Rights Reserved

FLORIDA MUNICIPAL POWER AGENCY

Minimum Requirements Form

In submitting this form, we agree to the items below and/or have provided documents to attest to the information provided as requested below. We have also provided references to the proposal in the form of section numbers, page numbers, etc., for information relating to each item.

Name of Company: _____

Duly Authorized Signature: _____ _____
(Date)

Each bidder must demonstrate the following by providing appropriate information in the proposal:

1. The proposal contains the appropriate Proposal Fee in accordance with Section 9.
2. The proposal is for at least 1 MW and begins delivery no later than January 1, 2011.
3. The proposal shall remain valid to the later of March 28, 2008, or the date of receipt of all regulatory approvals required for the proposal and any related transmission service.
4. Proposals for firm capacity and energy are priced inclusive of the Proposer supplying and arranging for all third party transmission into the FMPA system (qualified network resource under FPL's and/or PEF's Open Access Transmission Tariff) and located in the State of Florida. The Proposer has identified the means of assuring firm delivery of capacity resources.
5. The Proposer has agreed to pay for all necessary transmission upgrades to provide for interconnection and delivery service to the FMPA system.
6. For proposals involving a sale to more than one utility from the same resource(s) identified as supplying the sale to the FMPA, FMPA's rights to the output shall be equal to, or greater than, the rights of all other customers served by the resource(s).
7. The Proposer ensures that all emissions allowance requirements will be satisfied and that any associated costs shall be borne by the Proposer.
8. The Proposer demonstrates ownership or contractual rights to the generating system capacity which is identified as supplying the sale.
9. Resources providing the proposed firm capacity and energy, whether an existing plant or proposed new resources, must be in operation at least two (2) months prior to the start date of the proposed power supply.

Copyright 2007, R. W. Beck, Inc.
All Rights Reserved

FLORIDA MUNICIPAL POWER AGENCY

Minimum Requirements Form

10. The Proposer has completed the appropriate RFP Forms 1 through 4. All forms requiring a signature must be signed by a duly authorized official representing the Proposer.

11. The Proposer has provided a Letter of Commitment to establish an acceptable Proposal Security as solely determined by FMPA within ten (10) days of being notified that his proposal is on the short-list of proposals.

12. Proposers shall have successfully provided under contract to at least one electric utility for a minimum period of one year, similar services to the services they are providing to FMPA and have included information in the proposal to demonstrate this experience.

13. The Proposer agrees to assist FMPA to obtain final contract approval from their respective governing bodies in public sessions, where required.

14. The Proposer agrees to provide a letter of commitment from a financial institution with a credit rating of at least A- by S&P, A3 by Moody's or A- from Fitch to be a guarantor for a Proposal Security to be established by the Proposer equal to five dollars ($5) per kilowatt (kW) of the capacity offered in the proposal within ten (10) days of being notified that the proposal is on the short-list of proposals.

15. Pricing information must be provided by Proposers in sufficient detail for FMPA to fully analyze each proposal.

16. The Proposer must provide agreements and disclose sufficient information relating to the provision of fuels, critical spare parts, technical service and support, and maintenance plans to permit FMPA to evaluate the proposals for reliability.

17. If the Proposer is proposing an energy-only, must take, non-dispatchable, or any other arrangement that would require FMPA to take energy from the Proposer at levels that may not be scheduled by FMPA, then the proposal must contain a projected schedule of energy to be provided under the proposal. Such schedules must contain sufficient detail to permit an analysis of hourly energy patterns by day and month over the proposed contract period.

Copyright 2007, R. W. Beck, Inc.
All Rights Reserved

FLORIDA MUNICIPAL POWER AGENCY

Proposal Pricing Form

Capacity Pricing

Summarize separate capacity components below which comprise the total delivered cost of capacity for each contract year below, expressed in $/kW-month. If the proposal does not provide for a separate capacity charge, indicate "N/A" below.

FMPA						
	Component of Delivered Capacity Rate ($/kW-mo.)					
12 Mo. Period Ending December 31	A	B	C	D	E	Total A-E
2011						
2012						
2013						
2014						
2015						
2016						

Using the previously identified components, describe the methodology for determining the monthly capacity charges including how billing demand is determined. Clearly state whether each cost component is a pass through or contractually fixed.

Copyright 2007, R. W. Beck, Inc.
All Rights Reserved

FLORIDA MUNICIPAL POWER AGENCY

Proposal Pricing Form

Energy Pricing

To the extent that the proposal reflects energy pricing on the basis of a fuel cost and a heat rate, indicate the appropriate values for each contract year below. If the proposal reflects energy pricing consisting of one or more discrete energy components associated with delivery into FMPA, identify the components and resulting total as indicated.

FMPA							
12 Mo. Period Ending December 31	Fuel Cost $/MMBtu *(if applicable)*	Heat Rate MMBtu/MWh *(if applicable)*	Components of Delivered Energy Rate ($/MWh)				
			F	G	H	I	Total F-I
2011							
2012							
2013							
2014							
2015							
2016							

Using previously identified components describe the methodology for determining the monthly energy charge including methodology for determining billing units and any potential adjustments. Clearly state whether each cost component is a pass through or contractually fixed. For pass-through costs, provide applicable caps or indices.

Copyright 2007, R. W. Beck, Inc.
All Rights Reserved

FLORIDA MUNICIPAL POWER AGENCY

Checklist

All RFP Forms checked below have been included as part of the proposal *.

RFP Form 2 - Proposal Summary Form _____

RFP Form 3 - Minimum Requirements Form _____

RFP Form 4 - Pricing Proposal Form _____

Signature of Bidder:

_____

Name of Project:

_____

(*) *RFP Form 1 is the Notice of Intent to Propose Form which is sent to FMPA prior to, and separately from, the proposal.*

Copyright 2007, R. W. Beck, Inc.
All Rights Reserved

ATTACHMENT A

Required Data for Proposal

The following data are required for all renewable capacity and energy proposals as applicable. The required data shall be provided in sections numbered in accordance with the specific items detailed below. Each section should begin on a new page. Information provided by bidders that is not in the requested format, may be disregarded and the proposal rejected for incompleteness. General information (e.g., promotional material, "boiler plate", etc.) may be provided with the proposal, but only the formatted information will be considered. Any proposal that does not contain the requested information may be deemed incomplete and may be rejected in FMPA's sole discretion. FMPA may request additional data or clarifying information from bidders.

A-1 Identity of Bidder Contact

Provide the full name, job title, business address, telephone number, and facsimile number of contact person from whom additional information relating to this proposal may be requested.

A-2 General Description of Proposal

a) Provide a general overall summary of the proposal. Identify and describe the type of proposal being offered.

b) If applicable, describe in detail how the bidder will provide for ancillary services. Describe any additional requirement for remote terminal units (RTU's), communication lines, etc. Bidder will be responsible for cost of procuring, installing and maintaining this equipment.

A-3 Location of Generating Facilities

Identify the geographic location of the applicable generating resource(s) and the transmission system which interconnects these resources.

Copyright 2007, R. W. Beck, Inc.
All Rights Reserved

ATTACHMENT A

Required Data for Proposal

A-4 Capacity and Expected Energy Production

Please verify that FMPA's rights to the output of the generating resources which are to supply capacity and energy to FMPA shall be equal to or greater than the rights of all other firm wholesale customers served by the generating resources. Describe limiting conditions (if any).

Please provide a narrative describing the facility's operating history, if any; construction start date; test operation start date; commercial operation date; monthly capacity factors; non-fuel operation and maintenance expenses; net full load heat rate; availability factor; forced outage rates; maintenance schedule; etc.

A-5 Schedule

If there are any limitations on the availability of capacity, specify the time frame when capacity will be available (or unavailable).

A-6 Proposed Agreement Term

(a) Specify proposed contract term.

(b) Specify any and all proposed provisions for contract renewal, extension, or termination, identifying any and all proposed conditions for the above to occur, including whether such events are proposed to be mutually or unilaterally determined.

A-7 Third Party Information

Identify any other firm capacity and energy commitments during the proposed contract term to other parties, and provide a description of FMPA's rights compared to the rights of the other parties. Provide copies of all existing contracts for sale of power to other parties from the unit (price data and other sensitive information may be deleted from the copies).

Copyright 2007, R. W. Beck, Inc.
All Rights Reserved

ATTACHMENT A

Required Data for Proposal

A-8 Historical Fuel Information

Where applicable, please describe the following:

(a) Primary and alternate fuel source for each generating unit.

(b) Historical monthly average fuel prices in $/MMBtu for each applicable generating unit for the last three (3) years.

(c) Average monthly heat rate by unit, including separately MMBtu's and net generation for the last three (3) years.

A-9 Financial Information

(a) Identify any and all bidder affiliates.

(b) Provide audited financial statements, if available, or other financial statements for the last three years. Such information must be provided for all entities, including affiliates involved in the transaction. For investor owned utilities, this would include as a minimum FERC Forms 1's and SEC 10K Forms. Bidders should also provide where appropriate, the most recent Dunn and Bradstreet report, a description of pending litigation, and the most recent annual report.

Copyright 2007, R. W. Beck, Inc.
All Rights Reserved

ATTACHMENT A

Required Data for Proposal

A-10 Pricing Information

(a) Specify on the RFP Form 4 - Proposal Pricing Form, all proposed payment components and proposed incentive amounts, if any, and the conditions which engage such provisions. FMPA requires that proposals clearly distinguish between energy-based and capacity-based pricing components. Please include all costs including: generation, planning reserves, and third party transmission costs into the FMPA system.

(b) Specify annual payment stream components, whether explicitly specified or driven by escalation factors. If price escalation factors are proposed, please identify what attribute the proposed factor is meant to represent (e.g., general inflation, general economic growth, etc.), proposed index or other source data to define the escalator (e.g., CPI, change in GDP, etc.), and bidder's current projection of the designated escalator for each applicable time period.

(c) If the energy price in the proposal is based on a "pass-through" fuel cost arrangement the bidder should provide an explanation of the relationship of energy pricing to actual fuel costs and show an example calculation. The bidder shall also include such information as: projected prices for each type of fuel used; projected annual amount of MWh contributed and MMBtu's utilized by each resource for the proposed contract period; average net heat rate (HHV) for each contributing resource; fuel transportation costs and contract information explaining how transportation costs are determined; and any information on existing fuel contracts. If any of this information is Proprietary Confidential Business Information, it shall be so indicated by the bidder and FMPA will maintain confidentiality in accordance with Section 13. If the proposed energy price is based on a contractually fixed total energy rate, the bidder shall include all information pertinent to the pricing and its escalation.

Copyright 2007, R. W. Beck, Inc.
All Rights Reserved

ATTACHMENT A

Required Data for Proposal

A-11 Transmission

Any bidder proposing to transmit power and energy over the facilities of a third party will be required by FMPA to provide:

(a) A detailed description of the proposed transmission and interconnection arrangements, including, but not limited to, contract path and estimated cost of such services.

(b) A description of any required new interconnection facilities and estimated costs and cost responsibility for such facilities.

(c) A description of upgrades on the FMPA system and third party transmission systems which may be required to accommodate the project and an estimate of costs.

(d) It is the responsibility of the bidder to make all necessary arrangements and bear all the associated costs of firm transmission service of the power into FMPA. Any required transmission system upgrades required to accommodate the delivery of power under the proposal is also the bidder's responsibility.

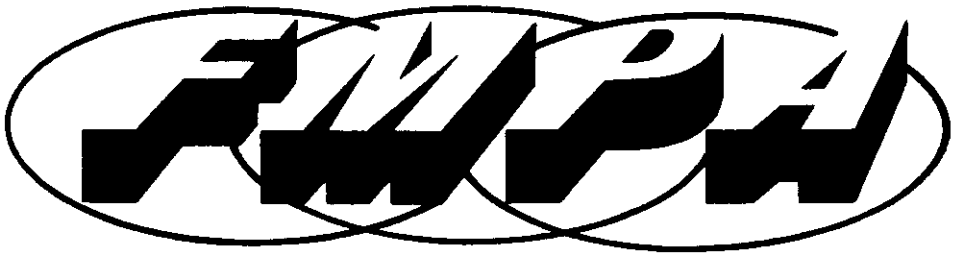
(e) Provide supporting data relating to the availability of long or short term ATC for the proposed transactions.

A-12 Additional Information

Please provide any additional information which the bidder believes will assist FMPA in an accurate and fair evaluation of the proposal.

Copyright 2007, R. W. Beck, Inc.
All Rights Reserved

Appendix C
Request for Proposals for Solar Photovoltaic Equipment or Power Purchase Agreement



F L O R I D A M U N I C I P A L P O W E R A G E N C Y

REQUEST FOR PROPOSALS

FOR

Solar Photovoltaic Equipment or Power Purchase Agreement

Florida Municipal Power Agency
8553 Commodity Circle
Orlando, Florida 32819-9002
(407) 355-7767 Fax (407) 355-5796

Request for Proposal No. 2007-106

December 2007

REQUEST FOR PROPOSALS

(This is not an order)

RETURN

Florida Municipal Power Agency
TO: 8553 Commodity Circle
Orlando, Florida 32819
Attn: Tom Reedy

RFP FMPA 2007-106

Date Issued: December 5, 2007

Telephone: (407) 355-7767

SEALED PROPOSALS MUST PHYSICALLY BE IN THE FLORIDA MUNICIPAL POWER AGENCY OFFICE PRIOR TO PROPOSAL OPENING AT 1:00 P.M. ON JANUARY 7, 2008, WHICH WILL BE IN THE FMPA 1ST FLOOR CONFERENCE ROOM LOCATED IN THE FMPA BUILDING AT 8553 COMMODITY CIRCLE, ORLANDO, FLORIDA 32819.

- Proposals shall be submitted along with the provided Proposer Information Form which must be manually signed.
- Proposals shall be sealed in an envelope with the proposal number, opening date, and time clearly indicated.
- Proposals received after the opening date and time will be rejected and returned unopened.
- The attached Invitation shall become part of any purchase order resulting from this Request for Proposal.

DESCRIPTION

December 2007

FLORIDA MUNICIPAL POWER AGENCY
REQUEST FOR PROPOSALS FOR SOLAR PHOTOVOLTAIC EQUIPMENT OR POWER PURCHASE AGREEMENT

See attached Request for Proposal, General Conditions, Specifications, and Proposal Forms for detailed description.

It is the intent and purpose of the Florida Municipal Power Agency that this Request for Proposal promotes competitive bidding. It shall be the proposer's responsibility to advise if any language, requirements, etc. or any combination thereof, inadvertently restricts or limits the requirements stated in this Request for Proposal to a single source. Such notification must be submitted in writing and must be received by not later than ten (10) days prior to the proposal opening date.

ADVERTISEMENT

December 2007

FLORIDA MUNICIPAL POWER AGENCY
REQUEST FOR PROPOSALS FOR SOLAR PHOTOVOLTAIC EQUIPMENT
OR POWER PURCHASE AGREEMENT

FMPA RFP 2007-106

Sealed proposals will be received by the Florida Municipal Power Agency (FMPA), 8553 Commodity Circle, Orlando, Florida 32819 until 1:00 p.m., January 7, 2008, when at that time Proposals will be opened publicly by a FMPA representative.

The proposal is for Solar Photovoltaic Equipment or Power Purchase Agreement as more fully described in the RFP package.

RFP packages for this project may be obtained from FMPA at the above address, by telephone (407) 355-7767, or via Internet download at *http://www.fmpa.com/html/news/rfp/2007-106.pdf*

No proposal may be altered, withdrawn, or resubmitted after the scheduled closing time for receipt of proposals. Proposals received after the day and time stated above will not be considered and will be returned to the proposer unopened.

Proposals will be accepted for Solar Photovoltaic Equipment or Power Purchase Agreement from companies who have established, through demonstrated expertise and experience that they are qualified to provide the equipment and services as specified.

The Florida Municipal Power Agency reserves the right to reject any and all proposals in total or in part and/or to waive defects in proposals.

Roger Fontes
General Manager
Florida Municipal Power Agency

FLORIDA MUNICIPAL POWER AGENCY
Request for Proposals
Solar Photovoltaic Equipment or Power Purchase Agreement

1. Introduction

Florida Municipal Power Agency (FMPA) is interested in installing solar photovoltaic (PV) power systems in several member cities. FMPA and its member cities may install as much as 100 MW over 5 years and desires to establish standard module sizes with associated mounting hardware and inverters. As an alternative, FMPA is also interested in a Power Purchase Agreement for similar amounts. As such, FMPA invites sealed responses from qualified firms for the provision of the necessary equipment and services as more fully described in Section 4.

2. FMPA Description

Formed by the Florida Legislature in February 1978, the Florida Municipal Power Agency is a non-profit, joint action agency created to serve the needs of municipal electric utilities in Florida. Of the 33 municipal systems in the State, 30 are FMPA members who participate at varying levels in Agency activities.

Member utilities of the Agency serve approximately 750,000 customers. Each member appoints one representative to the Board of Directors which governs the Agency's activities. Currently FMPA has five power supply projects and one pooled financing project. Fifteen members currently purchase all of their power requirements from the Agency (All-Requirements Project or ARP). Five members participate in other FMPA power supply projects.

3. The All Requirements Project

Under the ARP, FMPA currently provides all the power requirements (above certain excluded resources) for fifteen of its members. Initially, the first five members of the ARP were non-generating utilities which had previously received all of their power requirements from full requirements contracts with either Florida Power & Light (FPL) or Progress Energy Florida (PEF). The most recent members, Kissimmee Utility Authority and the City of Lake Worth, joined the ARP in 2002. A list of ARP member cities is included as Appendix A.

Current supply side resources for the ARP are classified into four main areas, the first of which is nuclear capacity. A number of the ARP members own small amounts of capacity in PEF's Crystal River Unit 3. A number of ARP members also participate in the FMPA St. Lucie Project providing them capacity and energy from St. Lucie Unit No. 2. These nuclear resources are referred to as "Excluded Resources." The ARP provides the balance of capacity and energy requirements for the members with participation in these nuclear units. The nuclear units are considered in the capacity planning for the ARP.

The second category of resources is owned generation. This category includes generation that is solely or jointly owned by the ARP as well as ARP member participation in the FMPA Stanton, Tri-City, and Stanton II Projects.

The third category of resources is participant-owned generation. Capacity included in this category is generation owned by the ARP Participants either solely or jointly. FMPA purchases this capacity from the ARP Participants and then commits and dispatches the generation as a part of the ARP portfolio of power-supply resources to meet the total requirements of the ARP.

The fourth category of resources is purchased power. This includes power purchased directly by the ARP as well as existing purchase power contracts of individual ARP Participants, which were entered into prior to the ARP Participant joining the ARP.

4. General Description of Services Sought

FMPA is soliciting proposals for solar photovoltaic (PV) equipment (panels, inverters, and mounting hardware) for as much as 100 MW over a 5 year period. In the first year (2008), however, FMPA intends to install 10 MW of PV power systems at selected FMPA locations. FMPA is seeking a firm or a team of firms to provide cost effective PV solar power systems and establish a long term relationship with the solar PV developer. At this time and for the purpose of this RFP, the proposer should assume installing equipment in 300 - 500 kW blocks.

The Proposer has the option of providing the following proposals to FMPA:

I. Solar PV equipment only as described below or a
II. Turnkey installation or a
III. Solar purchased power contract

The selected bidder will be asked to assist FMPA to further develop the project depending on the success of the initial program.

I. Solar PV equipment:

FMPA will accept bids for solar modules, inverters, mounting hardware (ground mount and roof mount) and monitoring equipment either individually or as a package. With this proposal, installation of the PV power system would be performed by FMPA. All PV power equipment included in the proposal must have a design review and approval from the Florida Solar Energy Center (FSEC). There are no fees associated with this design and approval.

Prices for certain wind conditions i.e. 110/ 120/ 130/ 140 mph wind should be included as part of the proposal, since FMPA has not yet selected the PV sites. Prices for 500 kW roof-mount equipment assuming 110/ 120/ 130/ 140 mph wind should be provided in addition to prices for 500 kW ground-mount assuming 110/ 120/ 130/ 140 mph wind.

System warranties must be provided on the individual components. A minimum of a 5 year minimum warranty on the equipment must be provided. The method for implementing a warranty provision must be clearly established and handled by the system supplier as the single point of contact for warranty services.

Solar Module:

The preferred panel will be a crystalline panel (either single or poly crystalline) and preference will be given to this technology. Other panel technology will be evaluated against this preference. The PV modules must meet industry-accepted standards for performance, reliability, safety. Evidence to support these criteria must be contained in the supplier's System Manual, which shall include all applicable information concerning the equipment and installation. PV modules and panels must be listed and in compliance with UL standard 1703, Standard for Safety: Flat-Plate Photovoltaic Modules and Panels. PV modules must also meet or exceed IEC 61215 and any other relevant standards.

The PV equipment must be able to withstand high wind loads and potential damage from flying debris.

Inverters:

A single inverter or a cluster of inverters rated for a total output of between 300 kW and 500 kW will be preferred. The inverter(s) must be listed and in compliance with Underwriters Laboratories (UL) 1741-2005, "Inverters, Converters, Controllers, and Interconnection System Equipment for Use with Distributed Energy Resources," and all elements of the IEEE 1547 interconnection standards.

Hardware:

Both roof mount and ground mount hardware systems are desired. Generally, FMPA is interested in fixed mounts (non tracking) but will entertain responses proposing tracking systems. The system hardware must be in compliance with UL 1741.

Monitoring Equipment:

The proposal shall also include a web-based data acquisition and display system that allows FMPA to monitor, analyze and display historical and real-time solar electricity generation data for all installed sites. The system shall allow FMPA to monitor as a minimum, system performance, system availability, capacity factor and degradation.

II. Turnkey Installation:

Proposals will also be accepted for a turnkey installation. The selected bidder shall design and engineer the solar PV systems to maximize the solar energy resources at selected sites. The following outlines the general requirements of the bidder for this type of project:

- Provide and install complete PV power system
- All PV power system designs supplied for this project must have a design review and approval from the Florida Solar Energy Center (FSEC)
- Specify layout and location of the system at each site for the purpose of this bid, assume a "standard" greenhouse site conditions with no unused geotechnical or environmental issues.
- Must install similar systems and equipment at each site in order to reduce cost and improve reliability
- Interconnect to the utility grid
- Deliver, assemble and install the equipment at each site
- Conduct acceptance testing on each system and a minimum of one-hour training for each site on the operation and maintenance of the system
- Provide required documentation and System Manual
- Minimize the risk of vandalism, theft and personal injury in the installation and operation of the system
- Due to possible high wind loads and subsequent potential for damage from flying debris, all PV arrays must be securely installed to the ground or roof structure (as appropriate) as dictated by site conditions. Since FMPA has not yet selected the PV sites, the proposer should provide prices assuming 110/ 120/ 130/ 140 mph wind.
- All PV arrays should be oriented in such a way as to maximize annual energy production.

Turnkey Project System Configuration and Operational Requirements

Each PV power system covered in this RFP shall include an array of PV modules and support structures and enclosure, an inverter and associated balance-of-system (BOS) components including wiring, conduit, over current devices, surge suppression and grounding equipment, load

sub panels and metering equipment. The selected bidder shall supply all equipment, materials, permits and labor necessary to install the solar PV systems and integrate them with other power sources.

The selected bidder shall install PV modules, inverters and other components that meet the Florida Solar Energy Center Standards.

Turnkey Project Electrical Interconnections
The selected bidder shall supply and install all equipment required to interconnect the solar PV systems to the utility distribution system. The selected bidder shall fulfill all application, study, and testing procedures to complete the interconnection process. All costs associated with utility interconnection shall be borne by the selected bidder.

Monitoring
The selected bidder shall provide a turnkey data acquisition and display system that allows FMPA to monitor, analyze and display historical and live solar electricity generation data for all installed sites. The system shall allow FMPA to monitor as a minimum, system performance, system availability, capacity factor and degradation. The cost for the monitoring system shall be separately itemized.

Turnkey Project Commissioning and Acceptance Test

- During the start-up, FMPA and/or its independent engineer, shall observe and verify each system's performance.

- Required commissioning and acceptance test services includes: starting up the solar PV systems until it achieves the performance requirements and conducting the successful delivery of power within thirty days following completion of a system.

Turnkey Project Operation and Maintenance Manuals, and As-Built Drawings:
The selected bidder shall provide 2 sets of site-specific operation, maintenance, and parts manuals for each installed solar PV system. The manuals shall cover all components, options, and accessories supplied. They shall include maintenance, trouble-shooting, and safety precautions specific to the supplied equipment at that site. The bidders shall also provide 2 sets of as-built drawings in AutoCAD 14 or higher. These requirements shall be delivered prior to acceptance of the site-specific system.

Warranties and Guarantees:

System warranties must be provided on the individual components. A minimum of a 5 year minimum warranty on the equipment must be provided. The method for implementing a warranty provision must be clearly established and handled by the system supplier as the single point of contact for warranty services.

III. Purchase Power Contract:

FMPA will also accept a long-term Purchased Power Agreement ("PPA") of 10 years or longer from a 3rd party solar PV project with an option to purchase and own the project at a future date. Under a PPA, FMPA would only pay for the energy actually delivered from the project. FMPA encourages the submission of innovative contract structures and will consider other contract arrangements. FMPA will not have any preferred panel technology with a purchase power contract.

5. RFP Schedule

FMPA's timetable for this Request For Proposal (RFP) process is shown below. Note that all times shown are based on Eastern Daylight Savings time (EDT) or Eastern Standard Time (EST), as appropriate; however, the dates shown are only estimates and may be modified at any time by FMPA.

Public Notice of RFP	December 5, 2007
RFP Available for Distribution	December 5, 2007
Sealed Proposal(s) Due Date	January 7, 2008 at 1:00PM
Proposer(s) Selected	January 21, 2008
Approval and Ratification by FMPA Executive Committee	January 24, 2008

6. Notice to Proposers

Sealed responses will be received until 1:00 P.M. (Eastern time) on January 7, 2008 ("Due Date") at the offices of Florida Municipal Power Agency. Each proposer is required to submit a Proposer Information Form (included in this RFP package), and any other information necessary to allow a complete evaluation of the response. Registered respondents will be notified through the issue of RFP addenda of any change in the Proposal Due Date or other necessary revision to information contained in this RFP. This RFP and all addenda will be posted on FMPA's web site, *http://www.fmpa.com/html/news/rfp/2007-106.pdf*. FMPA reserves the right to reject all responses received after the Due Date.

One original and five (5) copies of the response package should be sealed and delivered to the following address:

Mr. Tom Reedy
AGM, Member Services
Florida Municipal Power Agency
8553 Commodity Circle
Orlando, Florida 32819

"Solar Photovoltaic Equipment or Power Purchase Agreement, FMPA RFP 2007-106" must be clearly legible on the outside of the sealed envelope.

7. Duration of Offer

Proposals submitted in response to this RFP are irrevocable for one hundred twenty (120) days following the closing date. This period may be extended at FMPA's request only by written agreement of the proposer. The content of this RFP and the proposal of the successful proposer will be included by reference in any resulting contract.

8. Right of Rejection

This RFP is not an offer establishing any contractual rights. This solicitation is solely an invitation to submit proposals.

FMPA reserves the right to:

- Reject any and all responses to this RFP;
- Waive any requirement in this RFP;
- Not disclose the reason for rejecting a response;
- Not select the proposal with the lowest price; and
- Seek and reflect clarifications to responses

9. Proposal Contents

Proposers are to include with their proposal a complete description of their understanding of the equipment and services requested. This description should be as definitive as possible to allow reasonable understanding and evaluation of the proposal.

The proposal should include a description of any special qualifications of the personnel who will be providing services which are indicative of working familiarity with providing the requested services and any experience with municipalities or municipal electric utilities.

Proposers should identify the specific details of how they will provide the equipment and services outlined in Section 4. The following information should be provided:

a. A listing of previous clients that have received similar equipment and services to those outlined by this RFP. The listing should include a description of the PV resource offered, the amount of capacity or energy involved, and a contact name and telephone number.

b. Firm name, description of core business services and primary client base and the name of the firm's parent company, if applicable. If the firm has an office in Florida, give the location (address and phone number) and identify the office(s) that will be assigned to this project, if appropriate. If the respondent is an affiliation of two or more independent companies, identify each company, their role in this project, and provide the information described above for each company.

c. The cost of the equipment and services bid.

d. Describe how your firm could assist FMPA and its members in refining their plans for PV capacity.

e. Describe any other value added services your firm can bring to FMPA and its members.

f. Indicate the time required to deliver the equipment or to complete the work (as appropriate) outlined in Section 4. While a specific schedule will be part of the negotiations with the top ranked firm(s), each proposer should provide a discussion, based on their knowledge of the industry, on the general time requirements.

g. Any other information that will assist FMPA in evaluating the proposal.

10. Interpretations and Addenda

All questions regarding interpretation of this RFP, technical or otherwise, must be submitted in writing to the following:

By Fax:	Mr. Tom Reedy (407) 355-5794
By Mail or Courier:	Mr. Tom Reedy AGM, Member Services Florida Municipal Power Agency 8553 Commodity Circle Orlando, Florida 32819
By E Mail:	*tom.reedy@fmpa.com*

Only written responses provided by FMPA to proposers' questions will be considered official. A verbal response by FMPA will not be considered an official response. Written responses to questions and requests for interpretations will be provided to all proposers. Copies of all addenda issued in connection with this RFP will be sent to all potential proposers and posted on FMPA's web site.

11. Errors, Modifications or Withdrawal of Proposal

Each proposer should carefully review the information provided in the RFP prior to submitting a response. The RFP contains instructions which should be followed by all respondents. Modifications to responses already received by FMPA will only be accepted prior to the Due Date. Responses may be withdrawn by giving written notice to FMPA prior to the Due Date.

12. Proprietary Confidential Business Information

All responses shall become property of FMPA. FMPA will not disclose to third parties any information that is clearly labeled "Proprietary Confidential Business Information" in a response unless such disclosures are required by law or by order of the court or government agency having appropriate jurisdiction. Each page of Proprietary Confidential Business Information must be clearly labeled "PROPRIETARY CONFIDENTIAL BUSINESS INFORMATION" at the top of the page. FMPA reserves the right to disclose information contained in responses to its consultant(s) for the sole purpose of assisting in the proposal evaluation process. FMPA will require the consultant(s) to maintain the confidentiality of the document.

13. Proposer Qualifications

FMPA will accept responses from firms knowledgeable in providing the services desired. Proposers unfamiliar to FMPA may be required to provide proof of experience.

14. Default and Damages Provisions

FMPA will negotiate the conditions of default and damages with the successful proposer. The respondent is requested to include default and damages provisions in its proposal.

15. Evaluation Process

The responses will be evaluated based on information provided by each respondent by the Due Date. No additional data will be considered after the Due Date, except for clarifications requested by FMPA. The first stage of the evaluation process for qualified proposers will consist of a check of each proposal against the minimum requirements, as listed in this section of the RFP. All respondents that meet the minimum requirements will then be evaluated and ranked according to FMPA's interpretation of the responses submitted and FMPA's needs.

Selection and rejection of responses and notification of respondents at all stages will remain entirely within FMPA's discretion. FMPA intends to notify respondents not selected under this solicitation within a reasonable amount of time.

Minimum Requirements

Each response must satisfy certain minimum requirements before it will receive any further evaluation. The respondent must demonstrate in its submittal that the following minimum requirements have been met:

1) The proposer must supply a completed Proposer Information Form.

2) Information required by Section 9 (a)

3) Information required by Section 9 (b)

4) Information required by Section 9 (c)

Additional Requirements

In addition to the above minimum requirements, FMPA will consider all other information provided as listed in Section 9 of this RFP in the selection and ranking of the proposals.

Evaluation Criteria

A score will be assigned to each of the criteria described in Section 9 based on the extent to which the response satisfies FMPA's preferences. The total score will be used to determine the ranking of proposals.

16. Public Entity Crimes Statement

Pursuant to Section 287.133(2)(a), FLORIDA STATUTES, all respondents should be aware of the following:

"A person or affiliate who has been placed on the convicted vendor list following a conviction for a public entity crime may not submit a bid on a contract to provide any goods or services to a public entity, may not submit a bid on a contract with a public entity for the construction or repair of a public building or public work, may not submit bids on leases of real property to a public entity, may not be awarded or perform work as a contractor, supplier, subcontractor, or consultant under a contract with any public entity, and may not transact business with any public entity in excess of the threshold amount provided in Section 287.017, for CATEGORY TWO for a period of 36 months from the date of being placed on the convicted vendor list."

17. Collusion

By offering a submission pursuant to this Request for Proposals, the respondent certifies the respondent has not divulged, discussed, or compared his response with other respondents and has not colluded with any other respondent or parties to this response whatsoever. Also, the respondent certifies, and in the case of a joint response, each party thereto certifies, as to his own organization, that in connection with this response:

(1) Any prices and/or cost data submitted have been arrived at independently, without consultation, communication, or agreement for the purpose of restricting competition, as to any matter relating to such prices and or cost data, with any other respondent or with any competitor.

(2) Any prices and/or cost data quoted for this response have not knowingly been disclosed by the respondent and will not knowingly be disclosed by the respondent prior to the scheduled opening directly or indirectly to any other respondent or to any competitor.

(3) No attempt has been made or will be made by the respondent to induce any other person or firm to submit or not to submit a response for the purpose of restricting competition.

(4) The only person or persons interested in this response, principal or principals is/are named therein and that no person other than therein mentioned has any interest in this response or in the contract to be entered into and;

(5) No person or agency has been employed or retained to solicit or secure this contract upon an agreement or understanding for a commission, percentage, brokerage, or contingent fee excepting bona fide employees or established commercial agencies maintained by the Respondent for the purpose of doing business.

Appendix A

Member Cities of the All Requirements Project

Bushnell
Clewiston
Fort Meade
Fort Pierce
Green Cove Springs
Havana
Jacksonville Beach
Key West
Kissimmee
Lake Worth
Leesburg
Newberry
Ocala
Starke
Vero Beach

PROPOSER INFORMATION FORM
FMPA RFP 2007-106

_____ We DO NOT take exception to the Proposal Specifications.

_____ We TAKE exception to the Proposal Specifications as follows:

_____

_____

_____

_____

Company Name:

_____

By: _____
(Authorized Person's Signature)

_____
(Print or type name and title of signer)

Company Address

_____

_____

Telephone Number: Toll Free Number:

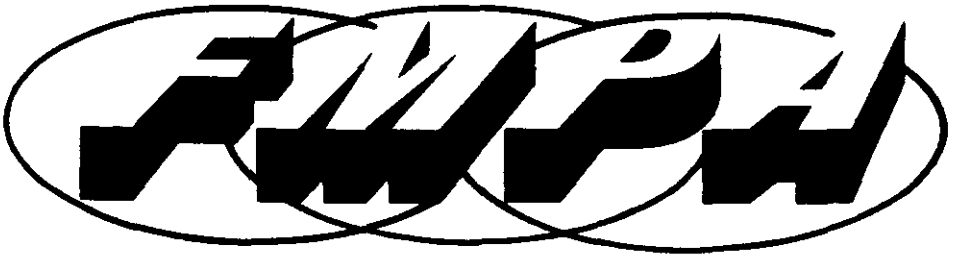
_____

Email: _____

Fax Number: _____

Date:

Appendix D
Request for Proposals for Demand-Side Management Resources



FLORIDA MUNICIPAL POWER AGENCY

REQUEST FOR PROPOSALS
FOR
Demand Side Management Resources

Florida Municipal Power Agency
8553 Commodity Circle
Orlando, Florida 32819-9002
(407) 355-7767 Fax (407) 355-5796

Request for Proposal No. 0607D

July 2007

REQUEST FOR PROPOSALS

(This is not an order)

RETURN

Florida Municipal Power Agency
TO: 8553 Commodity Circle
Orlando, Florida 32819
Attn: Tom Reedy

RFP FMPA 0607D

Date Issued: July 27, 2007

Telephone: (407) 355-7767

SEALED PROPOSALS MUST PHYSICALLY BE IN THE FLORIDA MUNICIPAL POWER AGENCY OFFICE PRIOR TO PROPOSAL OPENING AT 1:00 P.M. ON SEPTEMBER 26, 2007, WHICH WILL BE IN THE FMPA 1ST FLOOR CONFERENCE ROOM LOCATED IN THE FMPA BUILDING AT 8553 COMMODITY CIRCLE, ORLANDO, FLORIDA 32819.

- Proposals shall be submitted on the forms provided and must be manually signed.
- Proposals shall be sealed in an envelope with the proposal number, opening date, and time clearly indicated.
- Proposals received after the opening date and time will be rejected and returned unopened.
- The attached Invitation shall become part of any purchase order resulting from this Request for Proposal.

DESCRIPTION

July 2007

FLORIDA MUNICIPAL POWER AGENCY
REQUEST FOR PROPOSALS FOR DEMAND SIDE MANAGEMENT RESOURCES

See attached Request for Proposal, General Conditions, Specifications, and Proposal Forms for detailed description.

It is the intent and purpose of the Florida Municipal Power Agency that this Request for Proposal promotes competitive bidding. It shall be the proposer's responsibility to advise if any language, requirements, etc. or any combination thereof, inadvertently restricts or limits the requirements stated in this Request for Proposal to a single source. Such notification must be submitted in writing and must be received by not later than ten (10) days prior to the proposal opening date.

ADVERTISEMENT

July 2007

FLORIDA MUNICIPAL POWER AGENCY
REQUEST FOR PROPOSALS FOR DEMAND SIDE MANAGEMENT RESOURCES

FMPA RFP 0607D

Sealed proposals will be received by the Florida Municipal Power Agency (FMPA), 8553 Commodity Circle, Orlando, Florida 32819 until 1:00 p.m., September 26, 2007, when at that time Proposals will be opened publicly by a FMPA representative.

The proposal is for Demand Side Management Resources as more fully described in the RFP package.

RFP packages for this project may be obtained from FMPA at the above address, by telephone (407) 355-7767, or via Internet download at *http://fmpa.com/html/news/reg_rfp_607D.html*

No proposal may be altered, withdrawn, or resubmitted after the scheduled closing time for receipt of proposals. Proposals received after the day and time stated above will not be considered and will be returned to the proposer unopened.

Proposals will be accepted for Demand Side Management Resources from companies who have established, through demonstrated expertise and experience that they are qualified to provide the services as specified.

The Florida Municipal Power Agency reserves the right to reject any and all proposals in total or in part and/or to waive defects in proposals.

Roger Fontes
General Manager
Florida Municipal Power Agency

FLORIDA MUNICIPAL POWER AGENCY
Request for Proposals
Demand Side Management Resources

1. Introduction

The Florida Municipal Power Agency (FMPA) is interested in acquiring demand-side management (DSM) resources. For purposes of this RFP, DSM resources will include any facility, program, or service implemented for retail customers that serves to permanently reduce or shift the time of consumption of electric energy and / or electric demand. As such, FMPA invites sealed responses from qualified firms for the provision of these services as more fully described in Section 4.

2. FMPA Description

Formed by the Florida Legislature in February, 1978, the Florida Municipal Power Agency is a non-profit, joint action agency created to serve the needs of municipal electric utilities in Florida. Of the 33 municipal systems in the State, 30 are FMPA members who participate at varying levels in Agency activities.

Member utilities of the Agency serve approximately 750,000 customers. Each member appoints one representative to the Board of Directors which governs the Agency's activities. Currently FMPA has five power supply projects and one pooled financing project. Fifteen members currently purchase all of their power requirements from the Agency (All-Requirements Project or ARP). Five members participate in other FMPA power supply projects.

3. The All Requirements Project

Under the ARP, FMPA currently provides all the power requirements (above certain excluded resources) for fifteen of its members. Initially, the first five members of the ARP were non-generating utilities which had previously received all of their power requirements from full requirements contracts with either Florida Power & Light (FPL) or Progress Energy Florida (PEF). The most recent members, Kissimmee Utility Authority and the City of Lake Worth, Florida, joined the ARP in 2002. A list of ARP member cities is included as Appendix B.

Current supply side resources for the ARP are classified into four main areas, the first of which is nuclear capacity. A number of the ARP members own small amounts of capacity in PEF's Crystal River Unit 3. A number of ARP members also participate in the FMPA St. Lucie Project providing them capacity and energy from St. Lucie Unit No. 2. These nuclear resources are referred to as "Excluded Resources." The ARP provides the balance of capacity and energy requirements for the members with participation in these nuclear units. The nuclear units are considered in the capacity planning for the ARP.

The second category of resources is owned generation. This category includes generation that is solely or jointly owned by the ARP as well as ARP member participation in the FMPA Stanton, Tri-City, and Stanton II Projects.

The third category of resources is participant-owned generation. Capacity included in this category is generation owned by the ARP Participants either solely or jointly. FMPA purchases

this capacity from the ARP Participants and then commits and dispatches the generation as a part of the ARP portfolio of power-supply resources to meet the total requirements of the ARP.

The fourth category of resources is purchased power. This includes power purchased directly by the ARP as well as existing purchase power contracts of individual ARP Participants, which were entered into prior to the ARP Participant joining the ARP.

4. General Description of Services Sought

FMPA solicits Proposals for demand-side management ("DSM") facilities and/or services that result in permanent reductions of electric energy usage or demand through improvements in efficiency or shifting demand away from on-peak periods to off-peak periods of existing residential, commercial, industrial, and governmental retail customers. Through this RFP, FMPA solicits demand-side proposals as alternatives to construction of new power plants. FMPA seeks a minimum contract term of at least one (1) year for each Demand Proposal, with the term beginning no earlier than June 1, 2008. Definitions for capitalized terms used herein are provided in the attached Appendix A.

This RFP is open to any Proposer who can demonstrate financial credentials appropriate to back the proposal submitted and who has demonstrated ability to provide successful DSM facilities and/or services similar to those being proposed. Proposals will be accepted from qualified third-party providers of DSM facilities and/or services ("Third-Party Proposer") and from retail customers of the ARP members ("Customer Proposer"). Proposals must be able to demonstrate that the total capacity requirements and/or the energy production and purchase power costs of the ARP will be reduced as a direct result of DSM Measures installed by Third Party Proposers in one or more retail electric customer dwellings/facilities within the electric service areas of one or more ARP members or as a direct result of DSM Measures installed by a Customer Proposer that is an electric retail customer of a ARP member.

Proposals submitted by Third Party Proposers must provide On-Peak Demand Reductions of at least 1,000 kilowatts and proposals submitted by Customer Proposers must provide On-Peak Demand Reductions of at least 500 kilowatts. Proposers can meet this requirement by adding the On-Peak Demand Reductions for all proposed DSM Measures, with appropriate adjustments for complementary effects between DSM Measures. Proposers must provide documentation of all calculations used to account for complementary effects between DSM Measures; failure to provide such documentation or failure to perform such calculations when applicable may result in the disqualification of Proposer's proposal.

Proposals submitted by Customer or Third Party Proposers must be able to demonstrate sufficient financial resources to implement the proposed DSM Measure(s). Proposals submitted by Customer Proposers also must demonstrate a firm commitment for installation of the DSM Measure at the Host Customer site. Proposals submitted by Third Party Proposers for installation of DSM Measure(s) at a single Host Customer's facility, or at a limited number of Host Customers' facilities, must be able to demonstrate a firm commitment from the Host Customer(s) for installation of the DSM Measure(s) at the Host Customer(s) site, and must also be able to demonstrate that sufficient financial resources are firmly committed from either the Third Party Provider and/or the Host Customer(s).

Proposals submitted from Third Party Proposers that intend to offer DSM Measures to the general body of retail customers of one or more of the ARP members must submit a comprehensive marketing plan by which it will inform these customers of the availability and advantages of the DSM Measures proposed. Marketing plans, at a minimum, must include: identified target market, Electric

End-Use appliance/process saturation, eligible customers, customer acceptance, DSM Measure diffusion by month and year, source and validity of market research assumptions, general marketing tactics, and sample marketing materials (where appropriate).

Proposals that fail to demonstrate sufficient financial resources of the Proposer and/or the Host Customer(s), or fail to demonstrate the existence of a firm commitment on the part of the Host Customer(s), or fail to include an adequate description of the marketing plan may be disqualified from consideration. Successful Proposers will be required to provide adequate security to ensure completion of the installation of the DSM Measure(s) by the beginning of the contract term. The installation period may be extended for Proposers proposing comprehensive DSM programs that will be offered to the general body of retail ratepayers of the ARP members, but only to the extent that such extension is in the best interest of the ARP. If a Proposer offers firm demand and energy reductions, and the Proposer fails to meet its obligations, the Proposer should be prepared to hold FMPA and its members harmless from resulting increased costs incurred by the ARP in obtaining replacement power.

The total amount of DSM Resources that the ARP may ultimately contract for as a result of this RFP will depend upon issues that may include: the relative cost-effectiveness of the Proposals submitted, technical maturity of the proposed DSM Measure(s), coincidence of demand reduction with the ARP peak demands, the complementary effect of demand and energy reductions between Proposals, market potential of DSM Measure(s), and any other factors that FMPA may identify as potentially affecting the cost-effective implementation of DSM in the ARP member systems. FMPA reserves the right to select any, all, or none of the proposals submitted under this RFP.

Even though FMPA is administering this RFP, depending on the nature of the Proposal, a successful Proposer could ultimately execute agreements for DSM facilities and/or DSM services with either FMPA and/or the ARP Member(s). Any successful Proposer may begin the installation of DSM Measures after a final agreement has been reached with FMPA and/or the FMPA Member(s) and the agreement, and a mechanism for the recovery of any costs of FMPA and/or the FMPA Member(s) related to the agreement are approved by the ARP, its members, and any other regulatory authority having jurisdiction. If any successful Proposer elects to begin any construction related to the installation of DSM Measures before the final agreement and a cost recovery mechanism have received such approval, that Proposer will assume any and all risks and liabilities associated with that construction, including but not limited to the removal, at the request of a Host Customer, of any facilities installed if such approval is denied.

Eligible DSM Measures

Proposals may be submitted for the implementation of DSM Measures in the following retail customer categories: residential, commercial, industrial, and governmental. Proposed DSM Measure(s) must affect existing Electric End-Uses. Electric End-Uses being installed in facilities which would be considered Free Riders are not eligible for proposals made in response to this RFP. All DSM Measures must be installed on the premises of the ARP members' electric retail customers. DSM Measure(s) installed outside of the ARP members' electric service territories are not eligible for this RFP.

For the purpose of this RFP, acceptable DSM Measures are those that permanently reduce the demand for electric energy by improving the electrical efficiency of an existing and on-going Electric End-Use, or by shifting existing electric loads from on-peak periods to off-peak periods. Only

technologies that are normally expected to operate during On-Peak Demand hours are eligible for demand reduction payments. Any DSM Measures that reduce electric energy or demand consumption by reducing Host Customer's own production or level of operation (e.g., closing a branch office, downsizing production, etc.) are not acceptable.

Any Energy Efficiency or Load Shifting Measure that is required by law, is required by building or other codes, or in the opinion of FMPA represents standard industry practice, is not eligible.

FMPA reserves the right in its sole discretion to select the DSM Measures that will qualify for consideration. The DSM Measures must be technically proven, commercially available, and subject to measurement and verification. A maintenance and replacement plan must be submitted for any DSM Measure with a Service Life less than the length of any agreement resulting from this RFP.

Proposals ineligible for this RFP could include, but are not limited to, those that:

1. Are neither Energy Efficiency Measures nor Load Shifting Measures;
2. Include self-generation of electricity;
3. Relocate electric load to other facilities or to other utility companies;
4. Shift electric load to load provided by another fuel (e.g., electric water heater being replaced by a natural gas water heater);
5. Reduce customer's production of goods or services; or
6. Result in a loss of functional usefulness of customer equipment or facilities.

Customers currently receiving payments from ARP members for DSM Measure(s) or Programs are ineligible to participate in this RFP. For instance, a customer currently receiving incentives through an interruptible retail rate may not be included in a proposal.

5. RFP Schedule

FMPA's timetable for this Request For Proposal (RFP) process is shown below. Note that all times shown are based on Eastern Daylight Savings time (EDT) or Eastern Standard Time (EST), as appropriate; however, the dates shown are only estimates and may be modified at any time by FMPA.

Public Notice of RFP	July 27, 2007
RFP Available for Distribution	July 27, 2007
Sealed Proposal(s) Due Date	September 26, 2007
Short List of Proposers	November 5, 2007
Proposer(s) Selected	December 21, 2005
Contract Developed and Finalized	Spring, 2008

6. Notice to Proposers

Sealed responses will be received until 1:00 P.M. (Eastern time) on September 26, 2007 ("Due Date") at the offices of Florida Municipal Power Agency. Each proposer is required to submit a Proposer Information Form (included in this RFP package), other forms included in this package as appropriate, and any other information necessary to allow a complete evaluation of the qualifications of the respondent. Registered respondents will be notified through the issue of RFP addenda of any change in the Proposal Due Date or other necessary revision to information contained in this RFP. This RFP and all addenda will be posted on FMPA's web site, *http://fmpa.com/html/news/rfp.html.* FMPA reserves the right to reject all responses received after the Due Date.

One original and five (5) copies of the response package should be sealed and delivered to the following address:

Mr. Tom Reedy
AGM, Member Services
Florida Municipal Power Agency
8553 Commodity Circle
Orlando, Florida 32819

"Demand Side Management Resources, FMPA RFP 0607D" must be clearly legible on the outside of the sealed envelope.

7. Duration of Offer

Proposals submitted in response to this RFP are irrevocable for one hundred eighty (180) days following the closing date. This period may be extended at FMPA's request only by written agreement of the proposer. The content of this RFP and the proposal of the successful proposer will be included by reference in any resulting contract.

8. Right of Rejection

This RFP is not an offer establishing any contractual rights. This solicitation is solely an invitation to submit proposals.

FMPA reserves the right to:

- Reject any and all responses to this RFP;
- Waive any requirement in this RFP;
- Not disclose the reason for rejecting a response;
- Not select the proposal with the lowest price; and
- Seek and reflect clarifications to responses

9. Proposal Contents

Proposers are to include with their proposal a complete description of their understanding of the services requested. This description should be as definitive as possible to allow reasonable understanding and evaluation of the proposal.

The proposal should include a description of any special qualifications of the personnel who will be providing services which are indicative of working familiarity with providing the requested services and any experience with municipalities or municipal electric utilities.

Proposers should identify the specific details of how they will provide the services outlined in Section 4, above. The following information should be provided:

a. A listing of previous clients that have received similar services to those outlined by this RFP. The listing should include a description of the DSM resource offered, the amount of capacity or energy involved, and a contact name and telephone number. Preference will be given to firms with demonstrated experience with Florida municipal utility clients.

b. A description of any special qualifications of the personnel to be providing services which are indicative of working familiarity with the DSM programs. Proposers should submit information documenting qualifications of all team members and the team members that have successfully designed, financed, installed, operated, and maintained similar DSM Measures. FMPA will give preference to proposals with a detailed management plan and identified technical experience and support.

c. Firm name, description of core business services and primary client base and the name of the firm's parent company, if applicable. If the firm has an office in Florida, give the location (address and phone number) and identify the office(s) that will be assigned to this project. If the respondent is an affiliation of two or more independent companies, identify each company, their role in this project, and provide the information described above for each company.

d. Describe how your firm could assist FMPA and its members in refining their plans for DSM programs.

e. Describe any value added services your firm can bring to FMPA and its members.

f. Indicate the time required to complete the work outlined in Section 4. While a specific schedule will be part of the negotiations with the top ranked firm(s), each proposer should provide a discussion, based on their knowledge of the industry, on the general time requirements.

g. Proposers must propose a minimum contract term of at least one (1) year for each Demand Proposal, with the term beginning no earlier than June 1, 2008.

h. Proposers must propose at least 1,000 kW per Proposal from Third-Party Proposers, or at least 500 kW per Proposal from Customer Proposers.

i. Each proposed DSM Measure must be either an Energy Efficiency Measure or a Load

Shifting Measure relating to an existing Electric End-Use. The Proposer must provide a comprehensive description of each DSM Measure, including:

a. Equipment, facility and installation costs for the DSM Measure;

b. Annual maintenance cost for the DSM Measure;

c. Cost to decommission existing equipment and facilities at the Host Customer's site;

d. Service life of the DSM Measure;

e. Plan and projected costs to renew or replace DSM Measure to provide at least 20 years of service;

f. The Host Customer's financial contribution to the implementation and maintenance of the DSM Measure;

g. Projected monthly demand and energy DSM reductions guaranteed by the Proposer;

h. Estimated demand reductions by hour of the day for each month over the term of the Proposal for the following day types: monthly peak day, average typical weekday, and average weekend day.

j. Proposals must include a pricing proposal, which describes the payments the Proposer expects to receive over the term of the Agreement. The pricing proposal shall include an annual capacity price in $/kW for the amount of reduced demand. The pricing proposal shall also include an annual energy price in $/MWh for the amount of reduced energy. The proposed demand and energy pricing should be net of any retail rate savings that the Host Customer(s) may receive that result from the demand and energy reductions. The pricing proposal shall include a description of how the results obtained from the Measurement and Verification Plan ("M&V Plan") will be used to adjust payments made to the Proposer over the term of the proposal. Additionally, the Proposal shall include an assessment of costs to be incurred by the Host Customer for the implementation of the DSM Measure(s). Documentation of the derivation of the Host Customer costs shall be included with all Proposals. These costs will be used in the economic evaluation of the Proposal. FMPA desires proposals that link the timing of payments to the timing of value received by the ARP.

k. Proposals must include an effective Measurement and Verification Plan ("M&V Plan") that will provide the basis for determining the level of demand and energy reductions produced as a result of the DSM Measure implementations. The M&V Plan shall fully describe all calculations and procedures that will be used to determine demand and energy reductions, including, but not limited to: engineering estimates; auditing procedures; pre- and post-installation metering facilities and monitoring and recording procedures; quality assurance procedures; weather adjustments; and any other assumptions or measurements proposed by the Proposer. Additionally, the Proposer shall describe how each of the following factors are addressed by the M&V Plan: Free Riders (as defined in

Appendix A), Free Drivers (as defined in Appendix A), Persistence of reductions, consumption rebound, state and federal efficiency standards and codes, diversity of demand reductions, coincidence with on-peak demands, naturally occurring conservation, degradation of DSM Measure efficiency, age of existing equipment/facilities to be affected by the DSM Measure(s), and projected demand and energy impacts of the existing facilities over the term of the proposal. The Proposer will be expected to submit an annual report on demand and energy reductions, which are calculated consistent with the M&V Plan, prior to receipt of any demand and energy payments to be made by FMPA.

l. Proposals that intend to offer DSM Measures or programs to the general body of retail customers of one the FMPA Members must submit a comprehensive marketing plan. The marketing plan must demonstrate how retail customers will be informed of the availability and advantages of the DSM programs. Marketing plans, at a minimum, must include: identified target market, Electric End-Use appliance/process saturation, eligible customers, customer acceptance, DSM Measure diffusion by month and year, source and validity of market research assumptions, general marketing tactics, and sample marketing materials (where appropriate). Marketing plans that are well researched and documented will be preferred. The marketing plan should demonstrate that there is sufficient market potential to achieve the proposed participation levels and demand and energy reductions. In addition, FMPA will consider the Proposer's plans for penetrating the market, including service area coverage and strategies that are appropriate for the Electric End-Use sector targeted, marketing plans that have been used successfully by the Proposer in previous efforts to market DSM Measures, and marketing plans that clearly describe how all elements of the proposal can be delivered.

m. The financing plan contained in a Proposal is an indicator of whether the project will be adequately funded and thus completed. Information concerning the financing of the proposal should be provided for all Proposals.

10. Interpretations and Addenda

All questions regarding interpretation of this RFP, technical or otherwise, must be submitted in writing to the following:

By Fax:	Mr. Tom Reedy (407) 355-5794
By Mail or Courier:	Mr. Tom Reedy AGM, Member Services Florida Municipal Power Agency 8553 Commodity Circle Orlando, Florida 32819
By E Mail:	*tom.reedy@fmpa.com*

Only written responses provided by FMPA to proposers' questions will be considered official. A verbal response by FMPA will not be considered an official response. Written responses to questions and requests for interpretations will be provided to all proposers. Copies of all addenda issued in connection with this RFP will be sent to all potential proposers and posted on FMPA's web site.

11. Errors, Modifications or Withdrawal of Proposal

Each proposer should carefully review the information provided in the RFP prior to submitting a response. The RFP contains instructions which should be followed by all respondents. Modifications to responses already received by FMPA will only be accepted prior to the Due Date. Responses may be withdrawn by giving written notice to FMPA prior to the Due Date.

12. Proprietary Confidential Business Information

All responses shall become property of FMPA. FMPA will not disclose to third parties any information that is clearly labeled ''Proprietary Confidential Business Information" in a response unless such disclosures are required by law or by order of the court or government agency having appropriate jurisdiction. Each page of Proprietary Confidential Business Information must be clearly labeled "PROPRIETARY CONFIDENTIAL BUSINESS INFORMATION" at the top of the page. FMPA reserves the right to disclose information contained in responses to its consultant(s) for the sole purpose of assisting in the proposal evaluation process. FMPA will require the consultant(s) to maintain the confidentiality of the document.

13. Proposer Qualifications

FMPA will accept responses from firms knowledgeable in providing the services desired. Proposers unfamiliar to FMPA may be required to provide proof of experience.

14. Default and Damages Provisions

FMPA will negotiate the conditions of default and damages with the successful proposer. The respondent is requested to include default and damages provisions in its proposal.

15. Evaluation Process

The responses will be evaluated based on information provided by each respondent by the Due Date. No additional data will be considered after the Due Date, except for clarifications requested by FMPA. The first stage of the evaluation process for qualified proposers will consist of a check of each proposal against the minimum requirements, as listed in this section of the RFP. All respondents that meet the minimum requirements will then be evaluated and ranked according to FMPA's interpretation of the responses submitted and FMPA's needs.

Selection and rejection of responses and notification of respondents at all stages will remain entirely within FMPA's discretion. FMPA intends to notify respondents not selected under this solicitation within a reasonable amount of time.

Minimum Requirements

Each response must satisfy certain minimum requirements before it will receive any further evaluation. The respondent must demonstrate in its submittal that the following minimum requirements have been met:

1) The proposer must supply a completed Proposer Information Form.

2) Information required by Section 9 (a)

3) Information required by Section 9 (c)

4) Information required by Section 9 (j)

5) Information required by Section 9 (k)

Additional Requirements

In addition to the above minimum requirements, FMPA will consider all other information provided as listed in Section 9 of this RFP in the selection and ranking of the proposals.

Evaluation Criteria

A score will be assigned to each of the criteria described in Section 9 based on the extent to which the response satisfies FMPA's preferences. The total score will be used to determine the ranking of proposals.

14. Public Entity Crimes Statement

Pursuant to Section 287.133(2)(a), FLORIDA STATUTES, all respondents should be aware of the following:

"A person or affiliate who has been placed on the convicted vendor list following a conviction for a public entity crime may not submit a bid on a contract to provide any goods or services to a public entity, may not submit a bid on a contract with a public entity for the construction or repair of a public building or public work, may not submit bids on leases of real property to a public entity, may not be awarded or perform work as a contractor, supplier, subcontractor, or consultant under a contract with any public entity, and may not transact business with any public entity in excess of the threshold amount provided in Section 287.017, for CATEGORY TWO for a period of 36 months from the date of being placed on the convicted vendor list."

15. Collusion

By offering a submission pursuant to this Request for Proposals, the respondent certifies the respondent has not divulged, discussed, or compared his response with other respondents and has not colluded with any other respondent or parties to this response whatsoever. Also, the respondent certifies, and in the case of a joint response, each party thereto certifies, as to his own organization, that in connection with this response:

(1) Any prices and/or cost data submitted have been arrived at independently, without consultation, communication, or agreement for the purpose of restricting competition, as to any matter relating to such prices and or cost data, with any other respondent or with any competitor.

(2) Any prices and/or cost data quoted for this response have not knowingly been disclosed by the respondent and will not knowingly be disclosed by the respondent prior to the scheduled opening directly or indirectly to any other respondent or to any competitor.

(3) No attempt has been made or will be made by the respondent to induce any other person or firm to submit or not to submit a response for the purpose of restricting competition.

(4) The only person or persons interested in this response, principal or principals is/are named therein and that no person other than therein mentioned has any interest in this response or in the contract to be entered into and;

(5) No person or agency has been employed or retained to solicit or secure this contract upon an agreement or understanding for a commission, percentage, brokerage, or contingent fee excepting bona fide employees or established commercial agencies maintained by the Respondent for the purpose of doing business.

16. Subcontracted Services

Proposer's response should indicate which, if any, of the services to be provided would be subcontracted by the consultant to independent contractors.

17. Final Contract

Any final contract(s) that result from the response evaluation and negotiation process will be submitted to the Executive Committee of FMPA for approval. It is anticipated that any contract(s) will be approved during the Spring of 2008.

18. Permits and Licenses

Successful proposer(s) will be required to provide proof of any licenses and permits required by Federal, State, or local law or ordinance.

Appendix A

DSM-Related Definitions

Bid Price - the stream of annual payments proposed by Proposer to be paid for Contract DSM Resources.

Customer Proposer — An ARP member customer submitting a proposal to provide DSM Resources that will be completely installed in facilities receiving electric service from an ARP member and owned, operated, or leased by the customer.

Demand-Side Management (DSM) or DSM Measures — Technologies or measures designed to reduce or control the consumption of electricity by Host Customers.

DSM Resources — Demand reductions measured in kilowatts (kW) and associated energy reductions measured in kilowatt-hours (kWh) resulting from the installation of DSM Measures.

DSM Resources Security — Security given by Proposer to ensure that Contract DSM Resources are installed, operational, and verified as operational.

Electric End Use — The result or product of the application of electric energy, including irrigation, refrigeration, lighting, space cooling, space heating, dehumidification, air compression, pumping, curing, drying, heating, melting, cooling, and refining.

Energy Efficiency Measure — A measure that improves the electric efficiency of an existing and on-going Electric End-Use.

Free Driver — Retail customers who undertake DSM activities on their own without participating in a DSM program.

Free Riders — Host Customers that participate in a DSM program implemented by a Proposer who would have undertaken a DSM Measure even if they were not provided an incentive to participate in the Proposer's DSM program.

Host Customer — A retail customer, served by one of the ARP's members, at whose facilities Proposer installs DSM Measures.

Load Shifting Measure — A DSM Measure that shifts existing electrical loads from on-peak periods to off-peak periods.

On-Peak Demand — Integrated hourly demands occurring on week days in the months of June through October, between the hours of 7 AM to 11 PM p.m. EPT.

On-Peak Demand Reductions — The average of the demand reduction during the above-noted On-Peak Demand periods.

Persistence — A measure of the level of demand or energy savings degradation over the life of a DSM measure. Persistence is a function of both consumer behavior and equipment efficiency degradation.

Service Life — The useful life of a DSM Measure installed by a Proposer.

Third Party Proposer — An energy service company or other entity, other than a Customer Proposer, that submits a proposal to provide DSM measures for one or more of the ARP's members' customers.

Appendix B

Member Cities of the All Requirements Project

Bushnell
Clewiston
Fort Meade
Fort Pierce
Green Cove Springs
Havana
Jacksonville Beach
Key West
Kissimmee
Lake Worth
Leesburg
Newberry
Ocala
Starke
Vero Beach

STATEMENT OF NO RESPONSE

General Manager
Florida Municipal Power Agency
8553 Commodity Circle
Orlando, FL 32819

We, the undersigned, have declined to submit a proposal on your Request for Proposals Number 0607D, September 26, 2007, FLORIDA MUNICIPAL POWER AGENCY DEMAND SIDE MANAGEMENT RESOURCES - for the following reasons:

_____We do not offer this service/product.
_____Our schedule would not permit us to perform.
_____Unable to meet specifications.
_____Unable to meet bond requirements.
_____Other

Company Name:

By:
(Authorized Person's Signature)

_____
(Print or type name and title of signer)

Company Address:

Telephone Number:

Toll Free Number:

Fax Number:

Date:

PROPOSER INFORMATION FORM
FMPA RFP 0607D

_____ We DO NOT take exception to the Proposal Specifications.

_____ We TAKE exception to the Proposal Specifications as follows:

_____

_____

_____

_____

_____

Company Name:

_____

By: _____
(Authorized Person's Signature)

_____
(Print or type name and title of signer)

Company Address

_____

_____

Telephone Number: Toll Free Number:

_____

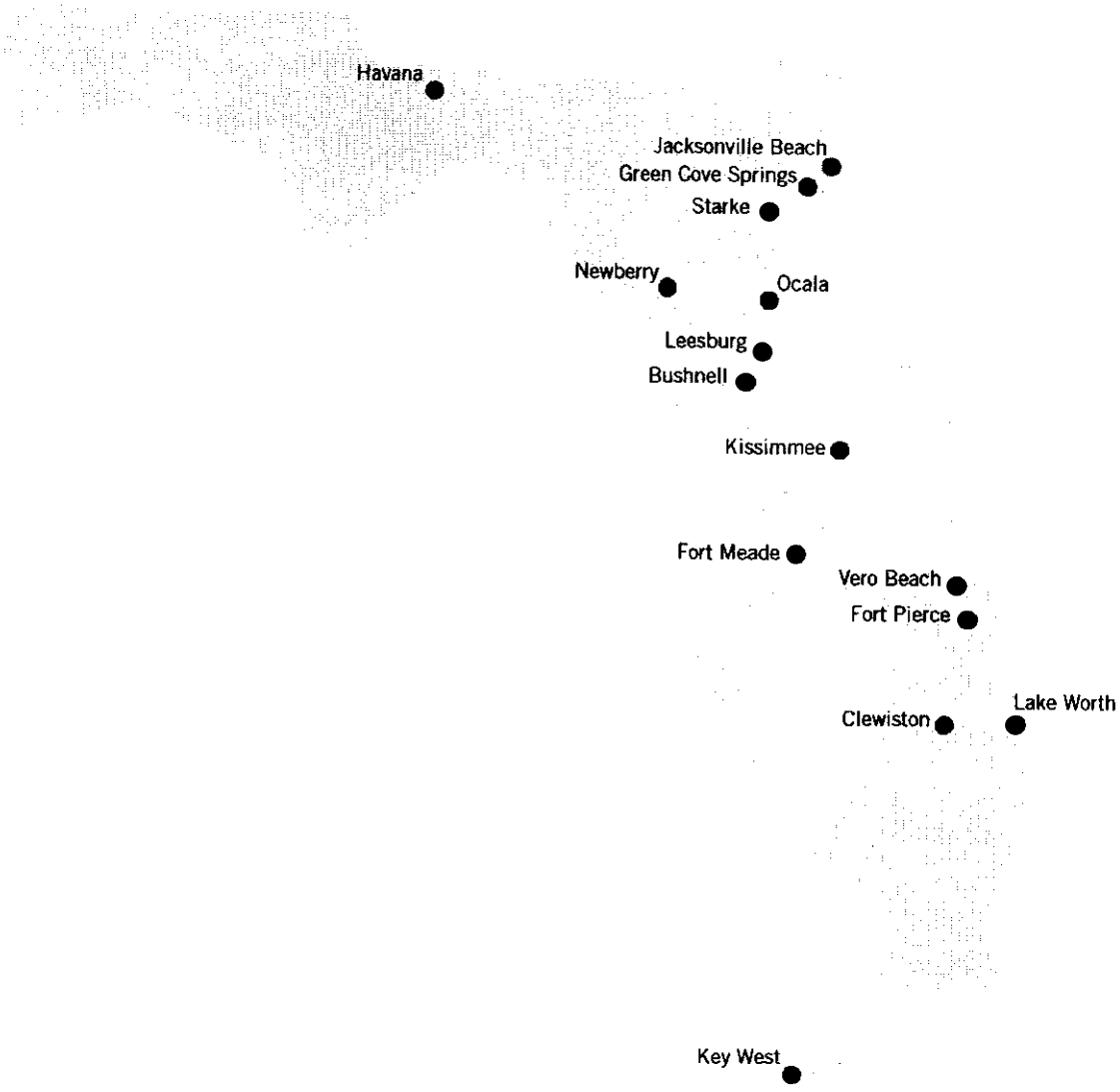
Email: _____

Fax Number:

_____
Date:

ARP Members

The figure below shows ARP Member city locations.



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080253-EM EXHIBIT 4
COMPANY FL Municipal Power Agency (Direct)
WITNESS Roger A. Fontes (RAF-1)
DATE 08-04-08

Pre-Filed Testimony, Reedy
Exhibit ___[TER-1], "ARP's Existing and Approved/Planned Resource Capacity" has been revised as follows (bold items represent changes):

ARP's Existing and Approved/Planned Resource Capacity[1]						
Generating Resources	Summer Rating					
	2008	2009	2010	2011	2012	2013 - 2027
Excluded Resources (Nuclear)[2]	84	84	73	**74**	**84**	**84**
Stanton Coal Plant[3]	222	222	184	184	184	184
Stanton Combined Cycle Unit A[4]	45	45	45	45	45	45
Cane Island 1-3[4]	383	383	383	383	383	383
Indian River CTs	80	80	80	80	80	80
Stock Island 2-4	75	75	75	75	75	75
Key West Native Generation	41	41	41	41	41	41
Kissimmee Native Generation	47	47	47	47	0	0
Lake Worth Native Generation	89	89	89	0	0	0
Vero Beach Native Generation	138	138	0	0	0	0
Treasure Coast Energy Center	296	296	296	296	296	296
Total Generating Capacity[5]	1,500	1,500	1,314	**1,226**	**1,189**	**1,189**
Purchased Power						
PEF Partial Requirements	30	75	120	0	0	0
FPL Long-Term Partial Requirements	45	45	45	45	45	0
Calpine Purchase	100	100	0	0	0	0
Stanton A Purchase[6]	80	80	80	80	80	80
Southern Power Company Power Purchase Agreement	157	157	157	157	157	157
Total Purchased Power Resources[5]	412	457	402	282	282	237
Total Resources[5]	1,912	1,957	1,716	**1,508**	**1,470**	**1,426**

[1] Planned capacity prior to commercial operation of the Central Florida Power Project.
[2] Reduction in 2010 reflects the withdrawal of Vero Beach from ARP. Increase in 2011 reflects planned upgrades.
[3] Reduction in 2010 reflects the withdrawal of Vero Beach from ARP.
[4] Includes FMPA and KUA ownership capacity.
[5] Sums may not match FMPA totals due to rounding.
[6] Includes FMPA and KUA capacity purchased from Southern Company Florida, LLC.

ARP's Existing and Approved/Planned Resource Capacity[1]						
Generating Resources	Summer Rating					
	2008	2009	2010	2011	2012	2013 - 2027
Excluded Resources (Nuclear)[2]	84	84	73	77	77	77
Stanton Coal Plant[3]	222	222	184	184	184	184
Stanton Combined Cycle Unit A[4]	45	45	45	45	45	45
Cane Island 1-3[4]	383	383	383	383	383	383
Indian River CTs	80	80	80	80	80	80
Stock Island 2-4	75	75	75	75	75	75
Key West Native Generation	41	41	41	41	41	41
Kissimmee Native Generation	47	47	47	47	0	0
Lake Worth Native Generation	89	89	89	0	0	0
Vero Beach Native Generation	138	138	0	0	0	0
Treasure Coast Energy Center	296	296	296	296	296	296
Total Generating Capacity[5]	1,500	1,500	1,314	1,229	1,182	1,182
Purchased Power						
PEF Partial Requirements	30	75	120	0	0	0
FPL Long-Term Partial Requirements	45	45	45	45	45	0
Calpine Purchase	100	100	0	0	0	0
Stanton A Purchase[6]	80	80	80	80	80	80
Southern Power Company Power Purchase Agreement	157	157	157	157	157	157
Total Purchased Power Resources[5]	412	457	402	282	282	237
Total Resources[5]	1,912	1,957	1,716	1,511	1,463	1,418

[1] Planned capacity prior to commercial operation of the Central Florida Power Project.
[2] Reduction in 2010 reflects the withdrawal of Vero Beach from ARP. Increase in 2011 reflects planned upgrades.
[3] Reduction in 2010 reflects the withdrawal of Vero Beach from ARP.
[4] Includes FMPA and KUA ownership capacity.
[5] Sums may not match FMPA totals due to rounding.
[6] Includes FMPA and KUA capacity purchased from Southern Company Florida, LLC.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080253-EM **EXHIBIT** 5
COMPANY FL Municipal Power Agency (Direct)
WITNESS Thomas E. Reedy (TER-1)
DATE 08-04-08

RESUME OF

Thomas E. Reedy,

Assistant General Manager of the Power Resources Division

Florida Municipal Power Agency (FMPA)

Qualifications and Experience:

Since March of 2008, Mr. Reedy has served as the Assistant General Manager of the Power Resources Division of FMPA. Prior to his recent position, he was FMPA's Assistant General Manager, Members Services for four years.

Mr. Reedy has 30 years of experience in the electric utility industry. Mr. Reedy joined FMPA in 1995 and has held several positions during his tenure, including Member Services Coordinator, Director of Member Services, and most recently, Assistant General Manager, Member Services. Prior to joining FMPA, he served four years as an executive consultant for Resource Management International, Inc.

His background includes experience in cogeneration development, electric utility planning, electric utility dispatching and operations, forecasting and load research. At FMPA, his responsibilities include power supply and transmission planning, project development, power supply contracts, regulatory affairs, operations, and fuels.

Mr. Reedy holds a bachelor's degree in electrical engineering from the University of Florida in Gainesville, and he is a registered professional engineer in the state of Florida.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080253-EM **EXHIBIT** 6
COMPANY FL Municipal Power Agency (Direct)
WITNESS Thomas E. Reedy (TER-2)
DATE 08-04-08

Employment

History:	1995-Present	FMPA
	1991-1995	Resource Management International, Inc.
Education:	B.S.	Electrical Engineering, University of Florida, Gainesville, FL

RESUME OF

Jonathan P. Nunes, Senior Economist

R. W. Beck, Inc.

Qualifications and Experience:

Mr. Nunes has been with R. W. Beck since 1993. Since joining the firm, he has provided consulting services in the areas of power supply planning, financial planning and analysis, and econometric analysis. In particular, he has been responsible for numerous load forecasts in support of power supply decisions, certificate of need filings, wholesale and retail rate planning, and budgeting for a variety of utilities throughout the United States. Although his work has focused on load-serving electric utilities, Mr. Nunes has also provided consulting services to merchant power plant developers, solid waste collection agencies, local governments, and large industrial manufacturers.

Mr. Nunes has a Master of Arts degree in Applied Economics from the University of Central Florida and a Bachelor of Science degree in Business Administration, Economics from the University of Central Florida.

Power Supply Planning and Analysis

- Long-term Load Forecasting
- Hourly Load Forecasting

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080253-EM EXHIBIT 7
COMPANY Florida Municipal Power Agency
WITNESS Jonathan P. Nunes (JPN-1) (Direct)
DATE 08-04-08

- Power Supply Analyses
- Energy Risk Management

Mr. Nunes has been responsible for numerous long-term electric load forecasts and related analyses for various municipal utilities, joint-action agencies, and cooperatives. These efforts have included the development of forecasting processes from the ground up and the supervision of other staff, including client staff, in prosecuting portions of the analytical work. Mr. Nunes has taken a lead role in the development of forecasting techniques and historical data analyses to develop base-line forecasts and the sensitivity of those forecasts to varying economic and weather assumptions.

Mr. Nunes has also been responsible for the development of hourly load forecasting models for various clients to facilitate the scheduling of power supply resources and forward sales. These models have relied on a combination of econometric and univariate techniques to maximize the accuracy of the resulting forecast.

Mr. Nunes has also been involved in the evaluation of power supply options, including joint power supply arrangements, and the negotiation of power supply contracts. This work has incorporated the simulation of the utilities' power supply arrangements and typically utilizes scenario planning and probabilistic analytical techniques to assess the range of potential results and clients' risk exposure.

Financial Planning and Analysis

- Utility Cost of Service
- Rate Design
- Stranded Cost Analysis
- Asset Valuation

Mr. Nunes has been involved in numerous analyses and reports related to energy sector clients' cost of service, wholesale and retail rates, and annual budgets. His responsibilities have included the projection of utility cost of service and associated wholesale and retail electric rates, including the investigation of alternative financing options, rate stabilization strategies, and rate structures. In addition, Mr. Nunes has been involved in the preparation of Consulting Engineer's reports for Official Statements and annual reports as required by bond resolutions.

Mr. Nunes has been involved in various studies to assist clients in preparing for increased competition in power supply. In particular, he has been involved in the development of stranded cost estimates for various utilities and associated impact on competitive rates of various recovery methodologies. Mr. Nunes has also been involved in the development of a computer model to assist municipal clients in analyzing the benefits of the ownership of their distribution system and the impact of deregulation on their system and customers. In addition, Mr. Nunes has assisted clients in the development of pricing and service strategies aimed at customer retention and securing long-term retail power supply contracts.

Econometric Analysis

Mr. Nunes has been responsible for numerous modeling assignments for clients in the energy and solid waste industries. These models have primarily involved the use of econometric analysis to establish the influence of various factors on important decision variables. In the energy sector, this work has included development of an econometric model of the United States natural gas market, the estimation of power plant output at critical temperatures and pressures, and estimates of the future demand for primary and after-market power plant equipment based on electricity demand, the size of the fleet, and operating characteristics.

In the solid waste industry, Mr. Nunes was responsible for the gathering, management, and analysis of waste composition and building characteristics data to determine the factors that influence recycling success. This was part of a larger project to assist the strategic planning efforts of a major city in the Northeast United States. Mr. Nunes was also involved in the development of a solid waste characterization model that estimates the composition of a community's solid waste based on the characteristics of the community. The estimate relies on a series of regression models that take into account economic and demographic variables and recycling penetration. Mr. Nunes also developed econometric forecasts of the amount of solid waste generation by county in Pennsylvania for the Pennsylvania Department of Environmental Protection.

Employment

History:	1993-Present	R. W. Beck, Inc.
Education:	M.A.	Applied Economics, University of Central Florida
	B.S.	Business Administration/Economics, University of Central Florida

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080253-EM EXHIBIT 8
COMPANY FL Municipal Power Agency (Direct)
WITNESS Myron R. Rollins (MRR-1)
DATE 08-04-08

RESUME OF

MYRON R. ROLLINS

Black & Veatch

Director

Project Management; Integrated Resource Planning; Permitting and Licensing; Feasibility Studies and Project Development

Education
Bachelors, Electrical, University of Missouri at Columbia, 1974

Professional Registration
Engineer (PE), Missouri, 1982

Total Years Experience
32

Joined B&V
1976

Professional Associations
MoKan American Nuclear Society – Past President
Institute of Electrical and Electronics Engineers – Senior Member

Language Capabilities
English

Mr. Rollins is a Director in Enterprise Management Solutions. He is responsible for management of system planning and feasibility studies encompassing the areas of integrated resource planning, load forecasting, generation planning, cogeneration, site selection, and other special studies.

Mr. Rollins specializes in generation planning and project development. He is responsible for numerous power supply studies incorporating integrated planning techniques. Mr. Rollins was responsible for the development of Black & Veatch's POWRPRO chronological production costing program and POWROPT optimal generation expansion program. He is also responsible for power market analysis and project feasibility studies. Mr. Rollins extends his expertise in generation system planning to the area of need for power certification of power plants.

Mr. Rollins has broad expertise in planning and project development that enables him to assist clients in the development of expansion plans and specific projects in a realistic manner that incorporates the required balance between engineering and cost considerations as well as sociopolitical and licensing considerations. With this experience, Mr. Rollins has successfully helped utility and developer clients add value to their systems and projects throughout his career.

Mr. Rollins has presented expert testimony on several occasions before the Alaska, Florida, Indiana and Missouri Public Service Commissions, and has published numerous papers on strategic planning and cogeneration. He is past chairman of the Mo-Kan section of the American Nuclear Society and a senior member of IEEE.

Representative Project Experience

Need for Power Certification, Orlando Utilities Commission, Florida 2005-2006
Project Manager. Managed the preparation of a Need for Power Application for Orlando Utilities Commission's Stanton Energy Center Unit B. Stanton B is a proposed IGCC unit to be constructed at Stanton Energy Center in Orlando, Florida. The application was submitted to the Florida Public Service Commission under the Electrical Power Plant Siting Act. The Need for Power Application evaluated Stanton B against

other self-build alternatives and demand-side management alternatives. The Florida Public Service Commission unanimously approved the need for Stanton B.

Need for Power Certification, Florida Municipal Power Agency, Florida
2005
Project Manager. Managed the preparation of a Need for Power Application for Florida Municipal Power Agency's (FMPA's) Treasure Coast Energy Center (TCEC) Unit 1. TCEC Unit 1 is a proposed 1x1 F class combined cycle unit to be constructed on a greenfield site in Ft. Pierce, Florida. The application that was submitted to the Florida Public Service Commission under the Florida Electrical Power Plant Siting Act. The Need for Power Application evaluated TCEC Unit 1 against other self-build alternatives, purchase power from a request for proposals (RFP) process, and demand-side management alternatives. The Florida Public Service Commission unanimously approved the need for TCEC Unit 1.

Integrated Resource Plan, City of Tallahassee, Florida
2005-2006
Project Manager. Managing an integrated resource plan (IRP) for the City of Tallahassee. The IRP involves extensive evaluation of gas and coal fueled alternatives. More than 140 demand-side management (DSM) measures were evaluated. The IRP includes extensive evaluation of the impacts from the Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR). Biomass generation was evaluated as part of the IRP. Extensive probabilistic risk analysis was also conducted.

Integrated Resource Plan, JEA, Florida
2005-2006
Project Manager. Managing an integrated resource plan (IRP) in conjunction with JEA. The IRP involves extensive evaluation of gas and coal fueled alternatives including the development of site-specific estimates. Requirements for the Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR) were included in determining air quality control additions necessary for existing units. Demand-side management (DSM) evaluation made use of previous work conducted by Black & Veatch as part of JEA's Conservation Goal Docket before the Florida Public Service Commission.

Integrated Resource Plan Review, City of Lakeland, Florida
2005
Project Manager. Managed the review of the development of the City of Lakeland's integrated resource plan (IRP). The review encompasses all aspects of the IRP including load forecast, fuel forecast, development of supply side alternatives, life extension, and expansion planning. In

addition, Black & Veatch evaluated demand-side management alternatives for the City of Lakeland.

Expert Testimony, Indiana Municipal Power Agency, Indiana
2004
Project Manager. Presented expert testimony before the Indiana Utility Regulatory Commission for issuance of a Certificate of Public Convenience and Necessity. The testimony covered the technical and economic feasibility for three coal generating unit projects in which the Indiana Municipal Power Agency planned to participate.

St. Johns River Power Park Annual Report, JEA, Florida
2004
Project Manager. Managed preparation of the annual report on the operation and maintenance of St. Johns River Power Park consisting of two 675 MW pulverized coal units burning a mix of coal and petroleum coke. The units are jointly owned by Florida Power & Light Company and JEA. The annual operation and maintenance report is required to be submitted to the bond trustee under JEA's bond covenants.

Ten Year Site Plan, Orlando Utilities Commission, Florida
2004
Project Manager. Managed the preparation of the Ten Year Site Plan for Orlando Utilities Commission as required by the Florida Public Service Commission. The Ten Year Site Plan is an integrated resource expansion plan for the utility including load forecast, fuel price forecast, demand side management, and generation expansion.

Stock Island Combustion Turbine Unit 4 Development and Licensing, Florida Municipal Power Agency, Florida
2004
Project Manager. Managed development of the project description, the conceptual design, the development of lease and operating agreements, and permitting and licensing of a LM6000 simple cycle combustion turbine located at Key West, Florida. In addition, studies of the method of project execution, either EPC or traditional design and construction management, were developed along with a detailed schedule and cost estimate.

Combined Cycle Site Selection Study, Florida Municipal Power Agency, Florida
2004
Project Manager. Managed the site selection study for a 1x1 F class combined cycle for Florida Municipal Power Agency (FMPA). The site selection study initially evaluated four FMPA member generation sites. From those four sites, two were selected for detailed evaluation. The site selection study evaluated fatal flaws and permitting requirements, natural gas supply, water supply, wastewater disposal, and transmission

interconnection requirements. The study evaluated construction and operating costs differences between the two sites. The study also evaluated the ability to deliver power to the East system and the associated economic impacts of wheeling costs to get power to the East system. The study recommended selection of a site in St. Lucie County. Final permitting is currently under way for construction of the unit.

Independent Assessment, Edwards & Angell, Florida
2003
Project Manager. Managed an independent assessment of the current state and cost to complete of a partially completed combined cycle repowering project in Lake Worth, Florida for Edwards & Angell, the City of Lake Worth's bond attorney. The study involved developing an estimate to complete the project as a simple cycle combustion turbine and providing consultation on the development of a new natural gas transportation agreement and a memorandum of understanding between the existing owner, AES, and the new purchaser of the project, Florida Municipal Power Agency. The assignment also involved review and advise on numerous other project agreements.

Cane Island 4 Feasibility Study, Florida Municipal Power Agency, Florida
2002
Project Manager. Managed a feasibility study for the installation of a 1 x 1 F class combined cycle at the existing Cane Island Power Park. The study addressed site arrangement, the availability of cooling water, and the disposal of wastewater.

Cane Island 4 In-Service Capital Cost Estimate ($000)	
Item	
Combustion Turbine/Steam Turbine	48,400
EPC	246,900
Contingency	25,000
Owner's Costs	69,500
Total Project Costs	389,800
Interest During Construction	31,800
Total Installed Capital Cost	421,600

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080253-EM EXHIBIT 9
COMPANY FL Municipal Power Agency (Direct)
WITNESS Myron R. Rollins (MRR-2)
DATE 08-04-08

Estimated 1x1 F Class Combined Cycle Performance		
Performance Point	Unit Output (kW)	Unit Heat Rate (Btu/kWh, HHV)
Winter (19° F and 58% relative humidity) (Full Load)	329,800	7,435
Summer (102° F and 33% relative humidity) (Full Load)	299,600	7,445
Average (73° F and 80% relative humidity) (Full Load with Duct Firing)	307,200	7,420
Average (73° F and 80% relative humidity) (Full Load without Duct Firing)	246,990	6,969
Average (73° F and 80% relative humidity) (75% Load)	192,110	7,289
Average (73° F and 80% relative humidity) (50% Load)	140,990	7,923

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080253-EM **EXHIBIT** 10
COMPANY FL Municipal Power Agency (Direct)
WITNESS Myron R. Rollins (MRR-3)
DATE 08-04-04

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080253-EM EXHIBIT 11
COMPANY FL Municipal Power Agency (Direct)
WITNESS Jason L. Wolfe (JLW-1)
DATE 08-04-08

Jason Wolfe

University of Central Florida
B.S. in Business Administration
(concentration in finance)
Minor in Political Science

KEY EXPERTISE

- Risk Management and Risk Analysis
- Regulatory Filing Support
- Litigation Support Services
- Wholesale Power Market Studies
- Wholesale Power Cost Projections
- Financial Planning and Analysis
- Engineering Reports

Mr. Wolfe is a Senior Analyst with R. W. Beck, Inc. Since joining the company in 2000, he has provided a wide range of consulting services, including quantitative risk assessments, wholesale power market studies, wholesale power cost projections, and financial analyses. Additionally, he has provided support in the development of annual engineering reports and in legal and regulatory proceedings.

Prior to joining R. W. Beck, Mr. Wolfe worked for one year as a financial analyst in the Combustion Turbine Engineering Department of Siemens Westinghouse Power Corporation.

Relevant Expertise

Risk Management and Risk Analysis

Mr. Wolfe has participated in several quantitative risk analysis and portfolio evaluation studies for clients throughout the United States. These studies have generally involved the evaluation of various power supply alternatives.

Mr. Wolfe participated in a project for CPS Energy that included a quantitative risk analysis process to evaluate power supply decisions including potential participation in future nuclear units, and other power supply technology options that included pulverized coal units, integrated coal gasification combined-cycle (IGCC) and combined-cycle (CC) gas turbines plants. The quantitative risk analysis involved projections of annual bus bar costs for each generation alternative considered (nuclear, coal, IGCC, and CC) and projections of total revenue requirements under alternative generation plans and associated "risk profiles".

Mr. Wolfe provided analytical assistance for an assessment of the estimated relative risks facing Florida Municipal Power Agency (FMPA) with respect to three potential power supply alternatives. The portfolio evaluation and risk analysis characterized and quantified the relative market risks between FMPA's base case power supply portfolio and two alternative power supply portfolios. The analysis was focused on assessing market price risks (e.g., risks from market price volatility, fuel price volatility, load volume risk, etc.). The risk analysis provided additional insight to the robustness of various expansion plans with respect to changes in fundamental market conditions.

Mr. Wolfe assisted in the development of custom risk analysis tools and methods for Seminole Electric Cooperative to enhance their power supply planning process. The work was initially performed to help Seminole consider two base load power supply options. The risk tools develop projections of Seminole's total Member power costs and associated confidence intervals under various power supply alternatives. The models were designed to be used by the Seminole staff for future power supply analysis.

R·W·BECK

Regulatory Filing Support

Mr. Wolfe has developed or provided analytical support for several state or territory regulatory filings. Mr. Wolfe has provided support in the preparation of exhibits and supporting work papers for new generating resource need determination filings. Mr. Wolfe managed the development of FMPA's Ten-Year Site Plan for two years. Mr. Wolfe also assisted the Virgin Islands Water and Power Authority with several filings to the Virgin Islands Public Services Commission of the Authority's Levelized Energy Adjustment Clause.

Litigation Support Services

Mr. Wolfe has provided analytical support for several legal cases prosecuted before various state commissions and FERC. He has provided support in the preparation of exhibits and supporting work papers and assisted with discovery requests and interrogatories. These analyses have included studies on the historical operating performance of and forecasted annual decommissioning expenses for nuclear power plants, as well as the review of historical zonal and nodal LMP data in the northeastern United States.

Wholesale Power Market Studies

Mr. Wolfe has participated in deregulated wholesale power market studies throughout the Eastern Interconnect to develop regional and zonal market price projections for utilities, developers, lending institutions, and end-use customers. Mr. Wolfe has developed analyses to support the development of testimony relating to these studies and was involved in the largest merchant project financing to date in North America.

Mr. Wolfe has developed comprehensive dispatch simulation models that span multiple NERC regions and incorporate detailed information regarding generating resource operating characteristics and transmission interconnections and constraints. Mr. Wolfe has performed extensive research on new generating projects throughout much of the eastern United States and has developed spreadsheet tools to assist with modeling generating resource expansion planning.

Wholesale Power Cost Projections

Mr. Wolfe has performed projections of future wholesale electric power costs for joint action agencies and other clients in the southeastern United States. For the FMPA, Mr. Wolfe has developed models to project both short-term and long-term costs and rates. For example, FMPA's Total Cost Model (TCM) integrates output from production simulation models with other cost projections and forecasted demand and energy requirements to produce 20-year projections of FMPA's total revenue requirements and average rates to Members. FMPA utilizes the TCM for many purposes, including the evaluation of future power supply alternatives.

Financial Planning and Analysis

Mr. Wolfe has provided analytical support for new money bond financings, bond refundings, arbitrage rebate requirement compliance analyses, economic feasibility studies, and risk analyses. For example, Mr. Wolfe was involved in the preparation of Initial Project Feasibility Studies for American Municipal Power–Ohio (AMP-Ohio) related to AMP-Ohio's proposed 960 MW, coal-fired, American Municipal Power Generating Station (AMPGS), and 23.26 percent undivided ownership interest in the 1,584 MW, coal-fired, Prairie State Energy Campus. The purpose of the Project Feasibility Studies was to (1)

address the technical, operational, and financial implications and risks of the Project, and (2) provide a comprehensive examination of the Project.

Engineering Reports

Mr. Wolfe has been involved in the preparation of annual engineering reports for municipal joint-action agencies and municipal utility systems as required by the bond resolutions of the agency or utility. These reports have included discussions regarding operation and management issues, sufficiency of rates, and requirements for future bulk power supply.

Specialized Software Knowledge

EPRI *Energy Book System*

Ventyx *Market Power*

Ventyx *PROMOD*

Ventyx *Strategist*

Oracle *Crystal Ball*

Nicholas P. Guarriello, P.E.

New York University
Master of Business Administration

Polytechnic University
B.S. in Electrical Engineering
Registered Professional Engineer

KEY EXPERTISE

- Contract Analyses and Negotiations
- Power Supply Planning
- Financings
- Expert Testimony and Litigation Support
- Joint Action Agencies
- Retail Rate Studies
- Annual and Biennial Reports
- Independent Power Producers and Cogeneration
- Appraisals
- Environmental

Mr. Guarriello joined R. W. Beck in 1977 and is currently serving as Principal and Immediate Past President/CEO. From 1998 through November 1, 2005, Mr. Guarriello was the Firm's President and CEO. Since joining the Firm, he has served as Project Manager or Principal-in-Charge for numerous projects involving electric, gas, solid waste, water, and wastewater utility systems. His experience includes: litigation support and expert testimony; financings; appraisals; retail rate studies; wholesale rate work; power supply planning; consulting engineer's reports for bond financing; contract analyses and negotiations including those related to joint ownership agreements; and annual and biennial reports required by bond resolutions. Mr. Guarriello has also directed or participated in providing a wide range of consulting services to several large joint action agencies.

Mr. Guarriello has had significant experience in strategic and long-term planning for his electric utility clients. He has been involved in several internal task forces and external presentations addressing the competitive and restructuring issues facing the utility industry in the United States including transmission access, deregulation, technological improvements, and retail wheeling.

Mr. Guarriello has been involved in providing expert assistance or testimony regarding open access transmission filings in light of a changing utility environment and increased competition.

On behalf of a 29 member joint action agency in Florida, he assisted in the filing and negotiations regarding the agency's request for network transmission service under Sections 211 and 212 of the Federal Power Act. Mr. Guarriello participated in the development of the rates, terms, and conditions for network transmission filed before FERC. This project represented the first ever approval of network transmission under Section 211 by FERC.

In addition, he has made several presentations regarding the renewed interest in coal generation and the future of the electric power industry. He stays abreast on utility trends impacting the industry, and over the years, has spoken at several executive forums.

Relevant Expertise

Contract Analyses and Negotiations

- Joint Ownership Agreements
- Energy Purchase and Sales Agreements
- Transmission Arrangements
- Contract Arbitration

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080253-EM **EXHIBIT** 12
COMPANY FL Municipal Power Agency (Direct)
WITNESS Nicholas P. Guarriello, P.E. (NPG-1)
DATE 08-04-08

RW BECK

Mr. Guarriello has extensive experience in negotiating and evaluating energy purchase and sales agreements involving nuclear, coal, oil, gas, waste-to-energy and cogeneration projects. He has also been involved with developing transmission and interconnection arrangements for electric systems and qualifying facilities. Clients for whom he has negotiated contracts and settlements include the Florida Municipal Power Agency, the East Florida Municipal Group, Fort Pierce Utilities Authority, the Utility Board of the City of Key West, the City of Clarksdale, Mississippi and a large private commercial improvement district. Contractual agreements have involved short and long term power arrangements, contracts associated with the operation of jointly-owned generating facilities, wholesale power agreements and contracts dealing with unit power purchases.

Prior to joining R. W. Beck, Mr. Guarriello's experience included the negotiation and administration of special contracts associated with the operation of jointly owned generating facilities. He assisted in the preparation of testimony in rate cases and arbitration's involving these special contracts.

Power Supply Planning

- Load Forecasts
- Economic Feasibility Studies

Mr. Guarriello has directed and participated in numerous power supply studies for both municipalities and joint action agencies. Ongoing power supply studies have been provided for Florida clients including the Florida Municipal Power Agency, the Utility Board of the City of Key West, the Cities of Vero Beach and Jacksonville Beach, the Fort Pierce Utilities Authority, FMPA and a large private commercial improvement district. These studies have included load forecasting, alternative power supply resource analyses, economic and financial feasibility studies, and risk analyses. For the Utility Board of the City of Key West, Mr. Guarriello served as Project Manager for a power supply study evaluating twelve different power generation expansion alternatives. After screening down to five alternatives, the options were analyzed with regard to the amount of projected capacity deficiencies, the capacity factors at which the units would be operated, potential power purchases over time, existing resources review, sensitivity analyses, and the reliability of supply. Mr. Guarriello was also co-author for a paper on the analysis of generating reserve requirements for interconnected power systems, and participated in the development of a capacity reserve analysis program. Prior to joining R. W. Beck, Mr. Guarriello worked for a major mid-Atlantic utility in the area of bulk power supply planning. His responsibilities included the analysis of systems load, the development of long-range load forecasts, the optimization of hydro-fossil-nuclear generating capacity data for hydroelectric project license applications and proceedings, environmental impact statements and plant siting studies.

Financings

- Consulting Engineer's Reports
- Contract Documents and Bond Resolutions

Mr. Guarriello has extensive experience in the preparation of consulting engineer's reports which are included in official statements for major tax exempt revenue bond financings for utility systems. Mr. Guarriello has been involved in over $2 billion in bond financings. He has worked with bond counsels, attorneys and underwriters on the development of bond resolutions and contract documents. Clients for whom Mr. Guarriello has provided ongoing bond financing support include the Florida Municipal Power Agency, the cities of Tallahassee, Bushnell and Jacksonville Beach, the Utility Board of the City of Key West, and the Fort Pierce Utilities Authority. Serving as Project Manager, he participated in the financings of major tax-exempt projects including the St. Lucie and Stanton projects for FMPA.

For the Fort Pierce Utilities Authority, he has been involved with financings for the electric, water, sewer and gas systems.

Expert Testimony and Litigation Support

- Wholesale Rates
- Transmission Access
- Interchange Agreements

In the past, Mr. Guarriello has submitted testimony, and testified before the Florida Public Service Commission in several proceedings relating to generic hearings on peak load pricing and declining block rates, certification of need hearings for new coal-fired units to be built in Florida, and the Commission's investigation to determine the need for an additional 500 kilovolt transmission line interconnection between Florida and the Southern Company System. He has testified in support of wholesale rates and negotiated settlements for wholesale rate cases for the Twelve Cities Public Power Committee, which were the all-requirements cities on the Florida Power Corporation System. Mr. Guarriello has also testified for the East Florida Municipal Group which includes the generating and all requirements cities of the Florida Power and Light System. He has provided litigation support with respect to transmission and interchange agreements.

Joint Action Agencies

- Annual Engineer's Reports
- Bond Financing
- Power Supply Studies
- Contractual Negotiations
- Litigation Support and Expert Testimony

Mr. Guarriello has had many years of experience providing services for joint action agencies in the Southeastern United States. He played a key role in the formation of the Florida Municipal Power Agency (FMPA) and the Municipal Energy Agency of Mississippi (MEAM), having developed, together with bond counsel, financial advisors and agency staff, the contractually complex joint action agency agreements. FMPA was created in 1978 to allow its 28 member utility systems to join together for joint financing, constructing, managing, operating, utilizing and owning projects. Mr. Guarriello has served as Project Manager and Principal-in-Charge for numerous power supply studies, bond financings, and contractual analyses and negotiations including those relating to joint ownership agreements, and litigation support services for FMPA and MEAM.

Retail Rate Studies

- Electric, Gas, Water and Sewer Systems

Mr. Guarriello has performed electric, sewer, water and gas retail rate studies for many of the Firm's Florida municipal clients. He has directed or participated in rate studies that have included revenue requirement forecasts, cost of service, user fees, impact fees, rate design and long term load forecasts. He has also directed rates studies in which cross subsidization between classes has been analyzed. As Principal-in-Charge or Project Manager he has provided rate studies for the Utility Board of the City of Key West, the Fort Pierce Utilities Authority, the cities of Homestead, Bushnell, Vero Beach, Tallahassee, and New Smyrna Beach, and a large private commercial improvement district.

For proceedings before the Florida Public Service Commission, Mr. Guarriello developed a tutorial on how municipalities in Florida develop retail rates. The tutorial outlined how rates were developed and structured.

Annual and Biennial Reports

- Operations and Maintenance Review
- Status of Operating Budget

Mr. Guarriello has served as Project Manager or Principal-in-Charge for the preparation of annual and biennial reports for over 15 years. For FMPA he oversaw the production of the Annual Engineer's Report for the St. Lucie and Stanton projects, which included a report on the status of the current annual budget and construction fund, and a report on its construction, operation and maintenance, and renewals and replacements. The project included the review of capital expenditures and operating budgets, comparing budgeted versus actual revenues and construction costs. Also for FMPA, Mr. Guarriello acted as Principal-in-Charge for the Annual Engineering Report for the Tri-City project. The participant cities included Fort Pierce Utilities Authority, the City of Homestead and the Utility Board of the City of Key West, Florida. As Project Manager for the Annual Report conducted for a large private commercial improvement district, Mr. Guarriello reviewed seven utility systems with regard to: the management of the properties; operation and maintenance; the status of the operating budget and construction fund; and the sufficiency of rates and charges for services. The improvement district's systems included the electric, water, wastewater, gas, solid waste, hot water, and chilled water systems. Mr. Guarriello has also been in charge of the Annual and Biennial reports for the Cities of Tallahassee, Bushnell and the Utilities Commission of New Smyrna Beach, and the Utility Board of the City of Key West.

Independent Power Producers and Cogeneration

- Contract Negotiations
- Bid Process Evaluation and Proposal Analysis

Mr. Guarriello has extensive experience in negotiating and evaluating contracts for cogeneration projects for municipal utilities. For the Orlando Utilities Commission he served as Project Manager, reviewing and evaluating the bid process for independent power producers (IPP's), and providing financial support in analyzing the proposals. Acting as Principal-in-Charge for services provided to the City of Tallahassee, he reviewed the economic impact on the City's electric and gas systems operations of the installation of a potential cogeneration project by one of the City's largest customers, Florida State University. The tasks for the project included describing the proposed arrangements, preparing computer generation dispatch models, preparing economic analyses and comparisons, and preparing projected operating results for both the electric and gas systems.

Appraisals

- Utility Valuation
- Economic Studies

Mr. Guarriello has reviewed appraisals of utility property, including water, wastewater and electric systems. These appraisals have involved various valuation methodologies, including discounted cash flow analyses, direct capitalization's of income, and Original Cost Less Depreciation (OCLD) and Reproduction Cost New Less Depreciation (RCNLD) studies. The results of these studies have been used to establish the fair market value of property to be sold or acquired by clients in negotiated sales or

through condemnation. He has also performed economic studies to determine the value and feasibility of proposed capital projects.

Environmental

- Clean Air Act Amendment

Mr. Guarriello has experience in working with our clients relating to the understanding of the Clean Air Act Amendment of 1990 and its applicability to electric utilities. Mr. Guarriello, as Principal-in-Charge, has been responsible for providing consulting services to our clients including (i) conducting seminars on the Clean Air Act of 1990 including meeting requirements for Continuous Emissions Monitoring Equipment (CEMS) for affected sources; (ii) reviewing data tabulated in the National Allowance Data Base, Version 1.0 and Version 2.0 as published by the Energy Information Administration (EIA) and preparing letters to the EIA with corrections to the data base as necessary; (iii) reviewing legislation to ensure all bonus allowances have been identified and all current options for allowances evaluated; (iv) preparing letters to EPA requesting the baseline years and corresponding fuel consumption for use in calculating the allowance allocation for each unit; (v) calculating the amount of emissions reductions that will be required by affected generating units to meet the limitations specified under the legislation; (vi) identifying options available for compliance with the legislation, such as: purchasing additional allowances, reducing the operation of affected units, obtaining allowances from other units, installing scrubbers, and using lower sulfur fuel; and (vii) investigating the possibility of electing units to be covered by the legislation which are not automatically affected (i.e. units of 25 MW or less or simple cycle combustion turbines) and evaluating the number of allowances that would be obtained.

Published Articles

"Roles of Fuels/Technology in Future US Power Demand," Published by Wiley Periodicals in *Natural Gas & Electricity*, May, 2006

"Class of 2005," Published in *World-Generation*, Dec./Jan., 2005.

"The Coal Rush," Published in *World-Generation*, Sept./Oct., 2004.

"R. W. Beck Leverages Energy Experience into Water/Wastewater Markets," Published in the *Environmental Business Journal*, Volume XIV, Number 1-2, 2002

Presentations

Coal-Based Partnerships – An Economic Overview of "The Coal Rush" at Elcon, Washington, D.C., Oct., 2006

"The Coal Rush Revisited," Presentation at *COAL-GEN 2006*, Cincinnati, Ohio, Aug., 2006

"How Electric Utilities Will Meet the Demand for Power in the U.S., Including What Role Fuels/Technology Will Play," Keynote presentation at IPED Coal Conference, Naples, Fla., Jan., 2006

"Vision of the Future," Keynote presentation at RMEL Fall Conference, Jackson, Wyo., Sept., 2005

"The Coal Rush: An Economic Overview of the Renewed Interest in the Power Industry's 'Old Stand-by,'" Presented at the Cinergy Anniversary Conference, *"Coal 2020,* Cincinnati, Ohio, Oct., 2004

"The Coal Rush: An Economic Overview of the Renewed Interest in the Power Industry's 'Old Stand-by,'" Presented at the IPED's *"New Coal-Fired Generation: A Practical Course in Joint Ownership and the Coal Market"* Conference, Washington, D.C., Dec., 2004

"The Coal Rush: An Economic Overview of the Power Industry's 'Old Stand-by,'" Presented at the Aspen Summit, Aspen, Colo., July, 2004

Affiliations

Board Member of Keystone Energy

Delegate of Aspen Institute

Utility System Planning, Production Costing, Economic Analysis, and Demand-Side Management

Resume of Bradley E. Kushner Black & Veatch

Mr. Kushner is responsible for production costing associated with utility system expansion planning, as well as feasibility studies and economic analysis, and demand-side management evaluation. He has also been involved in the issuance and evaluation of requests for proposals (RFPs) and portfolio evaluations. Mr. Kushner has also presented expert testimony and prepared other experts for testimony related to determination of need proceedings, and has also testified under cross examination by intervening parties.

Education
Bachelors, Mechanical Engineering, University of Missouri at Columbia, 2000

Total Years Experience
8

Joined Black & Veatch
2000

Representative Project Experience

Valuation of Generating Unit Portfolio; Confidential Client
2007 - Present
Study Manager. Oversee modeling and evaluation of purchase power contracts related to Client's portfolio of generation assets throughout North America. The purchase power contracts are being modeled to assess a monetary value to be used as guidance for valuation of overall generation portfolio. The portfolio of assets and associated purchase power contracts includes more than 50 models. Mr. Kushner is involved in the modeling of the contracts as well as quality assurance/quality control related to the entire portfolio prior to delivering evaluations to Client.

Characterization and Selection of Nuclear Generating Technologies; AmerenUE; Missouri
2007 - Present
Project Analysis Engineer. Provide assistance in characterizing and screening of various nuclear generating technologies for consideration by AmerenUE. The nuclear technology selected for further evaluation will be evaluated as part of Client's Integrated Resource Plan (IRP) study. The characterization included consideration of provisions of the Energy Policy Act of 2005 related to new qualifying nuclear plant capacity as well as relative comparisons of competing nuclear generating technologies. Client deliverables included two separate presentations to AmerenUE's Stakeholders.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080253-EM **EXHIBIT** 13
COMPANY FL Municipal Power Agency (Direct)
WITNESS Bradley E. Kushner (BEK-1)
DATE 08-04-08

Supply-Side Technologies Characterization; Tampa Electric Company; Tampa, Florida
2007
Study Manager. Provide cost and performance estimates for various renewable, conventional, and other generating technologies for client consideration in support of their determination of need filing. Technologies considered approximately 20 renewable technologies (including biomass, biogas, waste-to-energy, wind, solar, geothermal, hydroelectric, and ocean energy), 6 conventional technologies (including simple and combined cycles), and 2 emerging technologies (including nuclear). Also considered advanced, energy storage, and distributed generation technologies.

Education
Bachelors, Mechanical Engineering, University of Missouri at Columbia, 2000

Total Years Experience
8

Joined Black & Veatch
2000

Power Supply Study; Western Farmers Electric Cooperative; Anadarko, Oklahoma
2006 - Present
Study Manager. Provide production costing, economic analysis, and various other support to facilitate completion of the Western Farmers Electric Cooperative (WFEC) Power Supply Study. The WFEC Power Supply Study is an update to previous capacity planning studies which evaluates the economics of various supply-side alternatives to satisfy forecast capacity requirements.

Integrated Resource Plan; Village of Rockville Centre, New York
2006 - Present
Study Manager. Analysis related to and preparation of the Village of Rockville Centre (RVC) Integrated Resource Plan (IRP). The IRP will include consideration of RVC's existing generating system and strategic planning to satisfy forecasted system requirements. The strategic planning process includes consideration of conventional supply-side options, interaction with the purchase power market, demand-side management measures, renewable supply-side alternatives, and possible future environmental impacts.

Taylor Energy Center Need for Power Application; Various Clients, Florida
2005 - 2007
Study Manager. Provide production costing, economic analysis, and various other support to facilitate completion and filing of the Taylor Energy Center (TEC) Need for Power Application (NFP). Also includes preparation of testimony related to the project to the Florida Public Service Commission (FPSC). The NFP provides a determination of the most cost-effective capacity addition to satisfy forecasted capacity

requirements for the four separate utilities participating in the project. The analysis considered self-build and purchase power alternatives.

Integrated Resource Plan; City of Tallahassee; Tallahassee, Florida
2004 - 2007
Study Manager. Analysis related to and preparation of the City of Tallahassee's (the City's) Integrated Resource Plan (IRP). The IRP will include consideration of the City's existing generating system and strategic planning to satisfy forecasted system requirements. The strategic planning process includes consideration of conventional supply-side options, demand-side management measures, renewable supply-side alternatives, and possible future environmental impacts.

Integrated Resource Plan; Brazos Electric Power Cooperative, Texas
2005 - 2006
Project Analysis Engineer. Provide assistance to Brazos Electric Power Cooperative (Brazos) in developing their Integrated Resource Plan (IRP). Includes drafting a request for power supply proposals (RFP), analysis of responses to the RFP, review of Brazos production costing analysis, and documentation of final report. The IRP will provide strategic direction to Brazos, which is currently experiencing and is forecast to continue to experience robust system growth.

Stanton Energy Center Unit B Need for Power Application; Orlando Utilities Commission; Orlando, Florida
2005 - 2006
Study Manager. Provided production costing, economic analysis, and various other support to facilitate completion and filing of the Stanton Energy Center Unit B (Stanton B) Need for Power Application (NFP). Also included preparation of testimony related to the project to the Florida Public Service Commission (FPSC). The NFP provides a determination of the most cost-effective capacity addition to satisfy forecasted capacity requirements for the Orlando Utilities Commission. The FPSC approved the Stanton B NFP Application in May 2006, which represents the first coal-fired power plant approved in the State of Florida since 1991.

RFP Issuance and Evaluation; Western Farmers Electric Cooperative; Anadarko, Oklahoma
2002 - 2006
Project Analysis Engineer. Coordinated with Western Farmers Electric Cooperative (WFEC) to draft, issue, and evaluate a capacity solicitation (RFP) to secure forecast capacity requirements in most cost-effective and reliable manner. The RFP process was undertaken through coordination with Rural Utilities Services (RUS) in an effort to obtain low-cost RUS

project financing. Involved evaluation of numerous conventional as well as renewable technology proposals and culminated in the issuance of a short-list and presentation to WFEC Board of Directors.

Saint Johns River Power Park Annual Review; JEA; Jacksonville, Florida
2006
Engineering Manager. Preparation of annual report documenting the previous year's operations of the St. Johns River Power Park. Included a summary of the findings of field activities, staff interviews, observations, and document review associated with the Power Park.

Ten-Year Site Plan, FRCC Forms, EIA-860 and Annual Conservation Report Filings; Orlando Utilities Commission; Orlando, Florida
2006
Engineering Manager. Production costing and economic analysis necessary to complete the Orlando Utilities Commission 2006 Ten-Year Site Plan and submit to the Florida Public Service Commission (FPSC). Related to the Ten-Year Site Plan are the Florida Reliability Coordinating Council (FRCC) filings, which are submitted to FRCC via electronic database and forwarded to the Energy Information Administration (EIA) by FRCC. The EIA-860 collects data related to the specific utility's existing and planned generating units. The Annual Conservation Report is prepared and submitted to the FPSC in order to summarize the utility's conservation and demand-side management efforts.

RFP Issuance and Evaluation; City of Columbia, Water & Light Department; Columbia, Missouri
2005 - 2006
Study Manager. Coordinate with the City of Columbia, Water & Light Department (the City) to draft, issue, and evaluate a capacity solicitation (RFP) to secure forecast capacity requirements in most cost-effective and reliable manner. Involved evaluation of numerous conventional capacity options under consideration by the City, as well as options proposed by respondents to the RFP. Included continuous communication with City staff as well as presentations to the City's planning committee.

Treasure Coast Energy Center Need for Power Application; Florida Municipal Power Agency; Orlando, Florida
2004 - 2005
Project Analysis Engineer. Provided production costing, economic analysis, and various other support to facilitate completion and filing of the Florida Municipal Power Agency's (FMPA) Need for Power Application (NFP). Also provided testimony related to the project to the

Florida Public Service Commission (FPSC). The NFP provides a determination of the most cost-effective capacity addition to satisfy forecasted capacity requirements. The analysis performed for FMPA considered self-build and purchase power alternatives. The NFP Application was approved by the FPSC in July, 2005, representing a critical step in the permitting and licensing process in the State of Florida.

Stock Island Combustion Turbine Evaluation; Florida Municipal Power Agency; Orlando, Florida
2004 - 2005
Project Analysis Engineer. Perform production costing and economic analysis to determine the most cost-effective capacity additions to be located at the Stock Island site. The analysis considered two different generating units from specific manufacturers, who responded to FMPA's request for bids.

Generation Expansion Study; Oman
2005
Project Analysis Engineer. Performed production costing and economic analysis to determine the most cost-effective capacity additions to satisfy forecast capacity requirements in the Country of Oman. The analysis considered seven different generating technologies.

Integrated Resource Plan; Golden Valley Electric Association; Fairbanks, Alaska
2005
Project Analysis Engineer. Economic analysis in support of the Golden Valley Electric Association's (GVEA) Integrated Resource Plan (IRP). The IRP will provide GVEA with recommendations of capacity additions which will satisfy forecasted capacity requirements in the most cost-effective manner.

Ten-Year Site Plan and FRCC Forms; Florida Municipal Power Agency; Orlando, Florida
2005
Engineering Manager. Provided assistance and support to the Florida Municipal Power Agency (FMPA) related to its 2005 Ten-Year Site Plan and subsequent submission to the Florida Public Service Commission (FPSC). Related to the Ten-Year Site Plan are the Florida Reliability Coordinating Council (FRCC) filings, which are submitted to FRCC via electronic database and forwarded to the Energy Information Administration (EIA) by FRCC.

Saint Johns River Power Park Annual Review; JEA; Jacksonville, Florida
2005
Engineering Manager. Preparation of annual report documenting the previous year's operations of the St. Johns River Power Park. Included a summary of the findings of field activities, staff interviews, observations, and document review associated with the Power Park.

Ten-Year Site Plan, FRCC Forms, EIA-860 and Annual Conservation Report Filings; Orlando Utilities Commission; Orlando, Florida
2005
Engineering Manager. Production costing and economic analysis necessary to complete the Orlando Utilities Commission 2005 Ten-Year Site Plan and submit to the Florida Public Service Commission (FPSC). Related to the Ten-Year Site Plan are the Florida Reliability Coordinating Council (FRCC) filings, which are submitted to FRCC via electronic database and forwarded to the Energy Information Administration (EIA) by FRCC. The EIA-860 collects data related to the specific utility's existing and planned generating units. The Annual Conservation Report is prepared and submitted to the FPSC in order to summarize the utility's conservation and demand-side management efforts.

Due Diligence and Economic Analysis; Dairyland Power Cooperative; La Crosse, Wisconsin
2003-2005
Project Analysis Engineer. Performed due diligence review of the power supply planning efforts undertaken by Dairyland Power Cooperative (DPC). Included development of numerous capacity expansion plans and associated system production costing. Analysis was done in compliance with the requirements of the Rural Utilities Services (RUS) to potentially obtain low-cost RUS project financing. Also included was a presentation of the study's findings to the DPC Board of Directors. Following the issuance of a request for proposals (RFP) for capacity supplies, Black & Veatch was released to perform additional production costing and evaluations of the bids and self-build options was completed, with the results presented to DPC project personnel as well as RUS staff.

Numeric Conservation Goals Filing; JEA; Jacksonville, Florida
2004
Project Analysis Engineer. Analysis related to and preparation of the JEA 2004 Petition for Approval of Numeric Conservation Goals, as required by the Florida Public Service Commission (FPSC). The submittal included analysis of numerous demand-side management (DSM) measures to be

considered by JEA in order to determine their cost-effectiveness. The process is required to be completed by JEA every five years, culminating in the eventual determination by the FPSC of the conservation goals JEA must satisfy each year.

Numeric Conservation Goals Filing; Orlando Utilities Commission; Orlando, Florida
2004
Project Analysis Engineer. Analysis related to and preparation of the Orlando Utilities Commission (OUC) 2004 Petition for Approval of Numeric Conservation Goals, as required by the Florida Public Service Commission (FPSC). The submittal included analysis of numerous demand-side management (DSM) measures to be considered by OUC in order to determine their cost-effectiveness. The process is required to be completed by OUC every five years, culminating in the eventual determination by the FPSC of the conservation goals OUC must satisfy each year.

Site Selection Study; Florida Municipal Power Agency; Orlando, Florida
2004
Project Analysis Engineer. Coordination and preparation of a site selection study related to the potential construction of a new combined cycle unit to be installed by the Florida Municipal Power Agency.

Ten-Year Site Plan; Florida Municipal Power Agency; Orlando, Florida
2004
Engineering Manager. Provided assistance and support to the Florida Municipal Power Agency (FMPA) related to its 2004 Ten-Year Site Plan and subsequent submission to the Florida Public Service Commission (FPSC).

Saint Johns River Power Park Annual Review; JEA; Jacksonville, Florida
2004
Engineering Manager. Preparation of annual report documenting the previous year's operations of the St. Johns River Power Park. Included a summary of the findings of field activities, staff interviews, observations, and document review associated with the Power Park.

Ten-Year Site Plan, FRCC Forms, and Annual Conservation Report Filings; Orlando Utilities Commission; Orlando, Florida
2004
Engineering Manager. Production costing and economic analysis necessary to complete the Orlando Utilities Commission 2004 Ten-Year

Site Plan and submit to the Florida Public Service Commission (FPSC). Also included follow-up response to FPSC inquiries and preparation of presentation to FPSC staff. Related to the Ten-Year Site Plan are the Florida Reliability Coordinating Council (FRCC) filings, which are submitted to FRCC via electronic database and forwarded to the Energy Information Administration (EIA) by FRCC. Annual Conservation Report is prepared and submitted to the FPSC in order to summarize the utility's conservation and demand-side management efforts.

Due Diligence; City Utilities; Springfield, Missouri
2003
Project Analysis Engineer. Due diligence and economic analysis to determine the most cost-effective capacity additions to satisfy forecasted system requirements for City Utilities – Springfield. Two options were considered, consisting of constructing a second unit at an existing site and an independent developer's proposed construction of a unit at a new site.

Saint Johns River Power Park Annual Review; JEA; Jacksonville, Florida
2003
Engineering Manager. Preparation of annual report documenting the previous year's operations of the St. Johns River Power Park. Included a summary of the findings of field activities, staff interviews, observations, and document review associated with the Power Park.

Participation Agreement; Kissimmee Utility Authority; Orlando, Florida
2003
Engineering Manager. Development of a Participation Agreement between client (KUA) and another Florida utility governing ownership, construction, and operation of a new generating unit at a KUA site. Included meetings and coordination with clients and incorporation of various requirements to sufficiently complete the Agreement.

Ten-Year Site Plan, FRCC Forms, and Annual Conservation Report Filings; Orlando Utilities Commission; Orlando, Florida
2003
Engineering Manager. Production costing and economic analysis necessary to complete the Orlando Utilities Commission 2003 Ten-Year Site Plan and submit to the Florida Public Service Commission (FPSC). Also included follow-up response to FPSC inquiries and preparation of presentation to FPSC staff. Related to the Ten-Year Site Plan are the Florida Reliability Coordinating Council (FRCC) filings, which are submitted to FRCC via electronic database and forwarded to the Energy Information Administration (EIA) by FRCC. Annual Conservation Report

is prepared and submitted to the FPSC in order to summarize the utility's conservation and demand-side management efforts.

Capacity Planning Study; Western Farmers Electric Cooperative; Anadarko, Oklahoma
2001 - 2002
Project Analysis Engineer. Production costing and economic analysis to determine WFEC's most cost-effective expansion options to meet forecast capacity requirements. The capacity planning study was performed in support of the RFP issuance described above.

Feasibility Study; Kissimmee Utility Authority; Kissimmee, Florida
2002
Engineering Manager. Assisted in coordination and preparation of a preliminary study to evaluate the feasibility of constructing a new generating unit at an existing Kissimmee Utility Authority site.

Ten-Year Site Plan, FRCC Forms, and Annual Conservation Report Filings; Orlando Utilities Commission; Orlando, Florida
2002
Project Analysis Engineer. Production costing and economic analysis necessary to complete the Orlando Utilities Commission 2002 Ten-Year Site Plan and submit to the Florida Public Service Commission (FPSC). Also included follow-up response to FPSC inquiries and preparation of presentation to FPSC staff. Related to the Ten-Year Site Plan are the Florida Reliability Coordinating Council (FRCC) filings, which are submitted to FRCC via electronic database and forwarded to the Energy Information Administration (EIA) by FRCC. Annual Conservation Report is prepared and submitted to the FPSC in order to summarize the utility's conservation and demand-side management efforts.

Capacity Planning Study; Braintree Electric Light Department; Braintree, Massachusetts
2002
Project Analysis Engineer. Production costing and economic analysis to determine Braintree Electric Light Department's most cost-effective expansion options to meet forecast capacity requirements.

Integrated Resource Plan; City of Tallahassee; Tallahassee, Florida
2001-2002
Project Analysis Engineer. Assisted in completion of the City of Tallahassee's Integrated Resource Plan (IRP), including evaluation of the City's demand-side management program alternatives.

Table 1
Reference Case Price Projections
Forecast of Natural Gas and Fuel Oil Delivered to the
Florida Reliability Coordinating Council Boundary[1]

Year	Natural Gas (Nominal $/MBtu)[2]	Distillate Fuel Oil (Nominal $/MBtu)[3]	Residual Fuel Oil (Nominal $/MBtu)
2008	$7.76	$14.73	$8.46
2009	$7.33	$13.88	$7.95
2010	$7.17	$13.14	$7.59
2011	$6.79	$12.50	$7.32
2012	$6.78	$12.03	$7.08
2013	$6.77	$11.37	$7.04
2014	$6.96	$11.52	$6.99
2015	$7.04	$11.86	$7.26
2016	$7.41	$12.20	$7.41
2017	$7.83	$12.70	$7.74
2018	$8.02	$13.13	$7.97
2019	$8.22	$13.68	$8.39
2020	$8.52	$14.12	$8.69
2021	$8.66	$14.62	$9.06
2022	$9.02	$15.18	$9.45
2023	$9.37	$15.48	$9.56
2024	$9.83	$16.08	$10.00
2025	$10.04	$16.51	$10.27
2026	$10.32	$16.99	$10.66
2027	$10.70	$17.68	$10.97

[1] Based on data presented in Supplemental Table 69 to the AEO2007 Reference Case.
[2] Natural gas price projections do not include usage charges or firm or interruptible transportation charges within the state. These costs are accounted for in the economic analysis as discussed in Section 19.0 of Exhibit No. __[FMPA-1].
[3] Distillate fuel oil price projections reflect the "nonroad, locomotive, and marine" (NRLM) diesel regulation finalized in May 2004, which requires sulfur content for all NRLM diesel fuel produced by refiners to be reduced to 500 parts per million (ppm) starting in mid-2007. NRLM also establishes a new ultra-low sulfur diesel (ULSD) limit of 15 ppm for nonroad diesel by mid-2010.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080253-EM EXHIBIT 14
COMPANY FL Municipal Power Agency (Direct)
WITNESS Bradley E. Kushner (BEK-2)
DATE 08-04-03

Table 2
Reference Case Price Projections
Forecast of Low Sulfur Central Appalachian Coal Delivered to the Georgia/Florida Region[1]

Year	Low Sulfur Central Appalachian[2] (0.54 lb S/MBtu) (Nominal $/MBtu)
2008	$3.08
2009	$3.15
2010	$3.28
2011	$3.39
2012	$3.38
2013	$3.45
2014	$3.56
2015	$3.60
2016	$3.69
2017	$3.73
2018	$3.70
2019	$3.70
2020	$3.77
2021	$3.83
2022	$3.97
2023	$4.07
2024	$4.16
2025	$4.24
2026	$4.30
2027	$4.39

[1] Based on data received directly from the EIA.
[2] EIA price projections for Central Appalachian coal delivered to the Georgia/Florida region only extend through 2017, as the AEO2007 Reference Case assumes production from the Eastern Interior region, as well as imports, will contribute to the decline in Appalachia's share of the market east of the Mississippi. Beyond 2017, prices were developed on the basis of minemouth projections from the AEO2007 Reference Case and the assumption that transportation costs will remain constant in 2005 dollars.

Table 3
High Case Price Projections
Forecast of Natural Gas, Fuel Oil, and Central Appalachian Coal Delivered to the Florida Reliability Coordinating Council[1]

Year	Natural Gas (Nominal $/MBtu)[2]	Distillate Fuel Oil (Nominal $/MBtu)	Residual Fuel Oil (Nominal $/MBtu)	Low Sulfur Central Appalachian (0.54 lb S/MBtu) (Nominal $/MBtu)
2008	$8.14	$15.11	$8.82	$3.08
2009	$7.95	$15.03	$8.65	$3.17
2010	$7.88	$15.25	$8.72	$3.31
2011	$7.84	$15.38	$9.17	$3.43
2012	$7.59	$15.58	$9.86	$3.42
2013	$7.71	$15.86	$10.93	$3.49
2014	$7.94	$16.87	$11.62	$3.61
2015	$8.18	$17.81	$12.36	$3.65
2016	$8.64	$18.80	$12.96	$3.76
2017	$9.06	$19.59	$13.90	$3.81
2018	$9.13	$20.51	$14.74	$3.79
2019	$9.02	$20.99	$15.19	$3.81
2020	$9.56	$21.86	$15.95	$3.90
2021	$10.10	$22.13	$16.42	$3.99
2022	$10.47	$22.84	$16.78	$4.14
2023	$11.04	$23.23	$17.50	$4.25
2024	$11.38	$24.00	$18.02	$4.36
2025	$11.87	$24.44	$18.69	$4.44
2026	$12.53	$25.10	$19.38	$4.50
2027	$13.08	$25.81	$19.86	$4.57

[1] Based on data presented in Supplemental Table 69 (Reference Case), Table 12 (Reference Case), Table 12 (High Price Case), Table 13 (Reference Case), and Table 13 (High Price Case) in the AEO2007.
[2] Natural gas price projections do not include usage charges or intrastate firm or interruptible transportation charges. These costs are accounted for in the economic analysis as discussed in Section 19.0 of Exhibit No. ___[FMPA-1]

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080263-EM EXHIBIT 15
COMPANY FL Municipal Power Agency (Direct)
WITNESS Bradley E. Kushner (BEK-3)
DATE 08-04-08

Table 4
Low Case Price Projections
Forecast of Natural Gas, Fuel Oil, and Central Appalachian Coal Delivered to the Florida Reliability Coordinating Council[1]

Year	Natural Gas (Nominal $/MBtu)[2]	Distillate Fuel Oil (Nominal $/MBtu)	Residual Fuel Oil (Nominal $/MBtu)	Low Sulfur Central Appalachian (0.54 lb S/MBtu) (Nominal $/MBtu)
2008	$7.44	$13.85	$8.34	$3.07
2009	$6.80	$12.18	$7.39	$3.13
2010	$6.43	$10.60	$6.53	$3.25
2011	$6.11	$9.42	$5.86	$3.36
2012	$5.85	$8.30	$5.09	$3.34
2013	$5.69	$7.51	$5.17	$3.41
2014	$5.73	$7.19	$4.82	$3.50
2015	$5.72	$7.07	$4.68	$3.53
2016	$6.09	$7.15	$4.65	$3.62
2017	$6.29	$6.95	$4.85	$3.65
2018	$6.59	$7.02	$4.87	$3.62
2019	$6.90	$7.40	$4.96	$3.62
2020	$7.05	$7.41	$5.08	$3.67
2021	$7.38	$7.63	$5.22	$3.71
2022	$7.79	$7.95	$5.30	$3.87
2023	$7.97	$8.18	$5.44	$3.96
2024	$8.44	$8.55	$5.61	$4.04
2025	$8.57	$9.22	$5.83	$4.10
2026	$8.95	$9.12	$6.05	$4.14
2027	$9.27	$9.40	$6.00	$4.21

[1] Based on data presented in Supplemental Table 69 (Reference Case), Table 12 (Reference Case), Table 12 (Low Price Case), Table 13 (Reference Case), and Table 13 (Low Price Case) in the AEO2007.
[2] Natural gas price projections do not include usage charges or intrastate firm or interruptible transportation charges. These costs are accounted for in the economic analysis as discussed in Section 19.0 of Exhibit No. ___[FMPA-1]

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080253-EM EXHIBIT 16
COMPANY FL Municipal Power Agency (Direct)
WITNESS Bradley E. Kushner (BEK-4)
DATE 08-04-08

Table 5
CPWC Summaries for Scenario 1 - Conventional Expansion Scenario
($000)

Case	CPWC of Expansion Plan Including Cane Island 4 in 2011	CPWC of Expansion Plan Without Cane Island 4 in 2011	CPWC Savings for Expansion Plan with Cane Island 4 in 2011
Reference Case	$6,873,504	$6,909,247	$35,763
High Fuel	$7,521,022	$7,558,293	$37,271
Low Fuel	$6,215,140	$6,243,170	$28,030
High Load	$7,780,149	$7,801,735	$21,586
Low Load	$5,994,755	$6,076,238	$81,483
High Capital Cost	$6,984,600	$7,022,491	$37,891
Regulated CO_2	$7,708,642	$7,744,841	$36,200
High Fuel with Regulated CO_2	$8,556,917	$8,594,522	$37,605
High Regulated CO_2	$9,347,371	$9,387,259	$39,888

Table 6
CPWC Summaries for Scenario 2 – Renewables Expansion Scenario
($000)

Case	CPWC of Expansion Plan Including Cane Island 4 in 2011	CPWC of Expansion Plan Without Cane Island 4 in 2011	CPWC Savings for Expansion Plan with Cane Island 4 in 2011
Reference Case	$7,159,378	$7,193,530	$34,153
Regulated CO_2	$7,953,638	$7,987,190	$33,552

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080253-EM EXHIBIT 17
COMPANY FL Municipal Power Agency (Direct)
WITNESS Bradley E. Kushner (BEK-5)
DATE 08-04-08

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition to determine need for Cane Island Power Park Unit 4 electrical power plant in Osceola County, by Florida Municipal Power Agency.	DOCKET NO. 080253-EM DATED: July 2, 2008

RECEIVED-FPSC
08 JUL -2 PM 3:39
COMMISSION CLERK

NOTICE OF FILING CERTIFIED PROOF OF PUBLICATION OF NOTICE OF NEED DETERMINATION HEARING ON A PETITION FOR DETERMINATION OF NEED FOR PROPOSED POWER PLANT IN OSCEOLA COUNTY, FLORIDA

Florida Municipal Power Agency, by and through undersigned counsel, hereby serves notice that the Notice of Commission Hearing and Prehearing Conference on the Petition for Determination of Need for electrical power plant in Osceola County by Florida Municipal Power Agency was published in the Osceola News Gazette on June 28, 2008, pursuant to Order No. PSC-08-0322-PCO-EM (May 15, 2008), and Section 403.519(2), Florida Statutes. Attached is an Affidavit, serving as proof of publication of the Notice.

DATED this 2nd day of July, 2008.

HOPPING GREEN & SAMS, P.A.

Gary V. Perko
Hopping Green & Sams, P.A.
123 S. Calhoun Street
Tallahassee, FL 32314
(850) 222-7500 (telephone)
(850) 224-8551 (facsimile)
Email: GPerko@hgslaw.com

Attorney for Florida Municipal Power Agency

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080253-EM **EXHIBIT** 18
COMPANY Florida Municipal Power Agency
WITNESS Proof of Publication
DATE 08-04-08

DOCUMENT NUMBER-DATE
05760 JUL-2 08
FPSC-COMMISSION CLERK

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing Notice of Filing Certified Proof of Publication of Notice of Need Determination Hearing on a Petition for Determination of Need for Proposed Power Plant in Osceola County, Florida, in Docket No. 080253-EM, was served upon the following by U.S. Mail on this 2nd day of July, 2008:

Katherine Fleming
Senior Attorney
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, Florida 32399-0850

Attorney

PETITION FOR DETERMINATION OF NEED FOR CANE ISLAND UNIT 4 ELECTRICAL POWER PLANT IN OSCEOLA COUNTY BY FLORIDA MUNICIPAL POWER AGENCY

NOTICE IS HEREBY GIVEN that a hearing will be held before the Florida Public Service Commission in the above docket regarding the petition of Florida Municipal Power Agency for determination of need for an electrical power plant in Osceola County, at the following time and place:

Monday, August 4, 2008, 9:30 A.M.
Room 148, Betty Easley Conference Center
4075 Esplanade Way
Tallahassee, Florida

PURPOSE AND PROCEDURE

The purpose of this hearing will be for the Commission to take final action to determine the need, pursuant to Section 403.519, Florida Statutes, for the Participants' proposed electrical power plant in Osceola County, Florida. This hearing will also consider any motions or other matters that may be pending at the time of the hearing. The Commission may rule on any such motions from the bench or may take the matters under advisement. This proceeding shall: (1) allow the applicant to present evidence and testimony in support of their petition for a determination of need for the proposed electrical power plant; (2) permit any intervenors to present testimony and exhibits concerning this matter; (3) permit members of the public who are not parties to the need determination proceeding the opportunity to present testimony concerning this matter; and (4) allow for such other purposes as the Commission may deem appropriate.

The proceedings will be governed by the provisions of Chapter 120, Florida Statutes, Section 403.519, Florida Statutes, and Chapters 25-22 and 28-106, Florida Administrative Code.

Under Section 403.519, the Commission is the sole forum for the determination of need for the proposed electrical power plant. In making its determination, the Commission must take into account the need for electric system reliability and integrity, the need for adequate electricity at a reasonable cost, the need for fuel diversity and supply reliability, and whether the proposed plant expansion is the most cost-effective alternative available, and whether renewable energy resources and technologies, as well as conservation measures, are utilized to the extent reasonably available. In addition, the Commission must expressly consider the conservation measures taken by or reasonably available to the applicant or its members which might mitigate the need for the proposed plant and may consider other matters within its jurisdiction which it deems relevant. The Commission's determination of need for the proposed plant shall create a presumption of public need and necessity and shall serve as the Commission's report required by subsection 403.507(2), Florida Statutes. An order entered by the Commission pursuant to this hearing shall constitute final agency action.

Only issues relating to the need for the proposed power plant will be heard at this hearing. Separate public hearings will be held before the Division of Administrative Hearings at a later date to consider environmental and other aspects of the proposed plant and associated facilities, as required by the "Florida Electrical Power Plant Siting Act," Sections 403.501-403.518, Florida Statutes.

Members of the public who are not parties to the need determination proceeding will have an opportunity to present testimony regarding the need for the proposed plant. All members of the public who wish to offer testimony should be present at the beginning of the hearing, 9:30 a.m., Monday, August 4, 2008. All witnesses will be sworn in and will be subject to cross-examination at the conclusion of their testimony. By providing public testimony, a person does not become a party to the proceeding. Anyone wishing to become a party in this need determination proceeding should file an intervention petition pursuant to Rule 25-22.039, Florida Administrative Code, with the Director of the Commission's Division of the Commission Clerk and Administrative Services, at the address listed below. Copies of the petition should be sent by mail to all parties. Those wishing to intervene in these proceedings, unless appearing on their own behalf, must be represented by an attorney or other person who can be determined to be a qualified representative pursuant to Chapter 120, Florida Statutes, and Rule 28-106.106, Florida Administrative Code. Petitions for leave to intervene must be filed at least five (5) days before the final hearing, must conform with Rule 28-106.201(2), Florida Administrative Code, and must include allegations sufficient to demonstrate that the intervenor is entitled to participate in the proceedings as a matter of constitutional or statutory right or pursuant to Commission rule, or that the substantial interests of the intervenor are subject to determination or will be affected through the hearing.

Written comments regarding the need for the proposed plant and associated facilities may be sent to the Commission at the following address:

Office of Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850
Re: Docket No. 060685-EC

GENERAL LOCATION AND PROJECT DESCRIPTION

FMPA proposes the construction of one new unit, to be known as Cane Island Unit 4, which will be a high-efficiency, 1x1 F class, natural gas-fueled combined cycle unit, consisting of a combustion turbine and a heat recovery steam generator that will drive a steam turbine generator. The new unit will be capable of generating nominally 300 megawatts (MW). The projected in-service date for Cane Island Unit 4 is May 1, 2011.

The proposed new unit will be wholly owned by FMPA and operated under contract by Kissimmee Utility Authority (KUA), an "All-Requirements Power Supply Project" (ARP) member utility. All of the generation capacity from the unit will be committed to ARP members for retail sale to their customers.

PREHEARING CONFERENCE

A prehearing conference will be held at:
Monday, July 21, 2008, 9:30 a.m.
Room 148, Betty Easley Conference Center
4075 Esplanade Way
Tallahassee, Florida

The purpose of this prehearing conference is to: (1) simplify the issues; (2) identify the positions of the parties on the issues; (3) consider the possibility of obtaining admissions of fact and of documents which will avoid unnecessary proof; (4) identify exhibits; (5) establish an order of witnesses; and (6) consider such other matters as may aid in the disposition of the action.

JURISDICTION

This Commission is vested with jurisdiction over the subject matter of this proceeding by the provisions of Chapter 366, and section 403.519, Florida Statutes. This proceeding will be governed by those statutes, in addition to Chapter 120, Florida Statutes, and Rules 25-22 and 28-106, Florida Administrative Code.

Any person requiring some accommodation at this hearing because of a physical impairment should call the Division of the Commission Clerk and Administrative Services at (850) 413-6770, at least 48 hours prior to the hearings. Any person who is hearing or speech impaired should contact the Florida Public Service Commission by using the Florida Relay Service, which can be reached at 1-800-955-8771 (TDD).

A copy of the Applicant's petition for determination of need and supporting exhibits is available for public inspection during normal business hours at the following location:

Florida Public Service Commission
Division of the Commission Clerk and Administrative Services
4075 Esplanade Way
Room 110-Betty Easley Conference Center
Tallahassee, Florida
June 26, 2008

AFFIDAVIT
IN ACCORDANCE WITH CHAPTER 50, FLORIDA STATUTES

OSCEOLA NEWS GAZETTE
Published Twice-Weekly
City of Kissimmee, Osceola County, Florida

STATE OF FLORIDA
COUNTY OF OSCEOLA.

Before the undersigned authority personally appeared Dinya I. Hiebert, who on oath says that he or she is Legal Clerk of the Osceola News Gazette, a twice-weekly newspaper of general circulation, printed in the English language, published at Kissimmee in Osceola County, Florida; that the attached copy of advertisement being a Notice in the matter of the Petition for a Determination of Need for an Electrical Power Plant in Osceola County before the Florida Public Service Commission, was published in said newspaper in the issue of June 28, 2008

Affiant further says that the Osceola News Gazette is a newspaper published at Kissimmee, in said Osceola County, Florida, and that the said newspaper has heretofore been continuously published in said Osceola County, Florida, twice a week and has been entered as periodicals matter at the post office in Kissimmee, in said Osceola County, Florida, for a period of one (1) year next preceding the first publication of the attached copy of advertisement; and affiant further says that he or she has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

Sworn to and subscribed before me this 30th day of June 2008, by Dinya I. Hiebert, who is personally known to me or who has produced _____ as identification.

Notary Signature: Carol L Gorrell
Notary Seal or Stamp:

CAROL L. GORRELL
MY COMMISSION # DD360139
EXPIRES: OCTOBER 24, 2008

DOCUMENT NUMBER-DATE
05760 JUL-2 8
FPSC-COMMISSION CLERK