060220-EC

SEMINOLE ELECTRIC COOPERATIVE, INC.

Petition to Determine Need for

Electric Power Plant

March 2006

Direct Testimony of:

Lane Mahaffey

Seminole Electric
COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

060220-EC

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

SEMINOLE ELECTRIC COOPERATIVE, INC.

DIRECT TESTIMONY OF LANE MAHAFFEY

DOCKET NO. 06____-EU

MARCH 10, 2006

Q. **Please state your name and business address.**

A. My name is Lane Mahaffey. My business address is 16313 North Dale Mabry Highway, Tampa, Florida 33688-2000.

Q. By whom are you employed and what is your position?

A. I am employed by Seminole Electric Cooperative, Inc. (Seminole) as Director of Corporate Planning in the Strategic Services Division.

Q. Please describe your duties and responsibilities in that position.

A. I am responsible for overseeing the development and implementation of Seminole's long term strategic plan, developing and updating long-term electrical load forecasts, and planning adequate, reliable and economic generation resources to meet the requirements of Seminole's member cooperatives (Members).

Q. Please describe your educational background and business experience.

A. I graduated from the University of South Florida with a Bachelor of Science Degree in Electrical Engineering in 1976. I began work for Florida Power Corporation (now

Progress Energy Florida), first as a cooperative student and upon graduation as a System Performance Engineer in the production (power plant) testing department. In 1979, I began work for the City of Vero Beach, Florida as Results Engineer in the Vero Beach Municipal Power Plant. In that capacity, I was responsible for overall plant efficiency and supervised the system operations department (system control center) and the plant electrical and instrument shops. In 1982, I joined Seminole as Supervisor of System Operations with responsibility for the system control center operation. In 1984, I was promoted to Manager of System Operations with similar responsibilities. In 1993, I was promoted to Director of Operations with responsibility for the System Operations Department and the Fuels Department. In 1996, I was named Director of Strategic Planning and Market Analysis (strategic planning, load forecasting, and market analysis responsibilities), and later Director of Strategic Planning and Marketing (strategic planning, load forecasting, and energy marketing). In 2002, I was named Director of Corporate Planning.

Q. What is the purpose of your testimony?

A. My testimony addresses the need of Seminole, its Members and their member/consumers for SGS Unit 3, the most cost-effective alternative available to meet their need for reliable and adequate electricity at a reasonable cost in 2012 and beyond. My testimony has six primary elements. First, I describe Seminole's generation planning process. Second, I review Seminole's reliability criteria that are used in determining capacity need. Third, I describe Seminole's evaluation of self-build and purchased power alternatives that led to the decision to add SGS Unit 3.

Fourth, I describe Seminole's assessment of risk associated with this capacity decision. Fifth, I discuss the recommendation by Seminole's Staff to our Board of Trustees to proceed with SGS Unit 3 and the Board's subsequent approval. Sixth, I describe Seminole's and Peninsular Florida's need for SGS 3 and the adverse consequences to Seminole and its Members in the event the proposed project is not constructed.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring the five exhibits listed below, which are attached to my testimony.

Exhibit LTM-1 Seminole Capacity Need Without SGS Unit 3

Exhibit LTM-2 Seminole Power Supply Resource Requirements

Exhibit LTM-3 Summary of Bus Bar Costs

Exhibit LTM-4 Present Worth Revenue Requirements (PWRR) Results

Exhibit LTM-5 Cumulative and Annual PWRR Results

Q. Are you sponsoring any part of the Need Study in this proceeding?

A. Yes. I am co-sponsoring Sections V, VI, VII, and IX of the Need Study document. I am also sponsoring Need Study Appendices E, G, and K.

I. SEMINOLE'S GENERATION RESOURCE PLANNING PROCESS

Q. What is the objective of Seminole's generation resource planning process?

A. The fundamental objective of Seminole's planning process is to provide a portfolio of generation resources that ensures reliable wholesale electric service at a competitive cost. Underlying this fundamental objective is a strong belief that, over the long term, a reliable and competitive generation portfolio must be based on a diverse generation and fuel mix to provide price stability.

Q. Please provide an overview of Seminole's generation resource planning process.

A. The load forecast is a starting point. As Mr. Lawton describes in more detail, Seminole works with its ten Members to develop individual forecasts, which roll up into an aggregate Seminole load forecast. Once the load forecast is developed, Seminole assesses the amount of capacity needed to meet the load forecast plus additional capacity necessary to meet Seminole's reliability criteria.

After determination of the total generating capacity need and any resulting capacity deficiency, Seminole further analyzes the capacity need in order to determine the type of capacity addition which would contribute optimally to the overall generation mix (i.e., base, intermediate, or peaking). This is done using a combination of analytical techniques involving load duration curve analysis, bus bar cost analysis, and/or iterative production costing runs.

Next, Seminole must evaluate its alternatives to meet the identified capacity need. One or more self-build alternatives are developed. This is typically done by an independent engineering consulting firm. Then, Seminole solicits competitive bids for purchased power via a request for proposals (RFP). Seminole may also be involved in continuing negotiations with other parties or existing suppliers.

The self-build alternative(s) are evaluated against purchased power alternatives and, ultimately, a recommendation is made to Seminole's Board as to what individual resources (or combination of resources) should be pursued.

Q. Please describe Seminole's generation portfolio and address whether the above described planning process has been effective in meeting Seminole's planning objectives.

A. Seminole's generation portfolio currently consists of approximately 60% purchased power. This is the result of an aggressive competitive bidding program wherein Seminole strives to ensure that its decisions among power supply alternatives are based on the best available market information in comparison to self-build alternatives which are viable at that time. Over the past two decades, the wholesale market in Florida has produced competitive pricing from independent power producers eager to enter the Florida market. Seminole has also been able to negotiate favorable purchased power arrangements with investor-owned and municipal utility partners. These market conditions have allowed Seminole to contract for a significant portion of its power supply resources from a range of purchased power resources, in

combination with self-build projects. The resulting resource mix has provided competitive and reliable wholesale power to Seminole's Members, while allowing Seminole the flexibility to replace these resources with other sources of supply in response to major market trends (e.g., high natural gas prices).

II. SEMINOLE'S GENERATING CAPACITY NEED IN 2012

Q. Please describe Seminole's reliability criteria and related reserves.

A. The total amount of generating capacity and reserves required by Seminole is affected by Seminole's load forecast and a set of reliability criteria. Reserves serve two primary purposes: to provide replacement power during generator outages and to address load forecast uncertainty.

Seminole has two principal reliability criteria: (1) a minimum reserve margin of 15% during the peak season, and (2) a 1% Equivalent Unserved Energy (EUE) limitation. Both criteria help maintain the reliability of Seminole's power supply to its Members and limit Seminole's need to rely on emergency reserve purchases from interconnected neighboring systems.

Q. Please describe in general terms the load forecast which Seminole uses as the basis for its capacity need.

A. Seminole provides firm bulk power supply (at wholesale) to its ten Members which serve retail consumers in Peninsular Florida. Seminole's Members are described in detail in the Need Study document and in Mr. Woodbury's testimony. Seminole

serves these ten Members under long term wholesale power contracts. The original contracts were for 45 years, extending through July 2020. Seven of Seminole's ten Members have extended their contracts an additional 25 years (through 2045). Seminole has reached agreement with two of the remaining three Members (Clay Electric Cooperative and Suwannee Valley Electric Cooperative) to extend their contracts through 2045, contingent upon certain contract amendment terms which are still under development. Thus, Seminole is planning on serving nine of the ten Members through 2045, with the responsibility for serving the tenth Member still unresolved. However, since the extended wholesale power contracts are currently only finalized with seven of ten Members, Seminole has based its capacity need and economic assessments for this determination of need on serving only the seven Members that have already signed contract extensions.

Q. Please describe Seminole's capacity needs in future years and explain how SGS Unit 3 will meet a portion of those needs.

A. Seminole's need assessment process demonstrated that, in order to meet Seminole's established reliability criteria, over 1200 MW of additional capacity will be needed in 2012. This capacity need results from the scheduled expiration of purchased power contracts (i.e., 546 MW Oleander Power Project, L.P., 360 MW Calpine Construction Finance Company, L.P., and 55 MW Lee County, Florida), planned annual adjustments in Seminole's PEF Partial Requirements contract, plus expected load growth. By 2015, the capacity need will increase to over 4600 MW. The increased capacity needed by 2015 results from the combined effect of the changes mentioned

previously, plus the scheduled expiration of additional purchased power contracts (i.e., 356 MW Hardee Power Partners, Limited, 364 MW Reliant Energy Florida, LLC, 450 MW Progress Energy Florida System Intermediate, Progress Energy Florida Partial Requirements), and additional load growth.

Since Seminole's cumulative need for capacity in 2012 exceeds 1200 MW and increases significantly thereafter, SGS Unit 3 alone only meets a portion of Seminole's projected load and reserve requirements. Seminole's total additional capacity needs based on serving seven Members after 2020 (i.e., consistent with the basis of the economic justification) are summarized in tabular format in Exhibit LTM-1. A graphical overview of Seminole's overall resource portfolio is included as Exhibit LTM-2. Page 1 of Exhibit LTM-2 shows Seminole's capacity needs with only seven Members served after July 2020, representing the Member load commitment assumption which underlies Seminole's economic case. Page 2 of Exhibit LTM-2 shows Seminole's capacity needs with nine Members served after 2020 (for reference only).

Q. Is SGS Unit 3 needed for reliability or for economic reasons?

A. Both. As noted above, SGS Unit 3 fulfills a portion of Seminole's reliability need in 2012 and beyond. Thus, SGS Unit 3 is clearly needed for reliability. At the same time, the selection of SGS Unit 3 to serve as a base load resource, as opposed to alternative types of capacity resources, is motivated by economics. So SGS Unit 3 is needed both to maintain reliability and to provide electricity at a reasonable cost.

Q. Describe how Seminole determined that a portion of its 2012 capacity needs should be met with a "base load" resource.

A. Most electric utilities, including Seminole, employ a mix of generation which includes resources generally characterized as base, intermediate, and peaking. Base load resources are those resources which typically operate around the clock to serve consumer demands. Intermediate resources are typically cycled on during the daytime hours and off during the lower demand nighttime hours. Peaking resources typically operate only during peak hours of the day, mostly during peak seasons, and occasionally provide reserve (backup) capacity for short periods to replace base and intermediate capacity during outages.

Seminole uses a combination of analytical techniques to determine how much of its total capacity need in future years should be met with each type of resource. Load duration curve techniques provide a rough estimate of an optimal system generation mix. These curves allow a determination of the amount of capacity on a system which will operate above a specified capacity factor. In order to use a load duration curve approach for determining base load capacity need, first an estimate is made of the typical operating profile for base load resources in terms of an annual capacity factor. Such an estimate could be made by analyzing bus bar costs (i.e., the total cost to operate a base load generating technology on a $ per MWh basis). Seminole used this approach to estimate the amount of base load capacity it needed in advance of its competitive bid for purchased power. However, these load duration curve techniques only provide an initial estimate. The detailed economic analyses comparing one

alternative against another is the real determinant of the most economic resource(s) and/or resource combination and how large the MW commitment for a selected type of resource should be at a particular time.

Q. How much base load capacity does Seminole need?

A. Seminole originally estimated a need for up to 600 MW of base load capacity as early as 2009. Ultimately, as load forecasts and fuel price forecasts were updated, and as specific self-build and purchased power alternatives were studied, Seminole concluded that 750 MW of base load capacity should be added in the 2012 time frame.

III. EVALUATION OF SELF-BUILD VERSUS PURCHASED POWER ALTERNATIVES

Q. Please describe how Seminole developed its self-build alternatives.

A. As described more fully in Mr. Klover's testimony, in August 2004, Burns & McDonnell completed a feasibility study assessing Seminole's self-build alternatives to provide base load capacity. The feasibility study concluded that a third 600 MW (nominal) pulverized coal unit at the Seminole Generating Station was the best and most economic self-build alternative. This feasibility study provided the expected costs of construction and the schedule associated with achieving commercial operation for the prospective coal unit. Burns & McDonnell also provided costs for a gas combined cycle unit and a cost comparison which concluded that a coal unit was the lower cost alternative.

Q. What other generation technologies did Burns & McDonnell consider to meet Seminole's need for base load capacity?

A. In addition to the recommended pulverized coal technology and gas combined cycle technology, the Burns & McDonnell study addressed integrated coal gasification with combined cycle (IGCC). As discussed in Mr. Klover's testimony, Burns and McDonnell determined that IGCC technology remains relatively unproven in commercial scale electric applications, and that the reliability and cost risks are too high at the present time (i.e., until these technologies have been further developed by others).

Q. Did Seminole consider any other technologies as a self-build alternative?

A. Yes. Seminole staff considered circulating fluidized bed (CFB) technology. As discussed further by Mr. Opalinski, Seminole concluded, based on industry information available at the time, that large scale CFB projects would be more costly than a pulverized coal project and would not provide any offsetting benefits. Consequently, Seminole did not ask Burns & McDonnell to consider CFB technology. Seminole was also a joint participant in a feasibility study for a separate jointly owned coal fired unit with several Florida municipalities (i.e., 150 MW share of a 600-800 MW unit). This feasibility study was conducted by a separate independent engineering consulting firm which had made similar conclusions to Burns & McDonnell on the feasibility of pulverized coal technology. Therefore, Seminole ultimately had three self-build alternatives for serving portions of its base

load need: a pulverized coal unit at the existing Seminole Generating Station; a share of a joint coal unit which was not yet sited; and a green-field gas combined cycle unit.

Q. Was nuclear generation considered?

A. Yes and no. The resurgence of advanced nuclear technology as a base load alternative is a promising development for the electric industry. Seminole's staff is interested in opportunities to participate in future projects. However, the early licensing activities currently underway with the Department of Energy by various industry consortia are targeting the 2015/16 time frame as the earliest commercial date for new nuclear installations. This is too late for Seminole's current need. However, Seminole will have additional needs for base load capacity by the 2014/2015 time frame. Hopefully, all of the above alternative base load technologies will be viable and can be evaluated as alternatives to meet Seminole's future capacity needs.

Q. Describe Seminole's process for evaluation of its self-build generation alternatives versus its purchased power alternatives.

A. In September 2004, Seminole received bids for purchased power alternatives in response to its RFP issued in April 2004. Following receipt of the bids, Seminole's staff performed an initial screening of the offers for completeness and responsiveness. Staff also reviewed the offers involving construction of new capacity to determine if the proposed equipment was technically and environmentally viable and if the unit performance information provided by the bidders was reasonable. None of the bids

were excluded from further consideration as a result of either the administrative or the technical screening. All of the bidders were contacted on September 16, 2004 for clarification of the specific terms and conditions of their offers, including pricing and unit characteristics. In order to insure that all possibilities to find a purchased power alternative had been investigated, on October 28, 2004, the bidders with the lowest cost proposals were asked to refresh and revise their pricing and other applicable terms and conditions by November 10, 2004. The RFP process is described in greater detail in Ms. Novak's testimony.

Economic screening of the purchased power proposals was accomplished by comparing "bus bar costs." Bus bar costs are a representation of the all-in cost for each alternative divided by the energy produced. The bus bar cost (in $ per MWh) for each alternative was calculated for each of three different operational scenarios (i.e., all proposals, including the three self-build alternatives, were evaluated at 70%, 80% and 90% capacity factors, representing the base load operation range). The analysis included all fixed and variable costs, including fuel expense. Fuel costs and other applicable assumptions which were not specifically tied down by the RFP proposals were standardized for consistency in the evaluation. The bid-to-bid comparisons (and associated ranking) were done on a levelized $/MWh basis, calculated over a twenty-year period, on a nominal and present worth basis.

Q. Please describe the generation alternatives that were evaluated using Seminole's bus bar cost comparison.

A. As further described in Ms. Novak's testimony, Seminole evaluated three self-build alternatives and fourteen purchased power alternatives. The three self-build alternatives were a pulverized coal unit at Seminole's existing coal site, a participation share in a jointly-owned pulverized coal unit, and a greenfield gas combined cycle unit. The purchased power alternatives included purchased capacity and energy from three greenfield pulverized coal units (one in Florida and two out-of-state), three greenfield gas combined cycle units (with nine proposals reflecting unit configuration alternatives and pricing options), and one existing gas combined cycle unit (with two unit configuration alternatives). The proposal from the existing gas combined cycle unit was at a significantly higher cost than the other alternatives, and for this reason, only the best of two configuration alternatives was carried forward in the bus bar cost comparison.

Q. Describe the results of Seminole's economic screening evaluation.

A. The bus bar cost comparison revealed a significant economic advantage of coal-based alternatives over gas-based alternatives, and further, that self-build alternatives for both coal and gas were significantly favorable relative to the purchased alternatives resulting from the RFP process. The results of this screening process are included as Exhibit LTM-3.

Q. What action did Seminole take upon completion of the economic screening described above?

A. At the December 2004 meeting of Seminole's Board of Trustees, staff presented its economic assessment of self-build and purchased power options. Staff concluded that the economic favorability of a self-build coal unit (Seminole's lowest cost self-build alternative) over any of the purchased power alternatives was so significant that further negotiations would not yield a change in the rankings. On this basis, staff recommended, and the Board approved, discontinuing negotiations with the RFP bidders related to their base load proposals.

The Seminole Board also directed staff to continue background activities associated with a pulverized coal unit. Staff also reported to the Board that a consulting firm had been engaged to assist with a risk assessment of the economic evaluation of alternatives. The risk assessment would compare the economic risks of a coal-based scenario and an alternative all-gas scenario utilizing gas combined cycle technology, as both generation technologies were described in the Burns & McDonnell study.

IV. EVALUATION AMONG THE SELF-BUILD ALTERNATIVES

Q. Describe how Seminole proceeded in its evaluation of the self-build alternatives.

A. As described above, Seminole initially used a "bus bar cost" comparison in determining that its self-build coal unit alternatives (specifically a pulverized coal unit at Seminole's Palatka site and a prospective 150 MW share of a separate coal unit) were its most economic alternatives. As a further test of the validity of these

results, staff proceeded with a risk assessment of the prospective coal strategy versus an all-gas strategy (both self-build). The risk assessment would initially involve further evaluation of these alternatives on a present worth revenue requirements basis.

A self-build 600 MW coal unit (lowest cost option) in combination with the 150 MW joint coal unit participation (next lowest cost option) was compared to an all-gas scenario based around the self-build gas combined cycle technology and costs from the Burns & McDonnell study. The comparative results from these two competing cases were then subjected to a probability-based risk assessment.

As noted above, a consulting firm (R.W. Beck) had been commissioned to develop the analytical tools necessary for Seminole to perform detailed risk analysis of power supply alternatives, and to assist with the risk analysis of the coal vs. gas scenarios. These analytical tools assign probability distribution functions (PDFs) around selected variables, and using various probability techniques, including Monte Carlo simulations, evaluate the aggregate risk of the variables in combination, as opposed to traditional scenario analysis which looks at one variable at a time.

The approach used in the risk analysis included (i) preparing market data inputs (such as gas prices and coal prices), environmental cost inputs, inputs on future generation costs by type of plant (including capital costs, operating costs, etc.) and load forecast inputs; (ii) defining the variability of major inputs that could impact power supply

decisions ("risk" variables); and (iii) preparing PDFs that describe the uncertainty of each risk variable.

Based on the PDFs defined for each risk variable, the assessment process used stochastic modeling and statistical analysis techniques to analyze how (in aggregate) these risks could impact Seminole's projected annual power costs. The results of the risk assessment included a projection of the potential range (with a certain confidence level) and expected outcome of annual power costs and average Member rates under the two options (coal and gas) being evaluated.

Q. Briefly describe the results of the risk assessment.

A. The present worth revenue requirements analysis which served as the underlying base case for the risk assessment yielded a projected savings of $476 million (2005 dollars) for the studied coal strategy versus an all-gas strategy. The risk assessment concluded there was an 80% probability that the coal strategy would yield lower costs over the study period than the all-gas strategy. The results of the present worth revenue requirement savings analysis and the risk assessment were reviewed with Seminole's Board at its February 2005 meeting. The final report of Seminole's Risk Assessment of Base Load Options is included as Appendix K to the Need Study.

Q. After its decision to proceed with a self-build coal project, Seminole chose a 750 MW unit instead of its original 600 MW unit in combination with the 150 MW coal unit participation. Describe the circumstances which led to Seminole's decision.

A. In early 2005, as the purchase power proposals and self-build options were being evaluated, refined cost estimates for the joint coal project were received which had increased significantly from prior estimates. In addition, the anticipated in-service date for the joint unit, which was originally in 2009, was now 2011 or 2012. Further, a purchased power option Seminole had negotiated with the joint participants (i.e., a purchased power structure instead of equity ownership) was deemed infeasible by the other participants due to financing difficulties. In consideration of the higher costs, the later commercial operation date, and the loss of the purchased power option for the joint project, Seminole decided to re-evaluate its own self-build alternative to assess the viability of a larger unit.

Burns & McDonnell was commissioned to update its feasibility study. The updated study indicated that a 750 MW (nominal) unit at Seminole Generating Station was technically feasible and could be permitted on the site. An economic analysis of the larger unit showed that the incremental 150 MW of capacity in the self-build unit could be constructed and operated at a significantly lower cost than the 150 MW share of the planned joint unit. The decision was made to discontinue further participation in the joint unit project.

V. SEMINOLE BOARD'S APPROVAL OF THE SGS UNIT 3 PROJECT

Q. What was the recommendation of Seminole's staff to the Board regarding SGS Unit 3, and what was the result?

A. At the March 2005 meeting of the Board of Trustees, staff reviewed the chronology of planning activities for base load capacity since 2003. Technical staff also reviewed a technology study performed by Burns & McDonnell relating to SGS 3 unit design details. Staff recommended, and the Board approved, proceeding with the planning, permitting, and construction of SGS Unit 3 as a 750 MW supercritical pulverized coal unit, for commercial operation in May 2012.

VI. UPDATED ECONOMIC ANALYSIS

Q. Has Seminole updated its assessment since the March 2005 project approval?

A. Yes. During the summer of 2005, staff updated its economic assessment. A new load forecast was approved by Seminole's Board in July 2005, and the fuel price forecast was updated in August 2005. Due to revisions of these and other input assumptions, staff updated its economic comparisons.

Q. Please describe Seminole's updated economic assessment.

A. Seminole performed two separate analyses: (1) a present worth revenue requirements comparison for a 750 MW pulverized coal unit versus an all-gas scenario, using updated costs for the coal unit and updated load and fuel forecasts; and (2) a case study using a present worth revenue requirements analysis and the December 2004 base case assumptions, which compared the original self-build alternatives, the best

purchased power scenario, and the 750 MW pulverized coal unit. The economic comparisons in (2) were designed to provide a bridge between the original decision to eliminate all purchased power alternatives and Seminole's updated plan to proceed with a more economical 750 MW unit as opposed to a 600 MW unit. The updated coal versus gas analysis in (1) revealed a projected present worth revenue requirement savings of $498 million (2005 dollars). The bridge analysis in (2) revealed cumulative present worth revenue requirement savings as follows:

- $123 million savings for a 750 MW SGS Unit 3 versus a 600 MW SGS Unit 3 in combination with the 150 MW joint coal unit participation option.
- $600 million savings for a 750 MW SGS Unit 3 versus an all gas case built around an equivalent amount of gas combined cycle.
- $684 million savings for a 750 MW SGS Unit 3 versus a 600 MW Invenergy coal unit (best purchased power offer) in combination with the 150 MW joint coal unit participation option.

A summary of the results of Seminole's updated analyses as described above is included as Exhibit LTM-4. The annual detail for Seminole's updated economic results comparing SGS Unit 3 to an alternative all-gas scenario is included as Exhibit LTM-5.

VII. ADVERSE CONSEQUENCES IF SGS 3 IS NOT CONSTRUCTED

Q. What will be the projected impact on the reliability of service to Seminole's Members and their member/consumers if SGS Unit 3 is not constructed to meet the identified capacity needs in 2012?

A. Approximately half of Seminole's generation portfolio consists of purchased power contracts. The expiration of some of these contracts in the time frame of the proposed unit addition combined with projected growth in our Member service areas leave a deficiency of over 1200 MW in total capacity need by the summer of 2012. The proposed unit addition satisfies a significant portion of this total need. If SGS Unit 3 were not constructed timely, and in the absence of other alternative capacity additions, Seminole would not meet its planning reliability criteria. That would leave our Members and their member/consumers without reliable wholesale service and would result in an unacceptably high risk of service interruptions.

Q. What will be the projected economic impact on Seminole's Members and their member/consumers if the SGS Unit 3 project is not constructed to meet the identified capacity needs in 2012?

A. Seminole's election to build a 750 MW coal unit, as opposed to a purchased power contract or building another type of unit (e.g., gas combined cycle, combustion turbine, etc.), was based on economic studies which demonstrated that the recommended unit will provide the lowest cost base load power for our Members' consumers. In the event SGS Unit 3 is not constructed timely, the economic studies which support this need application show that Seminole's Members and their

member/consumers would be significantly harmed through higher costs and greater price uncertainty. The additional cost Seminole and its Members and their retail member/consumers would incur is essentially the loss of $498 million of expected savings attributable to SGS Unit 3.

Q. What other consequences will there be to Seminole and its Members and their member/consumers if SGS Unit 3 is not constructed as planned?

A. In 2006, Seminole will rely on natural gas for 37% of its system energy requirements. By 2013, the first full year of operation of SGS Unit 3, Seminole's reliance on natural gas will have decreased to approximately 29%. In the absence of SGS Unit 3, the resulting level of reliance on natural gas to meet Seminole's system energy requirements would be approximately 52%, imposing unacceptable risks associated with price uncertainty and weather-related fuel availability. Such fuel-related risks threaten Seminole's reliability of service, and the increased price uncertainty would flow through to Seminole's wholesale rates and the retail rates of Seminole's Members.

VIII. PENINSULAR FLORIDA'S CAPACITY NEED

Q. Is Seminole's need for SGS Unit 3 consistent with Peninsular Florida's capacity need?

A. Yes. By the year 2014, Peninsular Florida utilities report that in aggregate, they will require over 18,000 MW of new generating capacity (i.e., based on the July 2005 issue of the FRCC Regional Load and Resource Plan). Seminole and its ten Members

are, in aggregate, among the fastest growing electric systems in Peninsular Florida, and Seminole's needs are a significant portion of the statewide need for generating capacity. The addition of a 750 MW unit at Seminole's existing SGS site will contribute to meeting the statewide need for power.

Similarly, the aggregate reliance of Peninsular Florida on natural gas for electric energy will have increased from 32% in 2005 to 46% in 2011. By 2013, currently announced coal additions (including SGS Unit 3) will have increased solid fuel's energy share and, correspondingly, decreased the portion served by natural gas by approximately 2% (reducing the state's reliance on natural gas from 46% to approximately 44%). Even with coal additions by Seminole and others in the 2012 time frame, natural gas is projected to increase to 44% of Peninsular Florida's energy needs by 2013.

Q. Please summarize your testimony.

A. Seminole needs a significant amount of additional generating capacity by the year 2012, and a portion of such capacity should operate as a base load resource. These needs are due primarily to expiring purchased power contracts and load growth. An engineering consultant's study recommended a modern pulverized coal unit as the best self-build option. A competitive bidding process provided purchased power alternatives for comparison to the self-build option(s). A rigorous analytical evaluation demonstrated that a 750 MW pulverized coal unit, SGS Unit 3, was the most economical alternative to meet Seminole's base load requirements in 2012. A

risk assessment provided additional assurance that a coal unit is the most economical alternative under a range of alternative scenarios. Seminole's Board of Trustees, consisting of Trustees from Seminole's Members (wholesale customers), reviewed the economic studies described above and directed Seminole to proceed with planning activities necessary to construct SGS Unit 3.

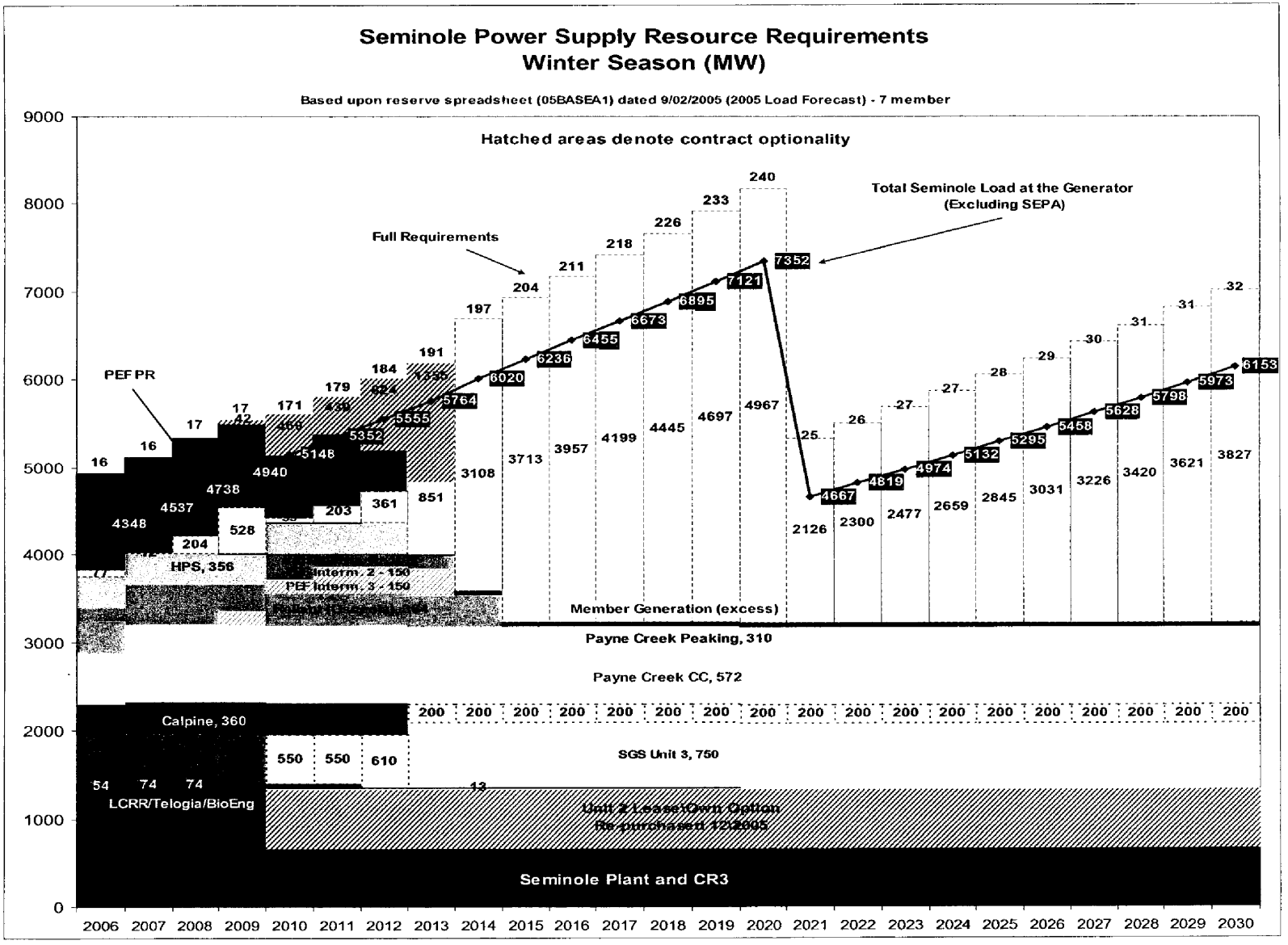
Seminole requests a favorable finding from the Commission on Seminole's application for a determination of need for SGS Unit 3. An adverse finding would jeopardize Seminole's ability to provide reliable service to Seminole's Members and their member/consumers, would significantly increase the future costs of Seminole's wholesale electric service, and would create an unacceptable level of reliance on natural gas generation.

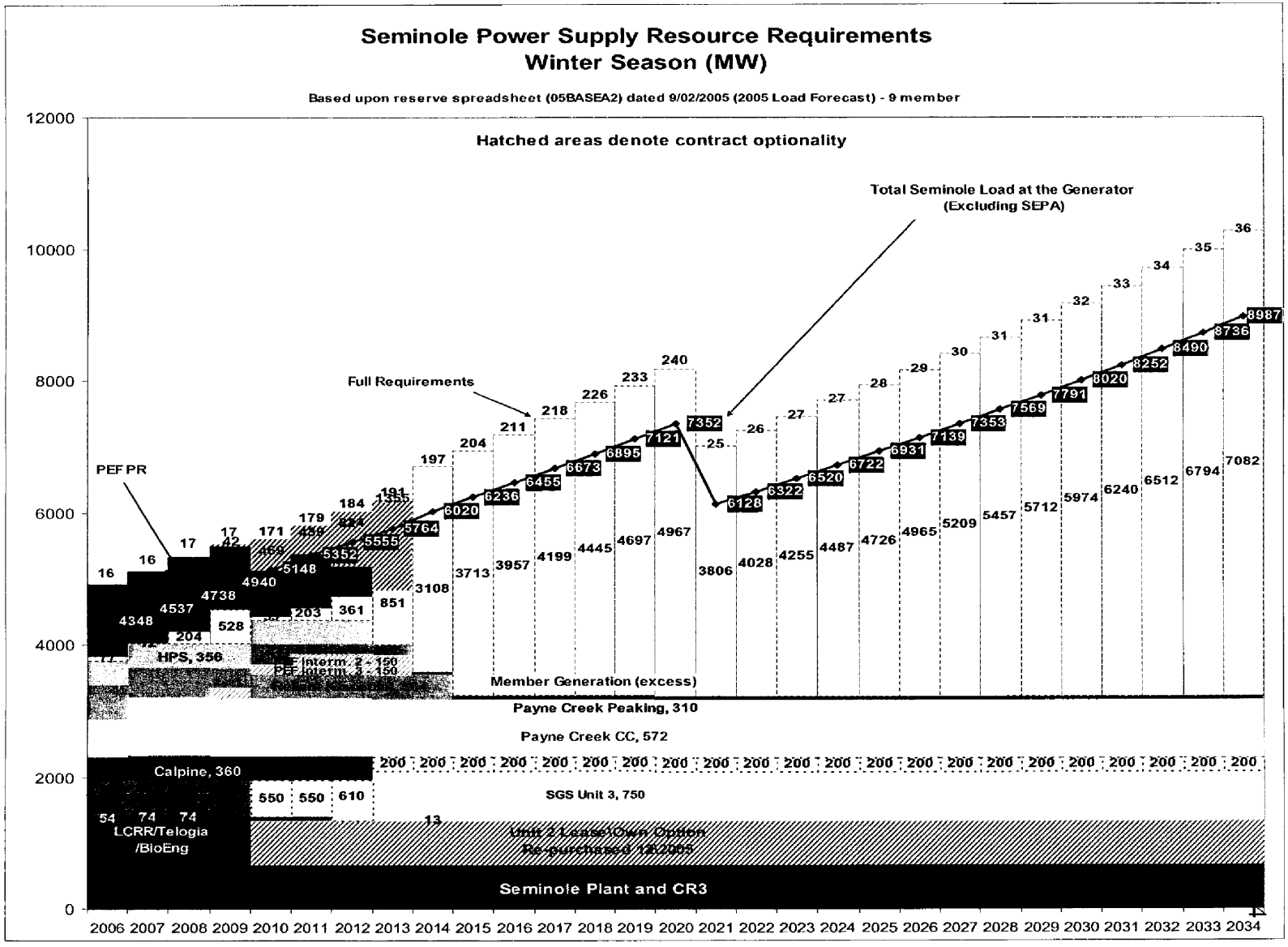
Q. Does this conclude your testimony?

A. Yes.

Seminole's Capacity Need
Without SGS Unit 3

Year	Winter MW	Summer MW
2012	971	1261
2013	1801	1702
2014	4058	3440
2015	4663	3620
2016	4907	3794
2017	5149	3977
2018	5395	4160
2019	5647	4346
2020	5917	4432
2021	3076	2255
2022	3250	2377


Seminole Power Supply Resource Requirements
Winter Season (MW)
Based upon reserve spreadsheet (05BASEA1) dated 9/02/2005 (2005 Load Forecast) - 7 member
Hatched areas denote contract optionality
Total Seminole Load at the Generator (Excluding SEPA)
Full Requirements
PEF PR
HPS, 356
Interm. 2 - 150
PEF Interm. 3 - 150
Member Generation (excess)
Payne Creek Peaking, 310
Payne Creek CC, 572
Calpine, 360
SGS Unit 3, 750
LCRR/Telogia/BioEng
Unit 2 Lease/Own Option
Re-purchased 12/2005
Seminole Plant and CR3
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
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


Seminole Power Supply Resource Requirements
Winter Season (MW)
Based upon reserve spreadsheet (05BASEA2) dated 9/02/2005 (2005 Load Forecast) - 9 member
Hatched areas denote contract optionality
Total Seminole Load at the Generator
(Excluding SEPA)
Full Requirements
PEF PR
HPS, 356
Member Generation (excess)
Payne Creek Peaking, 310
Payne Creek CC, 572
Calpine, 360
SGS Unit 3, 750
LCRR/Telogia
/BioEng
Unit 2 Lease/Own Option
Re-purchased 12/2005
Seminole Plant and CR3
12000
10000
8000
6000
4000
2000
0
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 2031 2032 2033 2034

Summary of Bus Bar Costs

Levelized Costs for 2012 – 2031

		90% Capacity Factor		80% Capacity Factor		70% Capacity Factor	
Coal Alternatives	**MW**	**Nominal $/MWh**	**PW 2012 $/MWh**	**Nominal $/MWh**	**PW 2012 $/MWh**	**Nominal $/MWh**	**PW 2012 $/MWh**
Self Build	600	$51.29	$30.73	$54.10	$32.47	$57.71	$34.70
FMPA Joint Project	150	$52.84	$31.74	$56.28	$33.83	$63.70	$38.54
Invenergy	650	$58.41	$34.55	$62.23	$36.83	$70.70	$41.43
Longleaf/LS Power	400	$62.19	$36.95	$66.74	$39.68	$72.57	$43.18
Peabody	400	$62.85	$37.01	$69.08	$40.69	$77.10	$45.41
Gas Alternatives	**MW**	**Nominal $/MWh**	**PW 2012 $/MWh**	**Nominal $/MWh**	**PW 2012 $/MWh**	**Nominal $/MWh**	**PW 2012 $/MWh**
Self Build	500	$66.52	$38.50	$68.09	$39.47	$70.11	$40.73
Invenergy	516	$69.23	$39.68	$71.20	$40.84	$73.73	$42.33
Southern Co., Orange Cty	533	$72.32	$41.68	$74.30	$42.88	$77.33	$44.72
Southern Co., Orange Cty	553	$72.53	$41.60	$75.43	$43.23	$78.41	$44.98
Southern Co., Orange Cty	645	$71.83	$41.31	$73.56	$42.37	$75.93	$43.81
Southern Co., Orange Cty	645	$72.90	$41.69	$74.88	$42.86	$77.47	$44.39
Southern Co., St. Lucie Cty	533	$72.99	$42.13	$75.20	$43.48	$78.20	$45.30
Southern Co., St. Lucie Cty	533	$74.08	$42.52	$77.34	$44.35	$80.64	$46.30
Southern Co., St. Lucie Cty	645	$72.71	$41.85	$74.58	$43.00	$77.13	$44.55
Southern Co., St. Lucie Cty	645	$73.61	$42.18	$76.35	$43.72	$79.14	$45.37
Pasco Cogen	106	$83.14	$47.70	$85.41	$49.05	$88.59	$50.83

Present Worth Revenue Requirements (PWRR) Results

Updated Economic Analyses Based on 7/2005 Base Case Present Worth Revenue Requirements (PWRR) in 2005 $000 for 2006 – 2030			
Study Description by Base Load Unit	**Average Annual PWRR**	**Average Annual PWRR Cost/ (Savings)**	**Cumulative PWRR Cost/ (Savings)**
500 MW Self-build Gas-Fired Combined Cycle Unit	770,653	19,903	497,568
750 MW Self-build Coal Unit	750,751	--	--

Initial Economic Analyses Based on 12/2004 Base Case Present Worth Revenue Requirements (PWRR) in 2005 $000 for 2006 – 2030			
Study Description by Base Load Unit	**Average Annual PWRR**	**Average Annual PWRR Cost/ (Savings)**	**Cumulative PWRR Cost/ (Savings)**
600 MW Self-build Coal Unit and 150 MW FMPA Coal Unit	682,903	4,940	123,493
All Gas Self-build Scenario	701,952	23,988	599,705
600 MW Purchased Power Coal Unit and 150 MW FMPA Coal Unit	705,321	27,357	683,923
750 MW Self-build Coal Unit	677,964	--	--

Cumulative and Annual PWRR Results

Case Description:

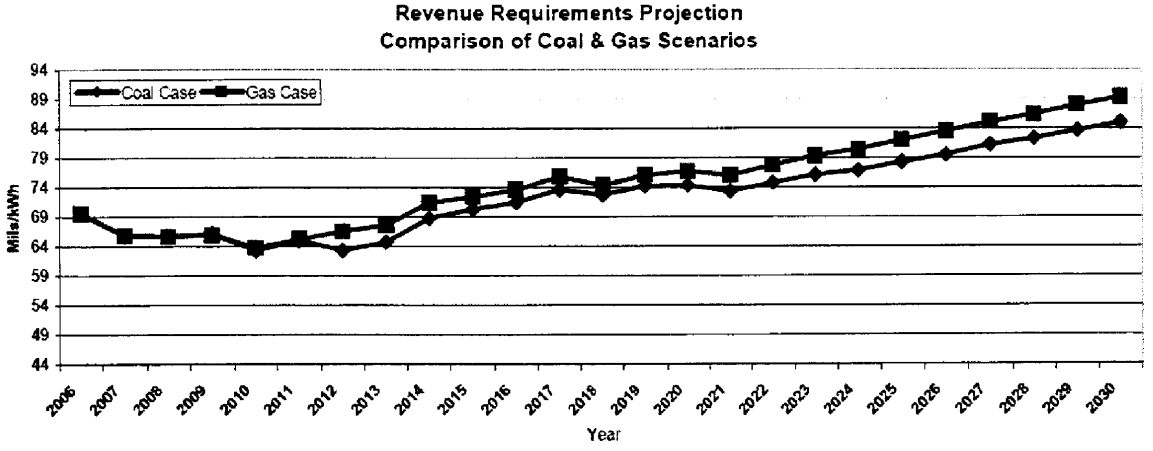
Comparison of Coal versus Gas Scenarios

Cumulative PWRR Savings = $497,568,000
Average Annual PWRR Savings = $19,903,000
Average Annual Nominal PR Savings = $49,878,000

Assumptions:

- 2005 Load Forecast
- Annual 2005 Fuel Price Forecast
- 7 Member Load Commitment after July 2020
- Reliant Peaking Extension
- Calpine CC Extension
- Term: 2006-2030

Seminole Electric Cooperative, Inc.



Year	Coal Case (05BASE41)	Gas Case (05SBCCA1)	Difference	Coal Case (05BASE41)	Gas Case (05SBCCA1)	Difference	PW Difference
2006	$69.50	$69.50	$0.00	$1,168,257,000	$1,168,321,000	$64,000	$60,377
2007	$65.80	$65.80	($0.00)	$1,155,427,000	$1,155,402,000	($25,000)	($22,250)
2008	$65.69	$65.64	($0.05)	$1,206,180,000	$1,205,245,000	($935,000)	($785,044)
2009	$66.16	$65.96	($0.20)	$1,262,822,000	$1,259,011,000	($3,811,000)	($3,018,669)
2010	$63.32	$63.73	$0.40	$1,258,799,000	$1,266,806,000	$8,007,000	$5,983,296
2011	$64.96	$65.26	$0.30	$1,340,497,000	$1,346,766,000	$6,269,000	$4,419,398
2012	$63.27	$66.56	$3.29	$1,358,947,000	$1,429,567,000	$70,620,000	$46,966,334
2013	$64.73	$67.60	$2.87	$1,439,463,000	$1,503,175,000	$63,712,000	$39,973,697
2014	$68.68	$71.42	$2.74	$1,584,450,000	$1,647,625,000	$63,175,000	$37,393,186
2015	$70.24	$72.46	$2.21	$1,679,262,000	$1,732,181,000	$52,919,000	$29,549,694
2016	$71.41	$73.54	$2.12	$1,770,919,000	$1,823,609,000	$52,690,000	$27,756,435
2017	$73.55	$75.85	$2.30	$1,881,348,000	$1,940,225,000	$58,877,000	$29,260,066
2018	$72.75	$74.33	$1.58	$1,923,229,000	$1,964,897,000	$41,668,000	$19,535,585
2019	$74.26	$76.09	$1.83	$2,028,180,000	$2,078,085,000	$49,905,000	$22,073,030
2020	$74.34	$76.70	$2.35	$1,730,659,000	$1,785,456,000	$54,797,000	$22,864,874
2021	$73.33	$76.05	$2.72	$1,239,041,000	$1,285,007,000	$45,966,000	$18,094,345
2022	$74.76	$77.77	$3.01	$1,304,996,000	$1,357,540,000	$52,544,000	$19,512,972
2023	$76.15	$79.32	$3.17	$1,372,889,000	$1,430,101,000	$57,212,000	$20,043,869
2024	$76.84	$80.41	$3.58	$1,433,886,000	$1,500,609,000	$66,723,000	$22,052,820
2025	$78.23	$82.01	$3.78	$1,503,487,000	$1,576,171,000	$72,684,000	$22,663,215
2026	$79.53	$83.51	$3.98	$1,576,782,000	$1,655,705,000	$78,923,000	$23,215,627
2027	$81.20	$85.07	$3.87	$1,660,251,000	$1,739,403,000	$79,152,000	$21,965,084
2028	$82.34	$86.35	$4.01	$1,740,119,000	$1,824,925,000	$84,806,000	$22,201,979
2029	$83.64	$87.94	$4.30	$1,817,863,000	$1,911,268,000	$93,405,000	$23,069,033
2030	$84.94	$89.30	$4.36	$1,902,617,000	$2,000,210,000	$97,593,000	$22,739,036
						$1,246,940,000	$497,567,990

Note: Discount rate is 6%