BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 120234-EI

PETITION TO DETERMINE NEED FOR POLK 2-5 COMBINED CYCLE CONVERSION, BY TAMPA ELECTRIC COMPANY.
_________________________________/

VOLUME 2
(Pages 184 through 354)

PROCEEDINGS: NEED DETERMINATION HEARING

COMMISSIONERS PARTICIPATING: CHAIRMAN RONALD A. BRISÉ
COMMISSIONER LISA POLAK EDGAR
COMMISSIONER ART GRAHAM
COMMISSIONER EDUARDO E. BALBIS
COMMISSIONER JULIE I. BROWN

DATE: Wednesday, December 12, 2012

TIME: Commenced 11:41 a.m.
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PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida

REPORTED BY: LINDA BOLES, CRR, RPR
Official FPSC Reporter
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APPEARANCES: (As heretofore noted)

I N D E X

WITNESSES

EXHIBITS

NUMBER:		ID.	ADMTD.
11			340
16			227
17			302
18			340
20	RFP	230	302
29	Need Study Table 13 and TECO's Answers to Staff's #38	277	302
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(* **REPORTER'S NOTE:** Exhibits 30 and 31 withdrawn.)

P R O C E E D I N G S

(Transcript continues in sequence from Volume 1.)

CHAIRMAN BRISÉ: All right. If -- everybody take about a minute to, to find a comfortable spot and we'll reconvene.

All right. TECO, call your next witness.

MR. BEASLEY: Mr. Chairman, as staff indicated earlier, our next witness, Mr. David M. Lukcic's testimony has been stipulated. At this time I'd ask that it be inserted into the record as though read.

CHAIRMAN BRISÉ: All right. We will enter his testimony into the record as though read.

MR. BEASLEY: Thank you. And he sponsors no exhibits, so we have no exhibit to worry about in that case.

CHAIRMAN BRISÉ: All right. Thank you.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

DAVID M. LUKCIC

Q. Please state your name, business address, occupation and employer.

A. My name is David M. Lukcic. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Manager Environmental Capital Projects in the Environmental Health and Safety Department.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor's of Science degree in Electrical Engineering from University of South Florida, and a Masters of Business Administration from University of South Florida. I am also a registered Professional Engineer in the State of Florida. I worked in Energy Delivery in Distribution Engineering and Standards for two years overseeing the design and implementation of our company's distribution design standards. In 2000, I was promoted to Manager of Land and Water Programs in Environmental Affairs. In 2003, I became Manager Environmental Capital Projects in Environmental Health and Safety. I have overseen the development, submittal, and permitting of Transmission Line Siting Act ("TSLA") and Power Plan Siting Act ("PPSA") projects over the last 12 years. This includes the Willow Oak - Wheeler - Davis and the Lake Angus - Gifford transmission siting's as well as the development and submittal of both integrated coal gasification combined cycle ("IGCC") and natural gas combined cycle ("NGCC") units.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to demonstrate, from an environmental perspective, the benefits of the proposed Polk 2-5 Combined Cycle Conversion over other alternatives Tampa Electric considered. I will describe the environmental requirements and permits necessary to comply with existing regulation. Finally, I will explain why the selection of NGCC technology is the best alternative to ensure the company meets or surpasses environmental requirements on emissions over other technologies.

Q. Are you sponsoring any sections of Tampa Electric's Determination of Need Study for Electrical Power: Polk 2-5 Combined Cycle Conversion ("Need Study")?

A. Yes. I sponsor sections of the Need Study entitled "Environmental". Specifically, I sponsor sections III.D "Environmental" and IX.C. "Environmental."

ENVIRONMENTAL BENEFITS OF POLK 2-5

Q. What are the environmental benefits of NGCC generation versus simple cycle combustion turbine ("CT") generation?

A. The conversion of the existing CTs to an NGCC unit is designed to take advantage of the waste heat from operation of the CTs that would otherwise be vented into the atmosphere. This waste heat is a valuable resource that can be used to generate up to 352 MW of electric power without any additional fuel input. The addition of heat recovery will make the efficiency of these generating units to increase by approximately 37 percent. The improvement in power generating efficiency results in a direct reduction in the emission rate for all pollutants on a pound per MWH basis and will also reduce CO_2, NO_x, and SO_x emission rates by approximately 37 percent.

The project will also include the installation of Selective Catalytic Reduction ("SCRs") equipment in each heat recovery steam generator ("HRSG") to reduce NO_x emissions. The SCRs in combination with cycle efficiency improvements will provide an 86 percent reduction in the NO_x emission rate.

Q. Are there any other environmental benefits specific to the Polk 2-5 conversion project?

A. Yes, the Polk Power Station site is already sited and zoned for power generation. This project takes advantage of significant existing infrastructure. The Polk Power Station site will also take advantage of an existing Reclaimed Water Supply Agreement with the City of Lakeland and Polk County that will provide for a majority of the water needed for the expansion. The project will utilize reclaimed water for the makeup to the cooling reservoir. Lakeland's Water Treatment Facility currently discharges its reclaimed water into the Alafia River which flows into Tampa Bay. Polk Power Station is taking this water from Lakeland and treating it removing any nutrients before discharging into Little Pane Creek which aids in improving the water quality in Tampa Bay. Using the treated water will minimize additional consumptive use withdrawals to the greatest extent possible and will assist in lessening the amount of nutrients flowing into Tampa Bay.

ENVIRONMENTAL APPROVALS AND REQUIREMENTS

Q. What type of permits will be required for Polk 2-5?

A. Polk 2-5 will require federal, state, and regional environmental approvals and permits. The principal approval is Certification under Florida's Electrical PPSA. This will include a comprehensive review of all environmental aspects of Polk 2-5, coordinated through the Florida Department of Environmental Protection ("FDEP") and will involve all state and regional agencies with environmental responsibility and those potentially affected by Polk 2-5.

Q. Please summarize the major requirements for the environmental approvals for Polk 2-5.

A. The environmental approvals required for the Polk 2-5 conversion will require the assembly of technical information on the physical equipment and operational parameters in addition to the environmental aspects of the future operations. The environmental regulatory agencies will evaluate the environmental impacts and/or improvements of the project against historical operations of the plant and alternate generation technologies. Based on this evaluation they will make a determination whether any operational restrictions are needed or if any additional pollution control equipment is needed for the Polk 2-5 conversion.

Q. What is the schedule for filing the required environmental permits?

A. We expect to file the Site Certification Application with the FDEP in September 2012.

Q. What general features of the Polk Power Station site serve to meet existing or potential environmental requirements?

A. The Polk Power Station site was selected because of the advantages of using the existing site and infrastructure which helps minimize environmental impacts. The Polk Power Station site includes sufficient land area, which has been previously certified in accordance with the PPSA. In addition, Polk Power Station has secured additional consumptive water from Reclaimed Water Use

Agreements with both the City of Lakeland and Polk County. These agreements will not only minimize additional groundwater withdrawals but will also remove nutrients from the reclaimed water before it is used for cooling water purposes and then returned to the environment.

Q. Will the proposed project comply with all local, state and federal environmental standards and requirements?

A. Yes, it will.

COMPLIANCE STRATEGY

Q. Will the emission rates of mercury from Polk 2-5 meet or be lower than regulatory standards?

A. The recently promulgated Mercury and Air Toxics Standards for mercury and other hazardous air pollutants do not apply to natural gas-fired units and there are no other mercury emission rate standards applicable to Polk 2-5. Mercury emissions from natural gas units are de minimis.

Q. What are the Mercury and Air Toxics ("MACT") standards for Electric Generating Units and how will they influence or impact Polk 2-5?

A. The MACT standards for Electric Generating Units are not applicable to natural gas units including Polk 2-5.

Q. How do the emissions of Polk 2-5 compare to those from units using coal generation technologies?

A. The emissions from Polk 2-5 are substantially lower than units using coal generation technologies. In fact, compared to super critical coal technology, NO_x SO_2, CO_2, emissions are lower by 90, 99, and 42 percent respectively, and Mercury levels are 99.9 percent lower utilizing the proposed combined cycle technology.

Q. How do the air emission rates for Polk 2-5 compare with recently proposed NGCC generation projects such as Florida Power & Light's ("FP&L") modernization of Port Everglades Plant?

A. Polk 2-5 will have similar emission rates to recently proposed NGCC projects such as FP&L's modernization of Port Everglades. This is demonstrated by a comparison of the most recently proposed projects in the state of Florida based on permit applications and proposed data.

Q. How will the emission rates proposed for Polk 2-5 affect air quality?

A. The emission rates will only minimally affect Florida's air quality. This owes largely to the fact that the bulk of the incremental generation will come from waste heat from natural gas combustion that is already occurring. Polk County and the entire air shed or geographical area associated with Polk 2-5 are classified as in attainment with all National Ambient Air Quality Standards. The emissions as a result of Polk 2-5 are not expected to change the attainment status of the area.

OTHER ENVIRONMENTAL CONSIDERATIONS

Q. Are there any environmental or permitting requirements associated with the proposed transmission line required for the Polk 2-5 project?

A. Yes. The associated transmission facilities will be permitted through the FDEP Site Certification process. The company does not anticipate any problems obtaining the necessary permitting as a majority of the route will be in either Tampa Electric owned land/easements or in road right-of-way. The preferred route also minimizes any environmental impact and is further described in the direct testimony of Tampa Electric witness S. Beth Young.

Q. Please summarize your direct testimony.

A. Polk 2-5 will utilize a proven technology that will not only meet, but will likely surpass existing environmental regulatory requirements. The selection of NGCC technology over other alternatives will minimize emissions while simultaneously providing cost-effective and reliable energy. This project takes advantage of the waste heat which will result in additional generation with minimal fuel addition therefore reducing emissions on a pound per MWH basis. The project will also take advantage of the existing site infrastructure and the water resources that exist at the current facility.

Q. Does this conclude your direct testimony?

A. Yes, it does.

MR. BEASLEY: And our next witness, we call Ms. S. Beth Young.

Whereupon,

S. BETH YOUNG

was called as a witness on behalf of Tampa Electric Company and, having been duly sworn, testified as follows:

DIRECT EXAMINATION

Q Ms. Young, you were in the room earlier and were sworn in; right?

A Yes, I was.

Q Thank you. Could you please state your name, your business address, your occupation, and your employer?

A Okay. My name is Beth Young. My business address is 702 North Franklin Street, Tampa, Florida. And I work for Tampa Electric and I'm the director of our Energy Control Center.

Q Ms. Young, did you prepare and submit in this proceeding prepared direct testimony of S. Beth Young filed on September 12th, 2012?

A Yes, I did.

Q Do you have any changes to your testimony?

A No, I do not.

Q If I were to ask you the questions in your direct testimony, would your answers be the same?

A Yes, they would.

MR. BEASLEY: I would ask that Ms. Young's testimony be inserted into the record as though read.

CHAIRMAN BRISÉ: At this time we will enter Ms. S. Beth Young's testimony into the record as though read.

MR. BEASLEY: Thank you.

BY MR. BEASLEY:

Q Did you also prepare an exhibit identified as SBY-1 that accompanied your prepared direct testimony?

A Yes, I did.

Q Do you have any changes to make to that exhibit?

A Yes, I do. In the process of doing, answering the interrogatories, determined that we had inadvertently left out one of the circuits, the re-rate on circuit 230605. And the dollars had been included but it had not been listed as a line item, and that was corrected on the second set of interrogatories, question number 44.

MR. BEASLEY: Thank you. I would ask that Ms. Young's exhibit be marked hearing Exhibit 16 as set forth in the exhibit list.

CHAIRMAN BRISÉ: All right. Thank you. We will do that.

MR. BEASLEY: Thank you.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

S. BETH YOUNG

Q. Please state your name, business address, occupation and employer.

A. My name is S. Beth Young. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Energy Control Center.

Q. Please provide a brief outline of your educational background and business experience.

A. I received my Bachelor's of Science in Electrical Engineering degree from the University of South Florida in 1983. I am a registered professional engineer in the state of Florida. I joined Tampa Electric as a co-operative education student in 1980 and became a full time employee as an associate engineer in 1983. From 1983 through 2007, I held various positions in Tampa Electric's Electric Delivery Department including System Operations, Substation Engineering, Lighting and

Standards. In 2007, I was promoted to Director, Substation Services and Project Management. In this position, I was responsible for the construction and maintenance of the substation facilities of Tampa Electric and the management of large Transmission and Distribution ("T&D") projects within Tampa Electric. In August 2009, I added Meter Services responsibilities which included meter specifications, testing, meter reading, and field credit. In February 2010, I was named Director, Energy Control Center. My present responsibilities include the areas of long-term transmission and distribution infrastructure planning day-to-day distribution outage restoration, transmission and distribution system operations, system dispatch operations, wholesale energy accounting and billing, transmission billing, system reliability tracking and reporting, construction and maintenance of Tampa Electric's lighting facilities and Energy Delivery emergency response and planning.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to describe how Tampa Electric determined the most cost-effective transmission plan for the interconnection and integration of Tampa Electric's proposed Polk 2-5 Combined Cycle ("Polk 2-5") Conversion project that meets both North American Electric Reliability Council ("NERC") and Florida Reliability Coordinating Council ("FRCC") reliability standards. I will discuss the overall transmission evaluation process Tampa Electric conducted including the stability and steady state power flow study results used in determining the most cost-effective manner to interconnect and integrate Polk 2-5 into the transmission system. Finally, I will discuss the estimated costs and construction schedule of the transmission system facilities required to interconnect and integrate Polk 2-5 into Tampa Electric's system.

Q. Have you prepared an exhibit to support your direct testimony?

A. Yes. I sponsor Exhibit No. ___ (SBY-1) that consists of four documents:

Document No. 1	Polk 2-5 CC Interconnection Diagram
Document No. 2	Polk 2-5 Integration Diagram
Document No. 3	Summary of Required Facilities, Ratings and Cost

Document No. 4 FRCC letter confirming the reliability of the interconnection and integration plan

Q. Are you sponsoring any sections of Tampa Electric's Determination of Need Study for Electrical Power: Polk 2-5 Combined Cycle Conversion ("Need Study")?

A. Yes. I sponsor section III.A.1. entitled "Transmission and Distribution" and section IX.D. entitled "Transmission Facilities".

Q. Please describe Tampa Electric's transmission system.

A. Tampa Electric's transmission system consists of approximately 1,300 miles of transmission lines and is operated at 3 different voltage levels; 69 kV, 138 kV, and 230 kV. Tampa Electric is interconnected to four other balancing areas through twenty-seven tie lines.

Q. Please describe Tampa Electric's evaluation process that results in determining the most cost-effective transmission system requirements for new generation resources.

A. Tampa Electric's process begins with evaluating the proposed generating plant site location to determine its proximity to existing transmission facilities. To the extent there are existing transmission facilities nearby, the site is then assessed to determine its capability for reliably interconnecting and integrating the proposed new generation into the transmission system as a firm Tampa Electric network resource.

Q. What factors are considered when integrating the proposed new generation into the transmission system?

A. There are numerous factors that are considered prior to integration of a new generating unit into the bulk electric system ("BES"). They include:

- The megawatt ("MW") amount of generation being added at the generation site and various dispatch profiles of the new generation resource relative to existing generation resources serving Tampa Electric and others utilities' load in the region;
- Compliance with NERC and FRCC reliability standards;
- Stability and system protection impacts;
- Impact on existing Tampa Electric or third party facilities;

- Capability to upgrade existing substation or transmission facilities;
- Ability to site new substation or transmission line facilities including right-of-way requirements, existing right-of-way capabilities, permitting requirements, and expected time frame to acquire right-of-way and necessary permits;
- Ability to construct the required transmission facilities without having to take outages on existing operating facilities during periods that would result in an adverse reliability impact;
- Operating considerations such as maintenance requirements of the proposed interconnection and integration facilities and impacts to the ongoing operation of the system;
- The timing and amount of power needed for testing equipment such as pumps and motors;
- Expected in-service testing and commercial operation dates for new generation, which determines the date transmission interconnection and integration facilities must be completed for the unit's testing; and
- The initial and ongoing costs of facilities and operations.

Q. How did Tampa Electric evaluate the impact of the Polk 2-5 generation addition on the Bulk Electric System?

A. A Network Resource Interconnect Study ("NRIS") was used to evaluate the impact of the generation addition on Florida's BES. The NRIS included a review of stability requirements, short circuit impacts and steady state requirements in compliance with NERC and FRCC reliability standards. These power flow studies were used to evaluate the performance of the transmission system and to determine various project alternatives that would be needed to interconnect and integrate the new generation into the BES.

Q. How were project alternatives for adding or upgrading transmission facilities developed?

A. A Tampa Electric core team developed and reviewed potential alternatives and estimated costs. This core team was comprised of engineers from System Planning, Environmental, Health and Safety, Substation Engineering, Transmission Engineering, Telecommunications, System Security and staff from Line Clearance, Real Estate, Project Management, and Community Relations. As part of their analysis, this team considered the issues outlined previously, including ability to construct, potential upgrade of existing facilities, right-of-way requirements, in-service dates and operating considerations. When the core team was satisfied that they had developed the most cost-effective transmission interconnection and integration plan that complied with NERC and FRCC reliability standards, the process was deemed complete.

Q. How is the Polk Power Station connected to the BES?

A. The Polk Power Station is interconnected to the BES through the Polk Power Substation. [redacted]

Q. What were the results of the stability, short circuit and power flow studies that Tampa Electric performed?

A. The stability studies did not show any adverse impacts to the BES by the addition of the Polk 2-5. The Short circuit study showed that 16-230 kV circuit breakers located at Polk Power, Pebbledale, Mines and Big Bend Power Substations did not meet the interrupting capability required due to the addition of Polk 2-5.

The results of the power flow studies determined under certain dispatches an overload might occur on the following facilities:

1. The 230 kV transmission line from Polk Power Substation to Mines Substation,
2. The 230 kV transmission line from Pebbledale Substation to FishHawk Substation,
3. The two 230 kV transmission lines from Polk Power Substation to Pebbledale Substation,
4. Some additional 3rd parties' transmission facilities.

These results indicated that, under extreme conditions, there might not be enough transmission capability out of Polk Power Substation to transmit the entire plant's capacity. After considering these potential impacts, the core team set about to consider various alternatives to insure continuing BES reliability.

Q. What projects did the core team recommend after reviewing the power flow study results?

A. The core team recommended the following projects in order to maintain the BES reliability:

1. Build a new 230 kV transmission switching station (Aspen Substation) west of Mines Substation.
2. Build the following 230 kV transmission lines
   - Polk Power Substation to Mines Substation,
   - Mines Substation to Aspen Substation,
   - Two lines from Aspen Substation to FishHawk Substation.
3. Upgrade segments of existing 230 kV transmission lines to create a 230 kV transmission line from Polk Power Substation to Aspen Substation.
4. Interconnect and rerate existing 230 kV transmission line from Big Bend Power Substation to Mines Substation into Aspen Substation.
5. Upgrade 16-230 kV circuit breakers at Polk Power Substation, Pebbledale Substation, Mines Substation and Big Bend Power Substation.
6. Reroute and upgrade the first Polk Power Substation to Pebbledale Substation 230 kV transmission line.
7. Rerate the second Polk Power Substation to Pebbledale Substation 230 kV transmission line.
8. Install a switched reactor at Davis Substation.
9. Upgrade the bus for the State Road 60 North 230/69 kV Transformer.

10. Upgrade the bus and low side circuit breaker for the Dale Mabry West 230/69 kV Transformer.

DESCRIPTION OF PLANNED PROJECT

Q. Please provide a general description of the existing transmission facilities at Polk Power Station.

A. As I previously stated, the Polk Power Substation is connected to the BES by four 230 kV transmission lines. Two of these lines run from Polk Power Substation to the Tampa Electric Pebbledale Substation. The third line runs from Polk Power Substation to Tampa Electric's Mines Substation and the fourth from Polk Power Substation to Invenergy's Hardee Station.

Q. Please provide a general description of the transmission facilities required for interconnection and integration of Polk 2-5 to Tampa Electric's system.

A. Two new 230 kV transmission circuits, three new 230 kV circuit breakers and a generator step-up transformer will be required to interconnect the new generation to the Polk Power Substation. As previously stated, one new switching substation, four new 230 kV transmission lines and upgrades to four other 230 kV transmission lines will be required to integrate Polk 2-5 into the BES. In addition, sixteen circuit breakers will need to be upgraded, some buswork and a 69 kV circuit breaker upgraded and a switched reactor added.

Q. Has the route for the four new 230 kV transmission lines been selected?

A. Yes. A route study was initiated in December 2011 and completed on July 27 2012. The route study identified the most cost-effective corridor Tampa Electric should utilize for the four new 230 kV transmission lines necessary as part of the Polk 2-5 project. Tampa Electric expects approval from the Florida Department of Environmental Protection of the corridor in the fourth quarter of 2013.

Q. How did Tampa Electric evaluate the transmission related costs associated with the planned Polk 2-5?

A. An estimating team made up of members from Substation Engineering, Transmission Engineering, Real Estate, System Security, Telecommunications, Line Clearance, Community Relations, Project Management, and Environmental Health and Safety reviewed the transmission interconnection and integration requirements to develop a scope of work. This included the review of existing drawings and site visits. Each member, along with an engineering consulting firm, then estimated the costs to complete their scope of work. As stated previously, the final corridor for the four new 230 kV transmission lines was not selected until July 27, 2012; therefore, the transmission line costs were based on one of the potential routes. The potential route used in the evaluation was approximately 4 miles longer than the route determined to be the most cost-effective in the completed route study.

Q. What is the total cost of the transmission interconnection and integration costs for Polk 2-5?

A. The total estimated project cost is approximately $147.2 million. A summary of the facilities required and associated costs is provided in Document No. 3 of my exhibit. Utilizing the updated information from the aforementioned route study completed on July 27, 2012, project costs would decrease as compared to those used in the project estimate, but these costs have not been finalized.

Q. What is the schedule for construction of the transmission facilities needed for the interconnection and integration of Polk 2-5?

A. The Polk 2-5 interconnection/integration work is scheduled to begin January 2013 and is estimated to be completed by November 2016. This will allow time for testing of the unit and associated NGCC equipment prior to its commercial in-service date. The Polk Power Substation to Aspen Substation to FishHawk Substation transmission line construction will begin by October 2014 with an in-service date of November 2016. The remainder of the work will be completed prior to November 2016. This ensures that all transmission facilities will be in-service prior to any full power testing of Polk 2-5.

Q. Has this assessment, along with the Polk 2-5 interconnection and integration requirements discussed above, been reviewed by the FRCC?

A. Yes. According to the FRCC's Regional Transmission Planning Process, Tampa Electric's interconnection and integration plan for Polk 2-5 as discussed above was provided to the FRCC for review and affirmation was given that no reliability issues exist. A letter from the

FRCC confirming the reliability of Tampa Electric's interconnection and integration plan is provided in Document No. 4 of my exhibit.

Q. What were the FRCC conclusions about Tampa Electric's Polk 2-5 transmission plan?

A. Based on the review and analysis conducted by the Transmission Working Group, the FRCC Planning Committee has determined that the proposed interconnection and integration plan will be reliable and will not adversely impact the reliability of the FRCC transmission system.

TRANSMISSION RELIABILITY BENEFITS OF POLK 2-5

Q. How will Polk 2-5 and its associated transmission facilities improve Tampa Electric's transmission reliability to Tampa Electric customers?

A. In addition to integrating the Polk 2-5 generation reliably into the BES, the new transmission facilities will also increase the import and export capability of the Tampa Electric transmission system. This provides more source options during planned and unplanned generation outages. The upgrades of the existing 230 kV facilities will also reduce the existing exposure to multi-circuit structure outages, increasing the reliability of the transmission system.

The addition of the new transmission facilities in the Central Florida region of the BES will also improve the reliability of that region for Tampa Electric customers as well as for those in the FRCC region.

Q. Please summarize your direct testimony.

A. Tampa Electric has completed stability, short circuit and power flow studies to determine the impact of the interconnection and integration of Polk 2-5 to the BES. The studies indicate two new 230 kV transmission circuits, three new 230 kV circuit breakers and a generator step-up transformer will be required to interconnect the new generation to the Polk Power Substation. In addition one new switching substation, four new 230 kV transmission lines and upgrades to other 230 kV transmission lines will be required to integrate Polk 2-5 into the BES. Sixteen circuit breakers, some buswork and a 69 kV circuit breaker will also need to be upgraded as well as the addition of a switched reactor.

These additions will reliably interconnect and integrate the Polk 2-5 into the BES. In addition, Tampa Electric customers will benefit by the increased import and export capability, reduced exposure to multi-circuit structure outages and improved reliability for the Central Florida region.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BY MR. BEASLEY:

Q Ms. Young, could you please summarize your direct testimony?

A I can. Good morning, Commissioners. My direct testimony addresses the transmission facilities required to interconnect and integrate the Polk 2-5 conversion.

Tampa Electric performed a stability, a short circuit, and a power flow study to determine the impact of the Polk 2-5 on the bulk electric system, and to determine what transmission facilities would need to be required in order to reliably interconnect.

FRCC also evaluated the Polk 2-5 combined cycle and the associated transmission facilities that Tampa Electric put forward to ensure, and concluded that it was reliable and would not adversely impact the FRCC transmission system.

The projects required to interconnect the new generation at the Polk Power Substation include two new 230kV lines and three new 230kV breakers. The major components to integrate the -- excuse me. The major components required to integrate the Polk 2-5 combined cycle are one new switching substation, four new 230kV lines 35 miles in length, and upgrades to four other 230kV lines. The total cost for the project is

$147.2 million.

In addition to reliable operation of the Polk 2-5 combined cycle conversion, Tampa Electric customers will benefit by the increased import and export capability, reduced exposure to multi-circuit structure outages, and improved reliability for the Central Florida region. That concludes my summary.

MR. BEASLEY: Thank you. We tender Ms. Young for questions.

CHAIRMAN BRISÉ: Thank you.

Mr. Wright?

MR. WRIGHT: Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MR. WRIGHT:

Q Good morning, Ms. Young.

A Good morning.

Q I don't have a lot of questions for you today. I'm sure you'll be happy to hear that.

A Thank you.

Q Was your role in this case pretty much limited to, to the transmission analyses that are shown in your, in your exhibit?

A Yes, it was.

Q Thank you. Reading your testimony, you evaluated transmission costs including upgrades and integration costs for the Polk project; correct?

A That is correct.

Q And it appears, from reading your testimony, that, that Tampa Electric had a team that evaluated various alternatives for meeting those, the transmission requirements necessary to integrate the Polk project into the company's system so that its power could be delivered throughout the system; correct?

A That's correct.

Q It's a pretty -- it sounded like a pretty good sized team; is that fair?

A That is correct.

Q About how many people were on it?

A I would say probably about eight, eight to ten.

Q And did I understand your testimony to indicate that, that throughout the process you identified options, then identified additional options, and continued to evaluate options for integrating the trans -- the Polk system -- Polk project into your system?

A Yes. The -- to start off with, the planning team evaluated different options for different alternatives. And then this larger team looked at those alternatives on a broader scale, and then we started narrowing down to the best alternative.

Q Okay. At some point you got to a basic proposed, basic conceptual transmission plan. And then was it at that point that you ran the power flow studies that are referenced on page 9?

A We ran some basic power flow studies on the alternatives we were looking at originally just to see if they were viable. But the detailed power flow studies were right on that final.

Q And then when you ran, at some point you ran some power flow studies that identified some additional contingencies that required some additional measures to be taken in terms of constructing or configuring the upgraded transmission system; correct?

A That is correct.

Q And that's -- we don't have to walk through all of them, but that's what's identified, the overloads are identified on page 9 of your testimony and the recommended fixes are identified on pages 10 and 11 of your testimony; correct?

A That is correct. Yes.

Q Okay. About how much time did your team work on, on this project in, both in calendar time and person hours, if, if you can help me out there?

A As far as calendar time, we had done some preliminary looks at the end of 2011. And as far as detailed study time, the detailed studies were probably from January until I believe April or May.

Q Just ball parking it, would it be fair to say that there was like, you know, one or two full-time equivalent people working on this project during that time period, or more than that, less?

A For that time period there's probably about between one and two full man people doing the study.

Q Thank you.

A Uh-huh.

Q As part of your work with relation to the, to the Polk project and this need determination proceeding, did you also evaluate transmission costs for any of the power supply proposals that were offered to Tampa Electric in the RFP project -- process?

A We were asked to develop an integration cost for the RFP bids.

Q Okay. And Mr. Taylor's exhibit shows, I think it's, I think it's Table A4, although it might be A5.

A I believe it's A4.

Q Yeah. It shows the, the integration costs; correct?

A That is correct.

Q And did you furnish those, those, those costs to Mr. Taylor?

A Yes.

Q And then there's also Table A5, which identifies the wheeling charges for the various proposals; correct?

A Yes. I believe that's correct. Yes.

Q Did you furnish that information to Mr. Taylor?

A No, I did not.

Q Just given your extreme knowledge regarding transmission, I'm going to ask you, do you know who did furnish that information to Mr. Taylor?

A This is public information. It's posted on the OASIS.

Q Okay.

A So my assumption is he went to that location or someone else within the company provided that information for him.

Q And that would be a charge in dollars per kW per month multiplied times the wattage times the years?

A Uh-huh. Yes.

Q Okay. Thank you. Did you, in the course of your work relative to this process in this proceeding, did you evaluate any alternative transmission arrangements for getting power from any of the bidders to Tampa Electric Company?

A I'm not sure what you mean by alternatives.

Q Well, Mr. Taylor assumed wheeling on FPL's system. Did you consider or were you asked to evaluate the possibility of building a transmission line from DeSoto to an interconnection with Tampa Electric in lieu of wheeling costs?

A No, we did not.

Q Thank you.

A I was not requested to do that.

Q Thanks.

MR. WRIGHT: Mr. Chairman, this does not need to be marked as an exhibit, but I would like to have it distributed so that everybody will have a copy in front of them. It is page 49 from the company's need study.

CHAIRMAN BRISÉ: Sure.

BY MR. WRIGHT:

Q Have you seen this before?

A I believe, yes, I've glanced at it before. Yes.

Q And generally speaking, what this shows is, is five different portfolios or five different generation expansion scenarios that Tampa Electric considered in the course of this process; correct?

A Yes.

Q And the first one is the Polk conversion project, Polk 2-5; correct?

A Yes.

Q And then the others are what they are so that for Proposal A the scenario would be adding Proposal A in 2017, then a CT in 2019, a CT in 2022, and so on; correct?

A Correct.

Q Okay. I've got just a couple of questions for you here. With respect to the future Tampa Electric units shown in, in the different scenarios, say, for example, the 2019 7FA CT that's shown in, in the Polk 2-5 column and the Proposal A column, did you provide transmission upgrade cost information to either Mr. Rocha or Mr. Taylor in connection with their evaluations of those scenarios?

A I did not for these. If you -- no.

Q Okay. Thanks.

Would that, would that hold true across all of the different proposals, Polk and then A, B, C, and D?

A We had provided integration costs for the Polk 2-5. And also, if you refer to our Ten-Year Site Plan, for the first 7FA in 2019 there are no additional transmission costs. We didn't do something further.

Q I'm sorry?

A We did not do -- we didn't provide any other additional costs for these other 7FAs.

MR. WRIGHT: Thank you. Thanks. That's all the questions I have. Thank you for coming.

CHAIRMAN BRISÉ: Ms. Christensen?

MS. CHRISTENSEN: No questions.

CHAIRMAN BRISÉ: Staff?

MS. BROWN: Staff has no questions at this time.

CHAIRMAN BRISÉ: Okay. Commissioners?

All right. Redirect?

MR. BEASLEY: Very brief redirect.

REDIRECT EXAMINATION

BY MR. BEASLEY:

Q Ms. Young, with respect to getting the power from the various bidders to the Tampa Electric system, do you know if the output of the DeSoto power station could be brought to the Tampa Electric system with the current transmission system?

A Not on a firm basis under all conditions, no.

Q What would be required in order for that to happen?

A In order to do it on a firm basis you would have to do upgrade on two 230kV circuits on Tampa Electric's system and upgrade on about ten miles of line in Florida Power & Light's system.

Q Do you know if in addition to that any wheeling charges would apply?

A There would also need to be wheeling charges because DeSoto plant is located in FP&L's transmission. And in order to wheel the power up to Tampa Electric and to meet the need of our customers, we'd have to pay wheeling charges to have that power wheeled through Florida Power & Light's transmission system.

Q So your company would pay Florida Power & Light wheeling charges.

A That is correct.

MR. BEASLEY: Thank you. We have no further questions.

I'd like to move Exhibit 16, if I could.

CHAIRMAN BRISÉ: At this time we will move Exhibit 16 into the record.

(Exhibit 16 admitted into the record.)

All right. I think that was all the exhibits that were presented for this witness. Thank you very much for your testimony.

Just so that you are aware, we're going to try to work through lunch today, so we're going to just keep on rolling. Okay?

Call your next witness.

MR. WAHLEN: Very well. Mr. Chairman, Tampa Electric Company calls R. James Rocha to the stand, please.

Whereupon,

R. JAMES ROCHA

was called as a witness on behalf of Tampa Electric Company and, having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. WAHLEN:

Q Mr. Rocha, were you sworn in earlier this morning?

A I was.

Q Thank you. Would you please state your name, your business address, occupation, and employer?

A My name is Jim Rocha. I work for Tampa Electric Company at 72 North Franklin Street.

Q And what is your occupation?

A Oh, I'm the Director of the Planning, Strategy, and Compliance Department.

Q Very good. Did you prepare and submit in this proceeding prepared direct testimony of R. James Rocha filed on September 12th, 2012?

A I did.

Q And did you sponsor revisions to your testimony that were filed on October 12th, November 20th, and November 27th?

A I did.

Q With those revisions, if I were to ask you the same questions contained in your direct testimony, would your answers be the ones contained in your revised direct testimony?

A Yes, they would.

MR. WAHLEN: Mr. Chairman, we'd ask that the revised prepared direct testimony of Mr. Rocha be inserted into the record as though read.

CHAIRMAN BRISÉ: At this time we'll enter the revised direct testimony of Mr. James Rocha into the record as though read.

MR. WAHLEN: Thank you very much.

BY MR. BEASLEY:

Q Did you also prepare the exhibit identified as RJR-1 that accompanied your direct testimony?

A Yes, I did.

Q Did you sponsor the revisions to your exhibits that were filed on October 12th, November 20th, and November 27th?

A Yes.

MR. WAHLEN: Very well. Mr. Chairman, I believe that that exhibit has been premarked as Exhibit

Number 17, and we'd ask that it be formally identified at this time.

CHAIRMAN BRISÉ: Sure. We want to identify Exhibit Number 17 representing RJR-1.

MR. WAHLEN: Thank you very much.

BY MR. WAHLEN:

Q Mr. Rocha, are you also familiar with the document that has been premarked as Exhibit 20? I believe that's the -- are you familiar with that one?

A Yes, I am.

Q And is that the company's RFP that was used in this case?

A Yes, it is.

MR. WAHLEN: Okay. Mr. Chairman, we'd also ask that the company's RFP be formally identified as Exhibit 20.

CHAIRMAN BRISÉ: Okay. We will identify for marking purposes Exhibit 20 as the RFP.

(Exhibit 20 marked for identification.)

BY MR. WAHLEN:

Q Okay. Mr. Rocha, you also sponsor portions of Exhibit 11, which is the need study; is that correct?

A Yes.

Q And do you have a correction or update to Exhibit 11, which is the need study?

A Yes, I do.

Q And could you please point that out to the Commission and explain what the change is?

A Okay. On page 61 of the need study, a, on Table 13, there's a table on Proposal B. There's a line item that's a typo in putting things into the Word document, and the number currently is 13602.5 and should have been 13937.1. The total is correct and the delta is correct. It was a typo on that line item.

Q Okay. Thank you very much. Any other changes or corrections?

A No, I do not.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

R. JAMES ROCHA

Q. Please state your name, business address, occupation and employer.

A. My name is R. James Rocha. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director of Planning, Strategy & Compliance. I direct the resource planning group where my responsibilities include identifying the need for future resource additions as well as analyzing the economic and other operational impacts to Tampa Electric's system associated with the addition of resource options.

Q. Please provide a brief outline of your educational background and business experience.

A. I graduated from the Georgia Institute of Technology with a Bachelor of Nuclear Engineering degree in 1982 and a Master of Science Degree in Nuclear Engineering in 1983. I earned a Master's degree in Business Administration from the

University of Tampa in 1993 and I am a registered Professional Engineer in the State of Florida. In 1984, I was employed by Commonwealth Edison Company as a nuclear fuel engineer, modeling unit operation. In 1987, I joined Florida Power, and became a resource planning engineer in the Generation Planning department. In 2000, I became Manager of Financial Analysis at TECO Energy, responsible for business development and asset management. Since 2006, I have held several positions at Tampa Electric responsible for budgeting, business strategies and North American Electric Reliability Corporation ("NERC") Critical Infrastructure Protection ("CIP") and non-CIP NERC compliance. I have 28 years of accumulated electric utility experience working in the areas of resource planning, business and financial analysis, and engineering. In December 2011, I was appointed to my current position.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to describe Tampa Electric's integrated resource planning ("IRP") process and the resulting resource plan which supports the 2017 need for the Polk 2-5 combined cycle conversion project ("Polk 2-5"), a natural gas combined cycle ("NGCC") unit rated at 459 MW summer and 463 MW winter net incremental capacity, respectively. My direct testimony will (1) describe Tampa Electric's existing system and resource mix, (2) describe Tampa Electric's IRP process for selection of future demand and supply resource alternatives, (3) demonstrate that Polk 2-5 is the most cost-effective alternative to reliably meet Tampa Electric's customer needs, (4) describe the need for additional resources for the Florida Reliability Coordinating Council ("FRCC") region, (5) describe the results of the RFP analysis, and (6) explain the adverse consequences if Polk 2-5 is deferred or denied.

Q. Have you prepared an exhibit to support your direct testimony?

A. Yes, Exhibit No. _____ (RJR-1) was prepared under my direction and supervision. It consists of the following thirteen documents:

Document No. 1 Energy Mix by Fuel Type
Document No. 2 Capacity Mix by Fuel Type
Document No. 3 Levelized Cost Screening Curves
Document No. 4 Tampa Electric Reliability Analysis
Document No. 5 FRCC Reliability Analysis
Document No. 6 FRCC Reliability Sensitivity Analysis
Document No. 7 Preliminary Resource Plans & Analysis
Document No. 8 IRP Resource Plans & Analysis

Document No. 9 IRP Sensitivity Analysis
Document No. 10 RFP Summary of Proposals
Document No. 11 RFP Resource Plans & Analysis
Document No. 12 RFP Qualitative Factors
Document No. 13 June 2012 Assumptions Update

Q. Are you sponsoring any sections of Tampa Electric's Determination of Need Study for Electrical Power: Polk 2-5 Combined Cycle Conversion ("Need Study")?

A. Yes. I am sponsoring the following sections of the Need Study: I. "Executive Summary", II. "Introduction and Overview", III.A. "Description of Tampa Electric's System", (except for III.A.1 and III.A.3), III.F.2. "Supply Technologies", IV. "Need for Capacity in 2017" (except for IV.A.1.), V. "Screening of Potential Technologies", VI. "Detailed Economic Analysis", VII. "Sensitivity Analysis", VIII RFP for Capacity as per Bid Rule, X. "June 2012 Assumptions Update", XI. "Adverse Consequences if Polk 2-5 is Delayed or Denied" and XII. "Conclusion".

DESCRIPTION OF EXISTING SYSTEM AND RESOURCE MIX

Q. Please describe Tampa Electric's service area.

for Tampa Electric spans approximately 2,000 square miles and consists of Hillsborough County, western Polk County and parts of Pasco and Pinellas counties. Tampa Electric served approximately 676,000 customers in 2011.

Q. What types of units make up Tampa Electric's existing generating system?

A. Tampa Electric has three large generating stations and one peaking station including an integrated gasification combined cycle ("IGCC") and steam coal base load units, NGCC intermediate load units, natural gas and oil fueled combustion turbine units, aero-derivative engine peaking units, and oil fueled internal combustion peaking units. The total net system generating capacity in winter 2011 was 4,684 MW and 4,292 MW in summer 2012. Tampa Electric operates 670 MW of winter net generating capacity that has dual fuel capability which improves overall system reliability.

Big Bend Power Station includes four pulverized coal-fired steam units and one aero-derivative peaking unit. Big Bend Units 1 through 4 are coal units that were retrofitted between 2007 and 2010 with additional environmental control systems including selective catalytic reduction ("SCR") to reduce nitrogen oxides ("NO_X") emissions to complete the station's comprehensive air emissions reduction program. Big Bend Combustion Turbine ("CT") 4 is a dual fuel (natural gas or oil) unit that is quick-start (full load in less than 15 minutes) and could provide black-start capability (a generating unit capable of starting from a shutdown condition without assistance from the electric system) for the station and the system.

H. L. Culbreath Bayside Power Station ("Bayside Power Station") includes two NGCC units and four aero-derivative peaking units. Bayside Unit 1 utilizes three combustion turbines, three heat recovery steam generators ("HRSG") and one steam turbine. Bayside Unit 2 utilizes four combustion turbines, four HRSGs and one steam turbine. Bayside Units 3 through 6 are natural gas-fired aero-derivative peaking units that are quick-start and provide black start capability for the station and the system.

Polk Power Station includes one base load and four peak load generating units. Polk Unit 1 is a dual fuel IGCC unit primarily fired with synthesis gas produced from a blend of low-sulfur coal and petroleum coke ("petcoke"). Distillate oil is a secondary fuel which is used for both start-up and shut-down of the power block, and can be used to operate the combined cycle at times when the gasification system is unavailable. Polk Units 2 through 5 are simple cycle CTs primarily fired by natural gas, and Units 2 and 3 are capable of firing distillate oil as a secondary fuel.

J. H. Phillips Sebring Power Station includes two diesel oil-fired peaking units located in Sebring, Florida. These two units were placed on long-term reserve stand-by ("LTRS") status on September 4, 2009 due to the relative higher cost of heavy oil compared to natural gas and coal. These units will remain on LTRS until the operating costs are competitive with other supply resources. These units also have the potential to utilize liquid biofuels and operate as a renewable energy resource in the future.

Q. Does Tampa Electric include any purchased power in its total supply resource mix?

A. Yes. Tampa Electric purchases power, both firm and non-firm, from other utilities and independent power producers operating in the Florida market. In 2011, Tampa Electric solicited the market for firm peaking power through the end of 2016 to replace the 20-year Hardee Power station purchase power agreement ("PPA") expiring December 31, 2012. Two PPAs were executed in fall 2011 for peaking capacity from the Florida market. These agreements are described in more detail in section III.A.2. of the Need Study. Only firm purchased power capacity is included in the reliability assessment process to determine the timing and minimum amount of new resources required to maintain the firm reserve planning criteria. However, both firm and non-firm purchased power energy is included in the production cost analyses to determine the most cost-effective mix of resources needed.

Q. What is the expected energy and capacity mix by fuel type for Tampa Electric's total supply resources including purchases in 2017?

A. The energy mix by fuel type for 2011 was 56 percent solid fuel, 43 percent natural gas, a slight amount of oil and 1 percent net interchange purchases on an energy (MWH) basis. In 2017, the energy mix is expected to be 59 percent solid fuel, 39 percent natural gas, a slight amount of oil and 2 percent net interchange purchases on the same basis. This is reflected in Document No. 1 of my exhibit. The capacity mix by fuel type for 2011 was 36 percent solid fuel and 64 percent natural gas on a capacity (MW) basis. In 2017, the capacity mix is expected to be 36 percent solid fuel and 64 percent natural gas on a capacity (MW) basis. This is reflected in Document No. 2 of my exhibit.

Q. Has Tampa Electric developed and implemented demand and energy reduction programs in its existing resource mix?

A. Yes. As described in Section III.A.3. of the Need Study, Tampa Electric has successfully developed and implemented numerous demand reduction and energy conservation programs for over 30 years. The cumulative effect of these programs as of the end of 2011 has eliminated the need for 719 MW in the winter and 306 MW in the summer of net generating capacity by slowing growth in both the company's peak demand and energy requirements. This reduction is roughly equivalent to the combined winter net capacity of Big Bend Units 1 and 2, and by 2017 the cumulative effect of these programs will eliminate the need for more than 376 MW of net summer generating capacity. As a percentage of the Tampa Electric total peak demand, this represents 9.0 percent of the planned total summer peak of 4,165 MW in 2017, higher than any NERC region average for demand reduction. Tampa Electric witness Howard T. Bryant describes the company's demand-side management ("DSM") achievements in his direct testimony.

INTEGRATED RESOURCE PLANNING PROCESS OVERVIEW

Q. What are the objectives of Tampa Electric's IRP process?

A. Tampa Electric's IRP process determines the timing, amount and type of additional demand reduction, energy conservation, and supply resources required to maintain system reliability in a cost-effective manner. The process considers the existing customer demand and energy mix, expected growth and changes in the customer demand and energy requirements, existing and future DSM and energy conservation programs, supply resources comprised of the Tampa Electric generating units and purchased power, existing and future bulk transmission system for Tampa Electric and the Florida grid, and potential renewable energy resources appropriate for the Florida energy market.

Q. Please describe Tampa Electric's IRP process.

A. The IRP process balances existing and future demand and supply resources in a reliable and cost-effective manner while considering strategic factors. Since cost-effectiveness is a requirement for both demand and supply resources, the process is an iterative cycle to capture the value of deferring new generating units or PPAs resulting from additional DSM programs. A reference resource plan that includes both demand and supply resources is developed which then becomes the basis for determining the new avoided costs for deferral of supply resources. The additional cost-effective DSM resources are then implemented to establish the system demand and energy requirement, which is the new basis for consideration of supply resource additions. The cycle is repeated annually each business planning cycle, as all of the operating and financial assumptions are updated.

The supply resources are initially screened on a levelized cost basis with several criteria: construction costs, operating and maintenance costs, technology viability or applicability to the operating region, commercial availability, and construction lead times. Multiple resource plans are developed that consist of various combinations of technologies and in-service dates to maintain system reliability. The relative impacts of each resource expansion plan are evaluated for total system annual operating and maintenance costs and incremental capital costs. This includes fuel, fixed and variable O&M, purchased power capacity, energy and transmission wheeling and/or transmission construction costs, and the incremental costs to build all new generating units and associated transmission capacity in each expansion plan. The plans are then initially ranked based on the lowest cumulative present worth revenue requirements ("CPWRR") of the system over a 30-year operating period.

The highest ranked resource plan incorporates an initial demand and energy forecast including DSM and supply resources. The supply resources in the reference resource plan are then used to determine the avoided cost for an economic analysis of additional viable DSM and conservation programs.

Next, the cost-effective DSM programs are included in a revised demand and energy forecast which effectively reduces system peaks and energy requirements. The revised system demand and energy forecast is used in a final reliability analysis to determine the new timing and magnitude of additional supply resources needed to meet system reliability criteria.

Final economic evaluations and sensitivities are performed to determine the recommended resource plan. The highest ranked plans are evaluated under various sensitivities to test key planning assumptions and compare the relative cost impact on a CPWRR basis. Strategic factors such as system and FRCC region reliability, resource dispatchability, system and FRCC deliverability, constructability (lead time, available technology, etc.), fuel diversity and environmental impacts are considered in determining the most cost-effective and viable resource mix for both Tampa Electric's customers and

Florida. In addition, the existing generating system is reviewed and includes planned unit retirements, expected modifications to operating performance, capital, fixed O&M, and variable O&M since the integration of new resources has the potential to impact the utilization of existing generating assets.

SYSTEM RELIABILITY PROCESS

Q. Please describe the criteria that Tampa Electric utilizes in its IRP process to determine both the minimum amount and timing of additional resources required to maintain system reliability.

A. Tampa Electric utilizes a 20 percent firm reserve margin reliability criteria above the system firm peak, as required by the Florida Public Service Commission ("Commission") in Order No. PSC-99-2507-S-EU issued on December 22, 1999, and a minimum 7 percent supply reserve margin. The firm reserve margin consists of both supply and non-firm demand resources to maintain an allowance for unexpected variances in system demand, generating unit availability, and purchased power availability and deliverability. The minimum supply reserve margin criterion maintains an important qualitative component of firm reserves for reliability purposes to minimize the impact of the loss of a supply resource at the time of peak.

If the firm reserve margin consisted of only non-firm demand reserves (whereby total firm supply equals total load), then the frequency of use of demand resources in a given year would increase significantly. The firm system peak is determined by including all firm wholesale agreements and excluding non-firm customer demand from the total system demand. Non-firm demand includes all interruptible service customers and customer load reduction programs. Customers who continue to participate in these voluntary programs help defer the need for additional supply resources by reducing firm peak demands. These customers may request to become a firm customer or be excluded from a DSM program with appropriate notification.

As reflected in its 2011 Ten Year Site Plan ("TYSP") and then updated in its 2012 TYSP analyses, Tampa Electric is expecting to incrementally reduce demand through 2017 by 70.4 MW and 33.1 MW in summer and winter, respectively, and reduce the system energy requirement by 230.7 GWH, but will still require 294 MW of capacity additions in 2017 to its existing supply resource mix to meet the 20 percent reserve margin criteria.

Q. Please describe the FRCC Minimum Reserve Margin Planning criterion.

A. The FRCC has established a minimum firm reserve margin planning criterion of 15 percent, taking into account the three investor owned utilities' requirement of twenty percent. The 15 percent margin is calculated using the aggregate planned firm peaks of all FRCC member utilities in addition to the aggregate generating units and firm PPAs; it also includes all net firm interchange via the bulk transmission ties to the SERC region. This margin assumes that all available capacity is deliverable to all load centers. During the FRCC presentation to the Commission at the TYSP workshop on August 13, 2012 ("TYSP workshop"), the FRCC presented analysis of the degree to which the peninsular Florida system is becoming increasingly dependent upon demand side management to meet its reserve margin criterion. In order to ensure the peninsular Florida system remains reliable in the future, the FRCC has developed and will monitor a metric for DSM as a percentage of regional peak.

SUPPLY RESOURCE ANALYSIS

Q. What supply alternatives were considered in the analysis that resulted in the selection of converting Polk 2-5 from simple cycle to CC as the company's next planned generating unit addition?

A. Tampa Electric considered a variety of options prior to identifying NGCC technology as the best option for Tampa Electric and its customers. Tampa Electric's screening process included natural gas, solid fuel and renewable technologies. General characteristics of natural gas technologies include lower emissions, lower heat rate, configured as either simple cycle or CC, wide range of capacity sizes, and competitive cost per unit output. Characteristics of solid fuel technologies include lower variable fuel costs and higher fixed costs, such as capital construction and fixed operating and maintenance costs, and somewhat higher emissions depending on environmental control technologies. Solid fuel technologies are typically better suited for large capacity and high utilization applications because these assets will dispatch for longer continuous periods of time. Their lower variable operating costs, longer ramp rates, and longer minimum down times make cycling off the units more difficult than natural gas based technology.

Renewable technologies tend to have lower or no fuel costs but have significant fixed costs. In addition, technologies such as geothermal and hydroelectric have limited practical application in Florida. Similarly, wind and solar have limited and unpredictable operating hours due to the intermittent nature of their energy source. In the absence of stored energy capability, intermittent renewables are best considered as energy resources and not as firm capacity for planning purposes. However, some renewable energy such as biomass can be considered as a firm resource if sufficient biomass material is stored and available.

Q. Which options were determined to be appropriate for Tampa Electric's needs and system characteristics and analyzed in greater detail?

A. The TYSP process included strategic considerations such as fuel price stability, fuel diversity, environmental impacts, technology viability, construction lead times, site availability, and FRCC regional supply needs in the 2012-2021 period. Tampa Electric's screening analysis narrowed the focus to natural gas-fired combined cycle or simple cycle technologies for further analysis in the IRP process.

Q. Please describe the natural gas-fired generation alternatives considered.

A. Tampa Electric considered in its screening simple cycle aero-derivative engines similar to Bayside Unit 3 and simple cycle combustion turbines similar to Polk Unit 5. The company also screened a stand-alone 2x1 combined cycle unit in addition to the integration of the existing Polk Units 2 through 5 peaking units into a combined cycle unit.

Q. Please describe the results of Tampa Electric's screening analysis used to select the best supply alternatives for the detailed economic analyses.

A. Tampa Electric's screening analysis of the various alternatives compared the levelized annual cost ($/kW-yr) of each technology at various capacity factors. The levelized cost includes the cost to construct, operate and maintain each technology. The slope of each cost curve is a function of the heat rate and variable O&M which increases linearly with the increasing capacity factor. For all technologies, the cost at zero capacity factor is simply the levelized construction cost and fixed O&M. Tampa Electric selected the following viable options: natural gas combined cycle technology as intermediate options and simple cycle combustion turbines as peaking options. The graphical results of the levelized cost screening curves are presented in Document No. 3 of my exhibit.

DEMAND RESOURCE ANALYSIS

Q. How were demand resources factored into the IRP process?

A. Tampa Electric included all DSM programs described by witness Bryant in its preliminary demand and energy forecast, which effectively reduced system peaks and energy requirements. By 2017, Tampa Electric's existing and incremental DSM programs are projected to contribute summer and winter demand reductions of 376.4 MW and 752.1 MW, respectively and energy conservation of 1,000.7 GWH is expected and is reflected in the projected firm peak and system energy requirements.

Q. Is it possible for Tampa Electric to meet its expected resource needs through additional DSM and renewable energy resources?

A. No. As previously stated, Tampa Electric identified all cost-effective DSM reductions and utilized that potential in the assessment of this determination of need. There are no additional cost-effective DSM alternatives (above the currently forecasted demand reductions and energy conservation) or viable cost-effective renewable energy resources that would defer the need for additional generating capacity in 2017.

RELIABILITY ANALYSIS AND RESOURCE PLAN

Q. Please describe the results of the reliability analysis.

A. The reliability analysis was based on existing generating unit operating data and projected system firm peak and energy requirements which were developed in summer 2011. This data supported the development of Tampa Electric's 2012 TYSP filed with the Commission in April 2012. This analysis indicated incremental supply resources are needed in 2017 to meet the 20 percent reserve margin criteria and 7 percent minimum supply criteria, as shown on Document No. 4 of my exhibit. Without additional firm supply resources the summer firm reserve margin is 12.5 percent and the supply component would fall to 6.8 percent in summer 2017.

Q. Please describe the results of the FRCC region reliability analysis.

A. Tampa Electric's 2012 TYSP data was included in the aggregate 2012 FRCC TYSP workshop presentation to the Commission on August 13, 2012. The FRCC reserve margin table in Document No. 5 of my exhibit shows that the existing planned demand and supply resource additions by Florida utilities will meet the minimum reliability of 15 percent through 2021. However, the initial reliability assessment should remove all planned and proposed unit additions and review potential modifications to existing generating capacity.

In addition, the FRCC has analyzed the increasing dependency on DSM programs to provide these reserves. Beginning with the 2012 Load & Resource Plan, the FRCC developed a metric for DSM as a percentage of regional peak. During the FRCC workshop, it was reported that of the eight NERC reliability regions, the FRCC is among the highest in DSM as a percentage of regional peak.

This increased dependency on DSM programs combined with the uncertainty of planned yet uncommitted supply additions as well as existing resources at risk of retirement due to emerging environmental regulations or other factors raise questions regarding future reserve margin calculations. If future additions do not materialize and some existing resources in the region are retired in response to costly mandatory retrofits, the FRCC reserve margin could drop below the minimum required from 2016 through 2019. This sensitivity analysis is reflected in Document No. 6 of my exhibit.

Q. Please describe the results of the preliminary IRP analysis.

A. The IRP included an additional 70.4 MW and 33.1 MW of summer and winter demand reductions and incremental energy conservation of 230.7 GWH compared to the cumulative reductions to date. The IRP also confirmed the need for firm purchases through 2016, and confirmed the need for the conversion of the existing Polk 2-5 peaking units to combined cycle in 2017 together with an additional simple cycle combustion turbine in 2019. The preliminary resource plan is shown in Document No. 7 of my exhibit. This shows that accelerating the Polk 2-5 in-service date from 2019 as shown in the 2011 TYSP to 2017 resulted in $65.4 million in savings.

The IRP screening process identified numerous resource plans and two alternate plans were selected for further comparative analysis to the Polk 2-5 plan. The first alternate plan utilized only simple-cycle peaking unit additions throughout the planning horizon, and the second alternate plan utilized simple-cycle peaking units in the near term with the conversion of the Polk CTs to a NGCC in 2025. The final IRP resource plans that Tampa Electric considered are shown in Document No. 8 of my exhibit.

Q. Please describe the results of the final IRP analysis.

A. Tampa Electric's economic evaluation process and consideration of qualitative factors determined that constructing NGCC technology at Polk Power Station represented the most cost-effective option for Tampa Electric and its customers. The expansion plan was then used to develop avoided cost parameters to evaluate new and modified DSM programs. The final Polk 2-5 plan demonstrated a CPWRR savings of $231.1 million when compared to the next best alternative. The two alternate plans are higher total cost utilizing the base assumptions due to higher operating costs. This base economic analysis is shown in Document No. 8 of my exhibit.

Q. Did Tampa Electric conduct sensitivity analyses related to the selection of Polk 2-5 in the IRP process?

A. Yes. Tampa Electric conducted sensitivity analyses to compare the Polk 2-5 plan with the two alternate expansion plans. The analyses tested the sensitivity of the recommended plan to independent variances in fuel prices, customer demand and energy forecasts, and expansion plan construction costs. High and low fuel forecast bands are discussed in the direct testimony of Tampa Electric witness J. Brent Caldwell. High and low customer demand forecast bands are discussed in the direct testimony of Tampa Electric witness Lorraine L. Cifuentes. High and low construction cost bands are discussed in the direct testimony of Tampa Electric witness Mark J. Hornick. The analysis held all other factors constant while applying the targeted sensitivities to the recommended plan and alternate plans to determine the total systems costs and compare the 30-year CPWRR.

Q. Please describe the results of the IRP sensitivity analyses.

A. After completion of the six sensitivity cases mentioned above, Polk 2-5 was found to be the most economical choice in all cases. When comparing Polk 2-5 to the two alternate plans in the capital cost sensitivities, Polk 2-5 showed savings of $217.7 million (low cost) and $229.3 million (high cost) in CPWRR compared to the next most cost-effective option. When comparing Polk 2-5 to the two alternate plans in the customer demand and energy sensitivities, Polk 2-5 showed savings of $283.9 million (low demand) and $75.6 million (high demand) in CPWRR compared to the next most cost-effective option. When comparing Polk 2-5 to the two alternate plans in the fuel price sensitivities, Polk 2-5 showed savings of $106.2 million (low fuel cost) and $304.0 million (high fuel cost) in CPWRR compared to the next most cost-effective option. A summary of the economic sensitivity analysis is shown in Document No. 9 of my exhibit.

RESOURCE REQUEST FOR PROPOSALS

Q. Did Tampa Electric conduct an RFP to solicit proposals to meet its peaking needs from 2013 through 2016 to replace the expiration of the 20-year Hardee Power agreement that expires on December 31, 2012?

A. Yes. In 2011, Tampa Electric issued a Request for Proposals ("RFP") to solicit market proposals for capacity needs from known participants in the market and conducted bilateral negotiations with the top proposals. This resulted in selecting two competitive agreements to purchase 117 MW peaking power through the end of 2016 and 160 MW peaking power through the end of 2015.

Q. Did Tampa Electric conduct an RFP to solicit alternatives to meet its need for intermediate power beginning in 2017?

A. Yes. Tampa Electric conducted an RFP which solicited proposals from all market participants. In March 2012, Tampa Electric issued an RFP soliciting firm offers for cost-effective alternatives to Polk 2-5. The RFP development and evaluation process are discussed here and in the direct testimony of witness Alan S. Taylor on behalf of Tampa Electric.

Q. Please describe the development process of the RFP.

A. Various subject matter experts from across the company, along with witness Taylor as the independent evaluator, crafted, reviewed and edited the RFP document. It incorporated sufficient schedule, scope and basis detail for all respondents in the preparation of their bid, specifying how their bid would be evaluated. As an attachment to the RFP, Tampa Electric included a draft PPA that provided respondents with a clear understanding of the general terms and conditions.

Q. Please describe the evaluation process of the RFP?

A. The evaluation process included: initial screening for minimum requirements, high level economic evaluation of individual proposals, present value economic screen of proposals, and a final evaluation of total system costs and non-economic factors. Short-listed bidders were invited to make a best and final offer. The final present value evaluation included a relative evaluation of non-economic factors.

In addition to evaluating individual proposals, Tampa Electric evaluated combinations of proposals into portfolios of generating alternatives in order to solicit a robust range of individual proposals. Eligible proposals that passed initial screening and individual economic ranking, but did not individually meet the capacity requirement for a given year, were evaluated in portfolios that matched them with other resources to meet the capacity need and the sequence of annual need identified in the solicitation.

Q. What was the result of the RFP for 2017 capacity?

A. Document No. 10 of my exhibit contains a summary of the short-listed bidders. After comparing the results of Tampa Electric's analysis and those performed by the independent evaluator, Polk 2-5 NGCC was selected as the most cost-effective alternative. This resulted in a CPWRR savings of $117.9 million relative to the next higher cost bidder. A summary of the RFP resource plans and economic analysis is shown in Document No. 11 of my exhibit.

Q. Please describe Tampa Electric's proposed Polk 2-5 NGCC unit.

A. The existing Polk 2 through 5 combustion turbines will be converted to a NGCC facility located at Polk Power Station by integrating a new steam turbine with an additional capacity of 459 MW summer and 463 MW winter, incrementally. This incremental capacity is derived from waste heat from the four existing combustion turbines of 339 MW summer and 352 MW winter, as well as 120 MW summer and 111 MW winter from supplemental natural gas duct-firing in the four HRSGs. This supplemental firing eliminates the need for two future aero-derivative peaking units due to the expiration of a 121 MW PPA on December 31, 2018. In addition, after the Polk 2-5 conversion to NGCC, the HRSGs are designed to allow the existing combustion turbines to operate independently in simple cycle mode in the event the steam turbine is unavailable, providing significant system reliability and operating flexibility. The NGCC configuration also enables the potential integration of solar thermal renewable capacity and energy in the future.

Q. Does Polk 2-5 have dual fuel capability?

A. The existing Polk Units 2 and 3 have dual fuel capability; the existing Polk Units 4 and 5 are currently natural gas fuel only, but will be permitted for future dual fuel capability. The cost for converting Units 4 and 5 are not included in the construction and operating plan.

Q. Please describe the consideration of the qualitative factors in the selection of Polk 2-5.

A. Tampa Electric considered 13 unique non-economic, qualitative factors in its selection. The proposals were evaluated individually and in the relative context of the other proposals. Document No. 12 of my exhibit contains a summary of the evaluation of the relative qualitative factors. Polk 2-5 NGCC was favored due to its overall reliability, system emissions rate, and dispatchability.

FINAL RECOMMENDED RESOURCE PLAN

Q. Were any resource plan assumptions updated prior to developing the final recommended resource plan and after the implementation of the RFP?

A. Yes. As part of the business planning cycle for Tampa Electric, the fuel forecast, the customer demand forecast, and other operating and financial forecasts are updated in June 2012 of each year. These updated forecasts are the basis for the next business planning cycle and activities, including: studies which support all of the cost recovery clause filings in August for reforecasting end of current year and following year projections. These updated assumptions are also used to develop the company's following year TYSP filed in April. As a result, Tampa Electric updated its fuel price and customer demand forecast in June 2012 as part of its normal business cycle and in preparation for the 2013 fuel adjustment filed in August 2012 and the

2013 TYSP filing due in April 2013. This analysis included the impacts of new and modified DSM programs. An assessment of the June 2012 updated fuel price forecast and customer demand and energy forecast confirm the forecasts are within the bands of the sensitivities used in the original IRP process. The updated fuel price forecast reflects lower natural gas prices overall; the updated solid fuel price forecast are somewhat lower as well.

The updated demand and energy forecast reflects lower growth in customer demand and energy requirements which reduces the amount of capacity needed in 2017 from 294 MW to 205 MW; this affirms Tampa Electric's stated need for additional resources in 2017. The updated forecasts were used to test the IRP and RFP recommended plan to construct Polk 2-5 NGCC as the most cost-effective alternative. For the IRP alternate expansion plan cases using updated forecasts, the Polk 2-5 plan resulted in CPWRR savings of $266.7 million relative to the closest IRP alternate expansion plan. For the RFP proposals using updated forecasts, the resulting CPWRR savings is $75.4 million relative to the most competitive bidder. Both of these updated forecast results support Tampa Electric's final recommended resource plan. Document No. 13 of my exhibit contains a summary of the analysis utilizing updated assumptions. Finally, considering the comprehensive analyses, the qualitative factors, and the benefit to state-wide reliability Polk 2-5 is the most cost effective alternative for customers.

Q. What is the expected relative average retail customer cost impact of Polk 2-5 compared to the reference case alternative?

A. The relative retail customer cost impact was calculated on an energy (MWH) basis. In 2017, the projected average retail customer cost impact for the Polk 2-5 NGCC plan is $6.09 per MWH; however, the customer cost recovery clause impact for Polk 2-5 NGCC is projected to be lower by $1.32 per MWH due to lower fuel and purchased power and capacity costs for a net customer cost impact of $4.76 per MWH compared to projected costs in 2016. The incremental supplemental duct-firing capacity of Polk 2-5 replaces the purchased power capacity that retires at end of 2018. This cost-effective incremental capacity eliminates the need for additional supply resources and the associated costs to construct and operate those avoided units. Finally, the PPA expiration incrementally lowers the customer cost recovery clause impact by an additional $0.50 per MWH that would otherwise occur in 2019.

BASIS FOR DETERMINATION OF NEED

Q. Has Tampa Electric adequately established that there is a need for Polk 2-5?

A. Yes. Tampa Electric will require an additional 294 MW of firm supply resources in 2017 based upon the reliability analysis. The most recent June 2012 forecast update for customer demand described in the testimony of witness Cifuentes reaffirms this need; based on this update, there is a need for 205 MW of firm supply resources in 2017.

Q. Is the addition of Polk 2-5 consistent with the needs of peninsular Florida?

A. Yes. Polk 2-5 does not significantly increase Tampa Electric's reliance on natural gas on an energy basis and is therefore consistent with state policy actions that encourage fuel diversity. The Polk 2-5 conversion significantly improves the efficiency of the four existing combustion turbines units and Tampa Electric's system overall by lowering the heat rate and dispatching ahead of other less efficient units. It should also be noted that load management and interruptible customer DSM programs are voluntary, so customers have a choice to withdraw from programs at any time with proper notification. During the

2012 TYSP Workshop on August 13, the FRCC presented a chart to the FPSC which showed the summer reserve margin without exercising load management or interruptibles would only be about 15 percent, which includes all planned additions, including Polk 2-5 in 2017.

Tampa Electric's need for additional natural gas-fired combined cycle capacity in January 2017 is consistent with the Peninsular Florida capacity needs in this same period, as identified by the FRCC and reported in the FRCC 2012 Regional Load and Resource Plan. The FRCC 2012 plan uses Tampa Electric specific data in conjunction with similar information from other Florida electric utilities. In addition, there are concerns regarding continued operation of existing solid fuel assets due to emerging environmental regulations and the costs to comply. Tampa Electric has completed all the required environmental controls for all of its solid fuel units. If future additions do not materialize and some existing resources in the region are retired in response to costly mandatory retrofits, the FRCC reserve margin could drop below the minimum required from 2016 through 2019.

ADVERSE CONSEQUENCES

Q. What would be the adverse consequences if the Polk 2-5 in-service date were delayed from 2017 to 2019?

A. In the event that Polk 2-5 is delayed by two years, project costs would increase, and customer fuel savings for 2017 and 2018 would not be realized. Tampa Electric would construct simple cycle peaking units in 2017 to cover the reserve margin requirement in 2017 and 2018. System energy requirements would be served by peaking capacity resulting in higher fuel costs. This would result in higher costs for customers of $65.4 million on a CPWRR basis. Witness Hornick describes the potential for an equipment demand spike scenario if there is a delay. If this equipment demand spike scenario materializes, this would result in higher costs for customers of $100.0 million on a CPWRR basis.

Q. What would be the adverse consequences if the proposed Polk 2-5 is denied?

A. If Polk 2-5 is denied, Tampa Electric would not be able to satisfy its minimum 20 percent Reserve Margin and minimum 7 percent supply planning criteria by the summer of 2017 in the most reliable and cost-effective manner. This would expose Tampa Electric's customers to a greater risk of interruption of service in the event of unanticipated forced outages or other contingencies for which Tampa Electric maintains reserves. Even without an interruption in service, without Polk 2-5 the company's customers would be subject to higher fuel costs as the company would have to rely on less efficient simple cycle generation to meet its need.

Q. Should Tampa Electric's petition for determination of need for Polk 2-5 be approved?

A. Yes. For the reasons I have described, Polk 2-5 is the most cost effective option for Tampa Electric's customers to maintain system reliability, environmental emission rates and fuel diversity. Tampa Electric requests that the Commission issue an affirmative determination of need for Polk 2-5 in this proceeding.

Q. Please summarize your direct testimony.

A. Tampa Electric's IRP process incorporated an on-going evaluation of demand and supply resources and conservation measures to maintain system reliability. By 2017, Tampa Electric's DSM programs will have produced summer and winter customer demand and energy reductions of 376.4 MW and 752.1 MW, respectively and energy conservation of 1,000.7 GWH. The reliability analysis determined that Tampa Electric will have capacity needs by 2017 of 294 MW. Alternate plans, technologies, sensitivities, timing, and a market solicitation were evaluated and the selection of Polk 2-5 was supported by subsequent economic analyses of viable supply alternatives, demonstrating that Polk 2-5 is the most cost-effective option compared to other technologies and available supply capacity from the Florida market.

After consideration of all existing, new and modified DSM programs and renewable energy initiatives, the construction of Polk 2-5 with a January 2017 in-service date should not be deferred. A two-year deferral of the recommended plan could increase costs to customers by $100.0 million. Tampa Electric also determined that fuel diversity is a key objective and the addition of natural gas combined cycle technology in 2017 still maintains a prudent balance in Tampa Electric's capacity and energy mix. When considering the viability of uncommitted resources, the risk of emerging environmental regulations, and the uncertainty of voluntary DSM programs, Polk 2-5 is needed as a firm resource within the FRCC region.

Polk 2-5 provides significant savings of $117.9 million to Tampa Electric's customers when compared to the most cost-effective alternative while providing additional benefits in the areas of reliability, fuel diversity, environmental impacts, and generating system efficiency. The results of these scenarios reinforce Tampa Electric's selection of Polk 2-5 as the best alternative for Tampa Electric and its customers.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BY MR. WAHLEN:

Q Okay. Thank you. Mr. Rocha, would you please summarize your direct testimony?

A I will. Good afternoon -- morning -- afternoon right on the button.

Tampa Electric is seeking a determination of need for the conversion of the existing Polk 2-5 units into a highly efficient combined cycle unit. Most of the capacity gained from this project is the installation of a steam turbine to capture approximately 340 megawatts of waste heat from the four existing combustion turbines that is currently being vented into the air. The generation from this waste heat recovery is enough to serve over 100,000 homes.

There will also be an additional 120 megawatts achieved from supplemental natural gas firing in the four heat recovery steam generators, or HRSGs. This is a process where natural gas is used to provide additional heat for even more steam generation during times of peak demand. This supplemental firing eliminates the need for two future peaking units.

In addition, the HRSGs will be designed to allow the existing combustion turbines to operate independently in simple cycle mode in the event the steam turbine is unavailable, providing significant system reliability and operating flexibility.

Finally, the natural gas combined cycle configuration enables the potential integration of renewable solar thermal energy in the future.

Tampa Electric's IRP process incorporated an ongoing evaluation of demand and supply resources and conservation measures to maintain system reliability. While the company has achieved significant load and energy savings through the implementation of various DSM and conservation programs, as well as incentives to use renewable resources, the reliability allows (phonetic) that Tampa Electric will still have a capacity need in 2017 of 205 megawatts with the latest updates.

Alternative technologies along with sensitivities related to fuel pricing, load growth, and capital costs were evaluated to ensure this project was Tampa Electric's most cost-effective option for its customers.

Next, the company issued a request for proposals where various offers for the needed capacities were received and evaluated against the Polk 2-5 project.

The economic analyses of these viable supply alternatives demonstrated that the Polk waste heat recovery project is the most cost-effective option compared to other technologies and available capacity from the market, while also dramatically reducing environmental emission rates, conserving fresh water through the use of reclaimed water, leveraging the existing site and infrastructure, and delivering many transmission benefits to reduce congestion and improve reliability.

Tampa Electric also acknowledged that fuel diversity is a key objective, and the addition of this natural gas combined cycle technology in 2017 still maintains a prudent balance in Tampa Electric's capacity and energy mix.

Also, when considering the viability of uncommitted resources and the risk of emerging environmental regulations, Polk 2-5 is needed as a firm resource within the FRCC region.

In conclusion, the Polk 2-5 project with its benefit of capturing waste heat from four existing combustion turbines provides significant savings to Tampa Electric's customers when compared to the most cost-effective alternative, while providing additional benefits in the areas of reliability, fuel diversity, environmental impacts, and generating system efficiency. The results of our evaluation and that of our independent evaluator reinforce Tampa Electric's selection of Polk 2-5 as the best alternative for Tampa Electric and our customers. Thank you, Commissioners.

MR. WAHLEN: Mr. Rocha is available for questions.

CHAIRMAN BRISÉ: Mr. Wright.

MR. WRIGHT: Thank you. Excuse me. Thank you, Mr. Chairman. Something jumped into my throat.

CROSS EXAMINATION

BY MR. WRIGHT:

Q Good morning, Mr. Rocha.

A Good morning.

Q It's good to see you again after all these years.

A Yes, sir. That's right.

Q Just for, to be clear on definitions, if I refer to the Polk project, to the Polk conversion project, we'll know we're talking about the company's proposed combined cycle project with duct burners; correct?

A We're on the same page.

Q All right. And if I refer to Tampa Electric's 2019 CT, that's a projected 7FA combustion turbine unit; correct?

A Yes.

Q And I think we've all agreed that the DeSoto facility is Proposal B as evaluated in your RFP process; correct?

A Very well. Thank you for that.

Q Thank you.

Did you personally review all of the proposals received in response to the RFP?

A The proposals, I did, after the initial proposals were opened by our independent evaluator first.

Q And so you did personally review DeSoto's proposal?

A I read all of the, I reviewed all of the proposals. Yes.

Q Did you ever speak with representatives of DeSoto Generating Company?

A The plan was that Benjamin Smith, who works for Mr. Brent Caldwell, would be the point of contact with all bidders. So I did not.

Q Okay. Thanks. In your work here you evaluated a number of alternate generation expansion plan options; correct?

A I did. Moving back to the IRP process before, of course, the RFP went out.

Q And is that the same process that the company goes through when it prepares its Ten-Year Site Plan?

A Yes, it is.

Q Thank you. And are you the responsible guy for, for that process in the Ten-Year Site Plan process as well?

A Yes. Yes, sir.

Q Thanks. And it was you and/or members, folks who work for or with you who prepared the economic analyses for the Polk project that are reflected in your testimony and in the need study?

A That is correct.

Q Thank you. And the analytical approach you use is a 30-year cumulative present worth revenue requirement minimization approach; correct?

A Yes.

Q I've got a couple of questions for you about your exhibits and the sensitivity analyses you did. If you could look at document 9 and document 8 of your, of your exhibit.

Let's look at document 8 first, please. These three -- this table shows three alternate resource plans; correct?

A Yes, it does.

Q And do I understand correctly that all of the units shown in each of these resource plans are Tampa Electric self-built units?

A All of the future plants are proposed at this time. I don't know who will build them because they may be subject to RFPs.

Q Okay.

A But these are the expansion plans and the current PPAs that Tampa Electric has to meet our reserve margin requirement that came out of the IRP.

Q Okay. And the real point I'm trying to get to is these, these plans are, are IRP plans. They do not include any of the proposals received in response to the RFP; correct?

A Oh, no. This was prior to that.

Q Thanks. And so in document 9, the IRP sensitivity analysis, again, these only address, these sensitivity analyses reported in your document 9 only address the three expansion plans shown in document 8; correct?

A Yes. In the development of the Ten-Year Site Plan we do many sensitivities to select the best technology and timing for customers.

Q When you got to the stage of evaluating proposals, DeSoto and A, C, and D, did you run the same or comparable sensitivities for the DeSoto purchase as those sensitivities reflected in your document number 9?

A We do -- we did perform sensitivities similar to those.

Q Just trying to understand --

A Well, to be specific --

Q Yeah, please.

A -- we did do customer demand and fuel sensitivities. I'm not -- you know, obviously capital costs, we wouldn't have done that for the proposals. Their proposal was a firm proposal.

Q Okay. So you would have done a low fuel cost sensitivity for the, for the RFP proposals?

A Yes.

Q Okay. Do you know whether you did an updated sensitivity, updated sensitivity analyses based on the June 2012 updated fuel costs?

A Yes. The staff asked that exact question, and it was question number 75.

Q Thank you. The cost-effectiveness of the Polk project is, is significantly dependent on future natural gas prices, is it not?

A That is -- it is dependent on fuel prices. Obviously demand and energy is a big, is a big one in IRP when we do these models, and then fuel prices are next. And then, of course, timing is very important.

MR. WRIGHT: Okay. I have an exhibit, Mr. Chairman.

CHAIRMAN BRISÉ: Sure. We are at 29.

(Exhibit 29 marked for identification.)

BY MR. WRIGHT:

Q Okay. This is -- there have been some different numbers presented in evidence in this -- or in discovery and testimony in this case relative to the savings as estimated by yourself really of Polk versus the DeSoto project. And if you could look at, first look at page 27 of your testimony.

A I'm there.

Q You testified there that the projected CPWRR savings of Polk versus the next most cost-effective alternative was 132.4 million; correct?

A Prior to the revision, yes, that is correct.

Q And that was -- in fact, that was -- DeSoto was the next most cost-effective alternative; correct?

A Yes. That is correct.

Q Okay. And then you did an update in June, and that changed the number from 132 to 97 million?

A Yes. As part -- every year, you know, there's always a time you put pencils down and get assumptions, and every year around June we get a new customer forecast of use and also a fuel forecast, and that serves as the basis for the next year, and that is what we used. We did update.

Q Okay. And then if you would look at the, the first page following the cover page of the little exhibit I just handed out. That's page 61 of the company's need study. And the table at the top there shows the, shows the CPWRRs based on the revised, the revised estimates from the June updates; correct?

A Yes. That is our latest update in June.

Q Okay. And then the next page is the staff asked you a question about the calculations shown in, I guess it was actually in, in that table, and you said that, in October you said that everything was okay, but then in November you identified another, another correction that needed to be made. And that reduced that 97 million to 75.4 million; correct?

A I, I would correct, correct you in that I think it was interrogatory 75 that led us to this, that correction.

Q Okay.

A And the question was the high and low fuel forecast on the, on the new updates. And just to get to the heart of the matter, when we did the high and low and you look at results and you see the trends, and does this make sense, there was something that stood out to me. My folks looked into the analysis and found that the, in the back end after the DeSoto project comes in service you always have to fill the next need and the next need and the next need.

In order to make the DeSoto project most cost-effective, the next need should be a combined cycle like the Polk 2 project; otherwise, it would be hundreds of millions of dollars less cost-effective. And so the supplemental firing portion was not modeled correctly, and it was something I should have caught. I always hope to be error free. And so my folks found that and reported it right away, and revised the number from 97 to $75 million net benefit to customers.

Q With the understanding that the numbers changed, I have some questions about where certain buckets of dollars show up in Table 13 and any successor tables. Table 13 is the one on page 61 of the need study.

A Yes.

Q The first question is where do transmission costs show up in, in this table?

A Transmission costs would show up under capital. Wheeling costs, which are also required for the DeSoto project, would be under fuel and purchased power.

Q Thank you. And similar question, would firm gas transportation costs show up in the fuel and purchased power row of that table?

A Yes, they would.

Q Thank you. Did you consider any alteratives to the assumption of firm FPL wheeling to get DeSoto power to Tampa Electric?

A I did not, and let me just use an example.

In 2010, we did purchase some energy from the DeSoto project, and we had two freezes, cold -- we call them freezes in Tampa -- that year, and some of the energy was curtailed because it was not able to be wheeled.

Q I think Mr. Caldwell testified earlier that he furnished the firm gas transportation costs to Mr. Taylor. Does that sound right to you?

A Yes, he did, both the cost and the volumes.

Q Okay. And did you use those same figures in, in your analyses?

A Absolutely.

Q Thank you. Okay.

MR. WRIGHT: Mr. Chairman, I have a confidential exhibit. With your indulgence, I would propose that we'll file a notice of intent to request confidential treatment for this and one other document by the end of the day, and the appropriate request for confidential classification within the next four, four business days.

CHAIRMAN BRISÉ: Okay. Mr. Beasley?

MR. BEASLEY: That's fine with us.

CHAIRMAN BRISÉ: Okay. This is number 30.

(Confidential Exhibit 30 marked for identification.)

BY MR. WRIGHT:

Q Mr. Rocha, this is a copy of the letter transmitting DeSoto Generating Company's best and final offer to Mr. Smith at Tampa Electric. Have you seen this before?

A I have.

Q Thank you. And I know, I know you're familiar with the drill here, but we have to do this, this fun little conversational dance of I ask you questions that are designed to talk about what's there, but we're not supposed to talk about the actual substantive content of what's there. Okay?

A Yes, sir.

Q Thanks. And this was, as far as you know, this was received on the date sent, July 13th, 2012?

A To the best of my knowledge.

Q Okay. What, if any, communications did you have with DeSoto between July 13th and July 27th, 2012?

A I had no conversations ever with DeSoto. That all went through Mr. Benjamin Smith.

Q Okay. Thank you. In the analyses of the DeSoto cost-effectiveness, did you assume that the purchase would be closed on June 1st, 2013?

A Yes.

Q Thank you. Now we get to do our little proverbial --

A Hence the line numbers you have?

Q Hence the line numbers so that we can talk about exactly what's what.

The -- if you would, please, look at the highlighted content -- well, I show all the content on lines 10 through 12. I just want to ask you -- you said you're familiar with the document.

A Yes.

Q Question, would the proposal that is offered there by DeSoto have enabled Tampa Electric Company to avoid any risk associated with incremental transmission costs during the period 2013 through 2016?

A I'm not the subject matter expert on transmission, but I don't see how it would impact that need. This is just -- I don't know how to describe it -- a PPA. Can I say that?

Q Did you understand the content of what's there as reflecting DeSoto's willingness to take the risk for transmission costs that might be associated with the operation of the facility during that period?

A No, I didn't look at that that way at all. I looked at this as a means of addressing the reserve margin need of a unit coming in four years prior to the in-service date and yet still not being the most cost-effective option for customers.

Q And I think I know what the answer is going to be based on that answer, but I do want to ask you the same question --

A Yes, sir.

Q -- with respect to firm gas transportation costs. Did you not understand that this would remove any risk associated with firm gas transportation costs from Tampa Electric Company?

A I did not understand it that way because I would not agree with that. Purchasing this asset that would require -- would show revenue requirements to customers beginning in 2013 would require a firm energy for both transmission and gas transportation.

MR. WRIGHT: Mr. Chairman, I have another confidential exhibit, and this, this is the executive summary of the DeSoto proposal that was furnished to -- presented to Tampa Electric Company.

CHAIRMAN BRISÉ: Okay. That would be Number

31.

(Confidential Exhibit 31 marked for identification.)

BY MR. WRIGHT:

Q Before we go on to -- I'm sorry. It is completely --

A Now we're directly in the confidential.

Q It is completely fair for you to take your time and look at the exhibits and I didn't want to interrupt you.

A Very good.

Q Okay. But before we go on to I guess what has now been marked as --

CHAIRMAN BRISÉ: 31.

MR. WRIGHT: Thank you.

BY MR. WRIGHT:

Q What has now been marked as Exhibit 30, the best and final offer, I just want to ask you -- the previous one I gave you. Okay. This is, this is a process question. It's not a content question.

A Okay.

Q Do you know whether anyone from Tampa Electric -- well, back up. Predicate. I asked you whether you understood the content there to mean such and such. You said you did not.

Do you know whether anyone from Tampa Electric Company spoke with DeSoto representatives in an effort to clarify the meaning and the intent of the content that we're dancing around here?

A I do not know.

Q Okay. Thank you.

A Benjamin Smith would have been and -- under Brent Caldwell's guidance.

Q Thank you. Okay. The good news with respect to what has now been marked as Number 31, which is the executive summary of the DeSoto proposal, is that there's only a little bit of information there that's highlighted, and so the rest of it is, is nonconfidential and will be published public accordingly when we file, you know, the redacted version. Everything else other than that little bit of highlighting there will be public. And the further good news is I just want to ask you about the nonconfidential information there.

A Okay.

Q Okay. You'd agree that both the initial purchase sale price and the best and final offer sale price are a lot less than $706 million; correct?

A I would agree that the initial capital costs are a lot less, and there's always the total costs that must be considered for customers.

Q Absolutely. That's your job.

A That's -- yes, sir.

Q And you'd agree that DeSoto, you said you bought from DeSoto and it does have a proven operating history in Florida?

A They are an experienced operator of power plants.

Q And you acknowledged that DeSoto does have dual fuel capability?

A Yes, they do.

Q Are you aware that Tampa Electric is at least sometimes currently involved in attempting to market capacity?

A There's a -- we deal every day in between the marketing function and the reliability function. So sometimes I don't know, always know everything that's going on, where it's shared. But I still don't know -- I'm sure they try.

Q You'll note that the last open circle bullet toward the -- there's a bunch of, there's seven open circle bullets in the middle of the page there, and the last one references DeSoto's representation that DeSoto could be converted to combined cycle at a later date. Do you see that?

A Yes, I do.

Q Okay. Did you, did you evaluate that claim by DeSoto?

A What we -- not, not exactly that. What we did was, in the expansion plan after the peakers, looked and determined that the next viable alternative was a combined cycle. And the only one I had numbers on to evaluate as a combined cycle would have been the Polk 2 project.

Q Okay. And that's a 4-on-1; correct?

A It is.

Q Okay. So you didn't evaluate any 2-on-1 options?

A During the IRP we certainly did.

Q Okay.

A But not at this stage once we were evaluating head-to-head proposals that we were provided.

Q If you assume that DeSoto was available to Tampa Electric as of June 2013, did you assign or give any credit or assume any value for additional reliability that the additional capacity would provide between 2013 and 2017?

A No, for two reasons. We're already here in December, and the amount of transmission interconnection that's required -- I think it's been announced, that's not a private number, 17 million -- that hasn't commenced. It would have to be done by June. And to provide the total output as firm, you could, of course, receive it as, as, as non-firm, so.

Q Did you consider any value that, that having the DeSoto plant online would have in terms of avoiding the 160-megawatt unspecified capacity purchase in 2016?

A Absolutely did. And, in fact, that's a significant benefit that shows in the DeSoto proposal. In the Tampa Electric self-build case we renewed, we used numbers from an option, and that hit our economic analysis by $15 million.

In the case, since we would be purchasing in June of 2013, we removed that from the analysis such that there was a $15 million benefit in 2016 for the DeSoto project.

Q Did you consider any -- did you assign any value to potential capacity revenues that might be made available from DeSoto?

A I did not, and I do not do that on any proposal in any prospective speculative sales.

Q Okay. And so if I asked you the same question about potential energy sales, the answer would be the same?

A That is correct.

Q Did you consider any possible value that Tampa Electric might realize if it were to defer the Polk project to keep an eye on gas prices or future technological developments?

A In terms -- help me with the question. Did I consider that in terms of?

Q If you defer, if you defer -- we do agree that $706 million is a lot of money; right?

A Any, any impact to customers is a lot of money. Yes.

Q Okay. If you were to postpone the addition of Polk -- and I understand, I understand your plan and I understand your analyses. But if you were to postpone the addition of Polk, that would give you a year, two years, whatever, to get a better handle on what gas prices are doing; correct?

A I -- you know, you also, in addition to the economics, you also need to consider reliability. And I think we've demonstrated and everyone has agreed that the need exists in 2017 for Polk 2.

Q Sure.

A And there is a need in '19 if we went with the DeSoto project.

Q And, but if you add DeSoto, you don't need Polk in '17. Your optimized -- do I understand your optimized plan would push Polk to '18; is that right?

A Not with the updated assumptions. It's '19 --

Q Oh, okay. Thanks.

A -- with the updated latest numbers.

Q In Table 11 of the need study -- it's on page 49.

A Thanks for the help.

Q In the Proposal B column, do I -- just trying to understand your last answer, that analysis presented, you know, back in your filing in September, showed Polk in '18. You just told us that Polk would move to '19; correct?

A With the new demand in energy forecast, it would move that one more year.

Q Thanks. And would the 2019 and 2022 CTs still drop out of the plan?

A They would -- I think one of them is deferred and one is not. But that's subject to check, one year.

Q Did the demand increase a lot in the update?

A No. The demand went down.

Q Okay.

A And so did fuel prices in the update.

Q Okay.

A In what we are calling June 2012 update.

Q So when you say one of the CTs was not deferred -- I was trying to ask about the 2019 and 2022 CTs, which are not shown anymore in the Proposal B column in that table.

A They are still needed. The 20 -- I see a 2029 and a 2026. I think the 2026 went to 2027 and the 2029 stayed in place.

Q Thank you very -- that answered the question I was trying to ask you. I appreciate it. Thanks.

I will bet you're familiar with the basic concept of benefit cost analysis. Is that a good bet?

A Yes.

Q In this context would it be fair to say that the company is proposing to spend $706 million to achieve something like $782 million of net present value benefits?

A Where is -- help me with the 782.

Q 706.6 plus 75.4, which is the CPWRR savings, is 782 million.

A The 75 is what accrues to the customer if they -- it's a delta between the two.

Q Right.

A I'm struggling with the way you've characterized it, that's all. But I think we would agree that it's 75 million benefit more to customers by selecting Polk 2.

Q Yeah. I understand, I understand that's, that's your position. So you're spending 706 to get 75 incremental. But, of course, you --

A Oh, there's a lot more fuel --

Q To get the benefit, you've got to get, you've got to get the whole 706 back too; right?

A There's a lot of fuel savings to customers. On the high fuel case, it's probably 25 million; those two years that you don't see the combined cycle on the system.

Q I've got just a couple more questions for you, you'll be happy to know. And it has to do with, these questions have to do with your results as, as compared to Mr. Taylor's results.

Your analyses showed, you know, 132 million savings adjusted to 97, adjusted to 75. All right. If I look at Mr. Taylor's exhibit -- I want to say it's Table A6 in his independent evaluation report. I think that's the one.

A Three-ring, it's slow moving the three-ring binder.

Q Yeah. Tell me about it.

Yeah. It is Table A6.

A I'm there.

Q Mr. Taylor's value shown for Proposal B DeSoto base case is a, is a net present value in 2012 dollars of $592 million to the bad. That's what that shows; correct?

A That's what it shows.

Q Okay. How, how -- if you know, how could your analyses come up with the $75 million net cost and Mr. Taylor's come up with a $592 million net additional cost?

A I'm not a subject matter expert on the Response Surface Model, and Mr. Taylor should be up next.

Tampa Electric's models are a whole system look of everything that happens over 30 years, all the fuel, all the expansion plans; and whereas Mr. Taylor's, my understanding, analysis is a head-to-head of this proposal versus that proposal. And I would defer to him on any more detailed questions on -- and that's why he's an independent evaluator, to have his own models and confirm that the best choice for customers is Polk 2 project.

Q You've been doing this a pretty long time, haven't you?

A No. This is my, this is my first time.

Q I meant generation expansion planning.

A Yeah. I've been in and out of generation expansion planning and have always worked with them. Because if you're going to do financial analysis and prove projects to the, to the senior executives, you have to ask for a lot of analysis. And then you ask a lot of questions: Why is it this, why is it that? So I would say yes.

Q Okay. And in your response just, just now, 45 seconds ago, you said the way you look at it, you look at the whole plan with all the units and all the moving parts and then you bring that back on a 30-year CPWRR basis; correct?

A Yes. That is what all the IOUs that I know of model in generation planning.

Q That answered my next and last question. Thank you, Mr. Rocha.

A Oh, thank you.

CHAIRMAN BRISÉ: Ms. Christensen?

MS. CHRISTENSEN: Yes, I have one clarifying question.

CROSS EXAMINATION

BY MS. CHRISTENSEN:

Q Mr. Rocha, you had testified a little bit earlier about there were some additional savings. You had said something about 25 million due to putting off CTs. Could you explain that a little bit in a little bit more detail, because I'm not sure I was understanding?

A I'm just -- help me with the 25. I don't remember.

Q Well, it may not be 25. You said there were some additional savings beyond the 75 million.

A Okay. We, we have never, and Mr. Wright was alluding to it, we've never looked at other benefits like transmission benefits may accrue to the system, and efficiency and congestion and being able to run more efficient units. And those times when dual fuel may be needed, we would have more dual fuel capability added to the state. And they're just hard to quantify those numbers, so.

Q Thank you.

A All right.

CHAIRMAN BRISÉ: Staff?

MS. BROWN: Staff has a few questions, sir.

CHAIRMAN BRISÉ: Sure. Go right ahead.

CROSS EXAMINATION

BY MS. BROWN:

Q Mr. Rocha, is it your testimony that Polk 2-5 is the most cost-effective alternative to reliably meet TECO's customers' needs?

A Yes, it is.

Q Could you please turn with us to document number 13 of your Exhibit RJR-1?

A Yes.

Q Based on the table at the bottom of that page, is it accurate to say that your analysis indicates that the resource plan for Polk 2-5 going into service in 2017 is approximately $75 million more cost-effective than the resource plan proposal would be?

A Yes.

Q And that $75 million value, is that accumulated value?

A It's -- yes, it is.

Q Okay. At this time staff will be distributing portions of staff's Exhibit Number 3, which was already admitted into evidence, and it's TECO's response to staff's interrog number 47. And we'll be referencing pages 2 and pages 4, which is Bates stamp number 67 and number 69.

Mr. Rocha, do you support TECO's response to staff's interrog number 47?

A Yes.

Q And if you compare the highlighted columns, cumulative columns, which is the last two sections on page 67 and 68, would you agree that the difference is the same as the value contained in your previously discussed Exhibit RJR-1, document number 13? I'm sorry. It's page 67 and 69. I'm sorry.

A Yes.

Q It is the same?

A Yes.

Q Okay. And a minute ago you also testified that your analysis shows that Polk 2-5 is more cost-effective than Proposal B. If you were to calculate accumulated value on a year-by-year basis, would you agree, subject to check, that Polk 2-5 would be more cost-effective in every year when compared to the resource plan with Proposal B?

A Those exhibits would show that, I know for a fact, through 2017 that it is more cost-effective.

Q Okay.

A Each and every year as far as revenue requirements.

MS. BROWN: Thank you, sir. No further questions.

CHAIRMAN BRISÉ: Commissioners? All right. Redirect.

MR. WAHLEN: Just a few redirect.

REDIRECT EXAMINATION

BY MR. WAHLEN:

Q Mr. Wright asked you some questions about the fuel forecast, and I wonder if you could compare the fuel efficiency of Proposal B with the Polk expansion proposal.

A Sure. The, the heat rate is always a funny thing because it's upside, it's kind of upside down to folks on the generation side; it's for fuel buyers.

Essentially our project is about a 50% efficiency, and a simple cycle 7F is less than 30% efficient in converting heat from the fuel to electricity.

Q Okay. Did I understand correctly that you think that the Polk expansion is 30% more fuel efficient than Proposal B?

A Yes.

Q How does that work when the fuel forecast and prices go up? When you're doing your comparisons and your sensitivities, if the fuel price goes up, does that make the Polk plant more or less favorable as compared to Proposal B?

A When fuel prices go up, efficiency matters. Right? You want a very efficient car when fuel prices are high. And so in the event that one would agree that our fuel forecast now is conservative and that has more potential to go up than down, then there is more potential benefit to customers if prices go up.

Q Now Mr. Wright asked you a number of questions about the proposed sale price of the DeSoto plant. He asked you to characterize it relative to the capital cost of the Polk expansion. Do you remember those questions?

A Yes.

Q Could you talk a little bit about the life cycle costs of the power plants and how significant capital costs are in the total analysis?

A In our business, fuel is a big number when you -- around a power plant. And just about every time I've looked at just the initial capital dollars compared to the total life cycle of variable O&M, FOM, and the big number, fuel, it's less than 20%, sometimes 14%.

So if you just narrow in on that initial capital cost, you're missing the whole big picture of what that unit would do on our system.

Q Okay. Thank you. Mr. Wright asked you some questions about conversations that might have occurred between July 13th and July 27th, and July 13th was the day the best and final offer was provided. I think you said you had no conversations. Am I remembering correctly?

A Yes.

Q Do you know whether there were any conversations with anybody at TECO in DeSoto during that time period?

A I, I do not know that. But July 13th in the RFP was best and final offer. So I'm trying to understand, you know, what would, conversation would happen next after they gave us our best and final.

All bidders were put on the same basis, they made their best and final, and we had two weeks to evaluate them.

Q Okay. Thank you. And in a best and final offer, would you expect there to be enough detail for you to understand all of the key points in the best and final offer?

A In this best and final offer that we saw, the numbers that were available were sufficient to model what they propose.

Q Okay. Thank you.

Now let me ask you one final question. Mr. Wright talked about potentially delaying this plant so we could see what happens with the fuel forecast and things like that.

Are there any disadvantages or problems that would occur if you delayed the purchase or the construction of the Polk plant?

A Well, yes. And the biggest one is

reliability. This plant is needed. It provides fuel savings. I mentioned 30, 30%. 75% of the project comes, of the output comes from waste heat, reusing that. It lowers our environmental emissions rates. And every sensitivity we ran showed that Polk 2 was the most cost-effective to customers. And so when you put all that together, 2017 is the right time to put this project in place to start accruing benefits to customers.

Q If you delayed it beyond 2017, would that eliminate potential fuel savings for customers?

A Yes.

Q Would it subject the company to the risk of construction cost increases?

A Yes. I think Mr. Hornick described that possibility.

Q And one last question. Mr. Rocha, just in general terms, do you think it makes sense to buy a power plant in '13 to meet a need in '17?

A In this case I would say no, because, again, it is not the most cost-effective option. And customers would face, if -- presuming full cost recovery, costs for those four years prior to the reserve margin need.

MR. WAHLEN: Thank you. Those are my questions. And we would move Exhibits 17 and 20 into the record.

CHAIRMAN BRISÉ: All right. At this time we'll move Exhibits 17 and 20 into the record.

(Exhibits 17 and 20 admitted into the record.)

Mr. Wright?

MR. WRIGHT: I move 19 -- sorry -- 29, 30, and 31, Mr. Chairman.

CHAIRMAN BRISÉ: All right. At this time we will move 29, 30, and 31 into the record.

(Exhibits 29, 30, and 31 admitted into the record.)

All right. Thank you, Mr. Rocha.

THE WITNESS: Yes, Mr. Chairman.

CHAIRMAN BRISÉ: Please call your next witness.

MR. BEASLEY: We call Alan S. Taylor.

Whereupon,

ALAN S. TAYLOR

was called as a witness on behalf of Tampa Electric Company and, having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. BEASLEY:

Q Mr. Taylor, you were sworn earlier today in this proceeding; correct?

A Yes, I was.

Q Would you please state your name and business address?

A My name is Alan Taylor. My business address is 821 15th Street, Boulder, Colorado 80302.

Q Mr. Taylor, by whom are you employed and what position do you hold?

A I'm employed by Sedway Consulting, Incorporated, and I'm the President of the company.

Q Thank you. Did you prepare and submit in this proceeding prepared direct testimony of Alan S. Taylor filed on September 12th, 2012?

A Yes, I did.

Q Do you have any revisions to your testimony?

A No, I do not.

Q If I were to ask you the questions contained in that testimony, would your answers be the same?

A Yes, they would.

MR. BEASLEY: I would ask that Mr. Taylor's testimony be inserted into the record as though read.

CHAIRMAN BRISÉ: At this time we will insert Mr. Taylor's prefiled testimony into the record as though read.

MR. BEASLEY: Thank you.

BY MR. BEASLEY:

Q Did you also prepare the exhibit that accompanied your testimony, which is identified as AST-1 and marked as hearing Exhibit 18?

A Yes, I did.

MR. BEASLEY: I would ask that Mr. Taylor's exhibit be recognized as Exhibit 18.

CHAIRMAN BRISÉ: Sure. We will mark Mr. Taylor's exhibit as Exhibit 18.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

ALAN S. TAYLOR

ON BEHALF OF TAMPA ELECTRIC COMPANY

Q. Please state your name and business address.

A. My name is Alan S. Taylor, and my business address is 821 15th Street, Boulder, Colorado, 80302.

Q. By whom are you employed and what position do you hold?

A. I am President of Sedway Consulting, Inc. ("Sedway Consulting").

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

A. I perform consulting engagements in which I assist utilities, regulators, and customers with the challenges that they may face in today's dynamic electricity marketplace. My area of specialization is in the provision of independent evaluation services in power supply solicitations and in the associated economic and financial analysis of power supply options.

Q. Please describe your education and professional experience.

A. I earned a Bachelor of Science Degree in energy engineering from the Massachusetts Institute of Technology and a Masters of Business Administration from the Haas School of Business at the University of California, Berkeley, where I specialized in finance and graduated valedictorian.

I have worked in the utility planning and operations area for 25 years, predominantly as a consultant specializing in integrated resource planning, competitive bidding analysis, utility industry restructuring, market price forecasting, and asset valuation. I have testified before state commissions in proceedings involving resource solicitations, environmental surcharges, and fuel adjustment clauses.

I began my career at Baltimore Gas & Electric Company (BG&E), where I performed efficiency and environmental compliance testing on the utility system's power plants. I subsequently worked for five years as a senior consultant at Energy Management Associates ("EMA", now New Energy Associates), training and assisting over two dozen utilities in their use of EMA's operational and strategic planning models, PROMOD III and PROSCREEN II. During my graduate studies, I was employed by Pacific Gas & Electric Company ("PG&E"), where I analyzed the utility's proposed demand side management ("DSM") incentive ratemaking mechanism, and by Lawrence Berkeley Laboratory ("LBL"), where I evaluated utility regulatory policies surrounding the development of brownfield generation sites.

Subsequently, I worked at PHB Hagler Bailly (and its predecessor firms) for ten years, serving as a vice president in the firm's Global Economic Business Services practice and as a senior member of the Wholesale Energy Markets practice of PA Consulting Group, when that firm acquired PHB Hagler Bailly in 2000. In 2001, I founded Sedway Consulting, Inc. and have continued to specialize in economic analyses associated with electricity wholesale markets. Since the founding of Sedway Consulting, I have provided independent evaluation services in over two dozen electric utility conventional and renewable resource solicitations.

Q. What is the purpose of your direct testimony?

A. Sedway Consulting was retained by Tampa Electric Company (Tampa Electric) to provide independent evaluation services in the utility's 2012 solicitation for competitive power supplies. As the principal consultant on the project, I helped with the development of the Request for Proposals ("RFP"), reviewed Tampa Electric's solicitation process, and performed a parallel and independent economic evaluation of both Tampa Electric's Next Planned Generating Unit ("NPGU") and the proposals that were received by Tampa Electric in response to the utility's solicitation. Ultimately, I concluded that Tampa Electric's Repowering of Polk 2-5 into a combined-cycle ("CC") facility described in Tampa Electric's RFP, with an in-service date of January, 2017, represented the most cost-effective resource for meeting Tampa Electric's resource needs for 2017.

The purpose of my direct testimony is to describe my role as an independent evaluator and present my findings. I will discuss the process and tools that I used to conduct Sedway Consulting's independent economic evaluation. Based on the results of my independent evaluation, I concluded that Tampa Electric's Polk Power Station

Repowering option is more cost-effective than the proposed power purchase agreement ("PPA") and asset sale alternatives that were submitted in Tampa Electric's resource solicitation.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring Exhibit No. AST-1 consisting of two documents, which are attached to my direct testimony:

Document No. 1 Resume of Alan S. Taylor

Document No. 2 Sedway Consulting's Independent Evaluation Report

Q. Please describe the role you performed as an independent evaluator in Tampa Electric's 2012 RFP project.

A. As the independent evaluator in Tampa Electric's 2012 power supply solicitation, I reviewed Tampa Electric's 2012 Ten-Year Site Plan and the utility's modeling processes pertaining to its use of Planning and Risk, Tampa Electric's detailed production costing model. I participated in the March 21, 2012 Pre-Issuance Conference Call and attended the April 4, 2012 Bidders Conference in Tampa. Before receiving the proposals, I requested that Tampa Electric run its Planning and Risk model and provide production costing results that I could use to calibrate Sedway Consulting's resource evaluation model. I participated in the opening of proposal packages in Tampa on the Proposal Due Date (May 22, 2012), retained an electronic copy of each submitted proposal, and evaluated the economic/pricing information from each proposal. Tampa Electric conferred with me on a number of issues relating to proposal RFP-noncompliance decisions, interpretation of proposal information, clarification requests, and economic evaluation assumptions. As the evaluation progressed, Tampa Electric and I discussed appropriate courses of action and modeling assumptions. Using Sedway Consulting's Response Surface Model ("RSM"), I evaluated Tampa Electric's NPGU and each submitted proposal and assessed their overall costs. I compared Sedway Consulting's ranking and results with those of Tampa Electric to confirm consistency of assumptions and concurrence of conclusions, and I documented the entire process in an independent evaluation report.

Q. You stated that you were involved in the development of the RFP. What did your involvement entail?

A. As the independent evaluator, I reviewed draft versions of the RFP document, participated in several discussions by phone, and was given the opportunity to provide my input and suggestions for improving the RFP.

Q. Do you believe that Tampa Electric's RFP was a reasonable document for soliciting proposals?

A. Yes. As one who has developed over a dozen such utility resource RFPs, I believe that Tampa Electric's RFP struck a good balance between being sufficiently detailed without being burdensome on the respondent. With its RFP, Tampa Electric released a draft PPA that provided bidders with a clear understanding of the general business arrangement that Tampa Electric contemplated.

Q. Do you believe that Tampa Electric's evaluation process was conducted fairly?

A. Yes. The proposals and Tampa Electric's NPGU were evaluated on an equal footing, with consistent assumptions applied to all resource options.

Q. Please describe Sedway Consulting's RSM model and its use in Tampa Electric's resource solicitation.

A. The RSM is a spreadsheet model that I have used in dozens of solicitations around the country. It is a relatively straightforward tool that allows one to independently assess the cost impacts of different generating or purchase resources for a utility's supply portfolio. Most of the evaluation analytics in the RSM involve calculations that are based entirely on my input of proposal costs and characteristics. A small part of the model examines system production cost impacts and needs to be calibrated to simulate a specific utility's system. In the case of the Tampa Electric solicitation, in the weeks prior to the proposal opening, I requested that Tampa Electric execute specific sets of runs with its detailed production cost model. With the results of these runs, I was able to calibrate the RSM to approximate the production cost results Tampa Electric's Planning and Risk model would produce in a subsequent evaluation of any proposals or self-build options that Tampa Electric might receive. Thus, I would not have to rely on Tampa Electric's modeling of a proposal or self-build option; instead, I would be able to insert my own inputs into my own model and independently evaluate the economic impact of any particular resource. In short, the RSM provides an independent assessment to help ensure against the inadvertent introduction of significant mistakes that could cause the evaluation team to reach the wrong conclusions.

Q. How is the RSM an independent analytical tool if it is based on initial Planning and Risk results?

A. As I noted above, most of the calculations performed by the RSM are not based on Planning and Risk results in any way. There are two main categories of costs that are evaluated in a resource solicitation: fixed costs and variable costs. The costs in the first category - the fixed costs of a proposal - are calculated entirely separately in the RSM, with no reliance on the Planning and Risk model for these calculations. The second category - variable costs - has two parts: (1) the calculation of a resource's variable dispatch rates and, (2) the impact that a resource with such variable rates is likely to have on Tampa Electric's total system production costs. As with the fixed costs, a proposal's variable dispatch rates are calculated entirely separately in the RSM, with no basis or reliance on the Planning and Risk model. It is only in the final subcategory - the impact that a resource is likely to have on system production costs - that the RSM has any reliance on calibrated results from Planning and Risk.

Q. Please elaborate on that area of calculations where the RSM is affected by the Planning and Risk calibration runs.

A. This is the area of system production costs. These costs represent the total fuel, variable operation and maintenance (O&M), emission, and purchased power energy costs that Tampa Electric incurs in serving its customers' load. Given Tampa Electric's load forecast, the existing Tampa Electric supply portfolio (i.e., all current generating facilities and purchase power contracts), and many specific assumptions about future resources and fuel costs, Planning and Risk simulates the dispatch of Tampa Electric's system and forecasts total production costs for each month of each year of the study period. At the outset of the solicitation project, the RSM was populated with monthly system production cost results that were created by the Planning and Risk calibration runs.

Q. What did the RSM do with this production cost information?

A. Once incorporated into the RSM, the production cost information allowed the RSM to answer the question: How much money (in monthly total production costs) is Tampa Electric likely to save if it acquires a proposed resource, relative to a reference resource? The use of a reference resource simply allowed a consistent point of comparison for evaluating all proposals and Tampa Electric's self-build options. As a reference resource, I used a hypothetical gas-fired resource with a very high variable dispatch rate associated with a heat rate of 25,000 Btu/kWh. In fact, I could have picked any variable dispatch or heat rate for the reference resource and obtained the same relative ranking of proposals out of the RSM. The cost of the reference resource has no impact on the relative results - it is merely a consistent reference point.

Q. Can you provide a numerical example that shows how the RSM works?

A. Certainly. Assume that a utility has a one-year resource need of 500 MW and must select one of the two following proposals:

	Proposal A	**Proposal B**
Capacity:	500 MW	500 MW
Capacity Price:	$9.00/kW-month	$5.50/kW-month
Energy Price:	$40/MWh	$60/MWh

For both proposals, the RSM has already calculated the fixed costs (and represented them in the capacity price) and the variable costs (and represented them in the energy price). Proposal A is more expensive in terms of fixed costs, but Proposal B is more expensive on an energy cost basis. The RSM calculates the final piece of the economic analysis - the different impacts on system production costs - to determine which proposal is less expensive in a total sense for the utility system as a whole.

Assume that the 25,000 Btu/kWh reference unit has a variable cost of $150/MWh and that the RSM has been calibrated and populated with the following production cost information:

For a 500 MW proxy resource, the utility's one-year total system production costs are:

$900 million for a $150/MWh energy price reference resource

$894 million for a $60/MWh energy price resource (Proposal B)

$876 million for a $40/MWh energy price resource (Proposal A)

Thus, the energy savings (relative to the selection of a $150/MWh reference resource) are $24 million for Proposal A with its $40/MWh energy price and $6 million for Proposal B with its $60/MWh energy price. In its proposal ranking process, the RSM converts all production cost savings into a $/kW-month equivalent value so that the savings can be deducted from the capacity price to yield a final net cost (in $/kW-month) for each proposal. Converting the energy savings in this numerical example into $/kW-month equivalent values yields the following:

$24 million / (500 MW * 12 months) = $4.00/kW-month
$6 million / (500 MW * 12 months) = $1.00/kW-month

The RSM calculates the net cost of both proposals by subtracting the energy cost savings from the fixed costs:

	Proposal A	**Proposal B**
Capacity Price:	$9.00/kW-month	$5.50/kW-month
Energy Cost Savings:	$4.00/kW-month	$1.00/kW-month
Net Cost:	$5.00/kW-month	$4.50/kW-month

Proposal B is less expensive. This can be confirmed through a total cost analysis as well:

Proposal A will require total capacity payments of $54 million (= 500 MW x $9.00/kW-month x 12 months), and Proposal B will require $33 million (= 500 MW x $5.50/kW-month x 12 months). Thus, Proposal A has fixed costs that are $21 million more than Proposal B.

Proposal A will provide $18 million more in energy cost savings (= $24 million - $6 million); however, this is not enough to warrant paying $21 million more in fixed costs. Therefore, Proposal B is the less expensive alternative.

Note that the RSM is described in more detail in the independent evaluation report that is attached to my direct testimony as Document No. 2 of my exhibit.

Q. With that understanding of the RSM process, what did you do to calibrate the RSM to Planning and Risk?

A. I reviewed the production cost information that Tampa Electric provided at the start of the project and confirmed that the production costs were, for the most part, exhibiting smooth, correct trends (i.e., they were increasing where they should be increasing and declining where they should be declining). Having verified that the RSM production cost values were "smooth," I was confident that inputting variable cost parameters into the models for similar proposals would yield similar production cost results. Although the RSM is not a detailed model and could not simulate Tampa Electric's production costs with Planning and Risk's accuracy, in the end (after accounting for future portfolio composition and future unit revenue requirement methodology differences), the independent RSM evaluation results tracked Planning and Risk's results reasonably well.

Q. Once the RSM was calibrated, what was the next step?

A. I flew to Tampa for the Proposal Due Date, opened all proposal packages, and retained an electronic copy of each proposal. I read each proposal and participated in discussions with Tampa Electric about interpreting the proposals, identifying areas requiring clarification, and assessing each proposal's compliance with the RFP's Minimum Requirements. Tampa Electric communicated with proposers to seek clarification and corrections to uncertain areas of the proposals, copying me on all email correspondence and encouraging bidders to do the same.

I incorporated pricing and operational information from each proposal into the RSM. Such information included contract commencement and expiration dates, summer and winter capacity, capacity pricing, heat rates, fuel supply assumptions, variable O&M charges, start-up costs, expected forced outage hours, and expected planned outage hours. Most of this information was directly inputted into the RSM. After the initial part of the evaluation, Tampa Electric provided Sedway Consulting with its own modeling results so that Sedway Consulting could cross-check all key modeling assumptions and outputs and ensure consistency with the information in the RSM.

On June 21, 2012, Tampa Electric and Sedway Consulting discussed the evaluation results of the original proposals and agreed that several offers should be shortlisted. The bidders of these offers were engaged in conference calls (which Sedway Consulting monitored) to discuss their bids and respond to questions. These bidders were provided an opportunity to provide best-and-final offers on July 13, 2012.

Q. What were the results of Sedway Consulting's RSM analysis?

A. Using the RSM, Sedway Consulting was able to compare the economics of Tampa Electric's NPGU and each of the proposed resource options (both the original bids and the best-and-final offers). That comparison entailed a calculation of the net present value of each option from 2013 through 2046 and accounted for 1) resources that would need to "fill in" behind options that expired before 2046 and 2) differences in the capacity of each option proposed. The evaluation was performed for a base case set of fuel price and load forecast assumptions, as well as a low fuel price/low load scenario and a high fuel price/high load scenario. Tampa Electric's NPGU was found to be $69 million (cumulative present value of revenue requirements - "CPVRR") less expensive than the next best resource's best-and-final offer under base case assumptions. The results, ranking of resources and additional scenarios are described in detail in Sedway Consulting's independent evaluation report that is attached as Document No. 2 of my exhibit.

Q. What do you conclude about Tampa Electric's solicitation?

A. I conclude that Tampa Electric's NPGU is the most cost-effective resource for meeting Tampa Electric's 2017 capacity needs and concur with Tampa Electric's decision to move forward with that project. The solicitation process yielded the best results for Tampa Electric's customers while treating proposers fairly. The RFP was sufficiently detailed to provide necessary information to proposers. The economic evaluation methodology and assumptions were appropriate and unbiased, and the independent evaluation procedures provided a cross-check of Tampa Electric's proposal representation in Planning and Risk and confirmed Tampa Electric's conclusions. Finally, I conclude that Tampa Electric's NPGU is $69 million CPVRR less expensive than the next best offered resource under base case assumptions.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BY MR. BEASLEY:

Q Would you please summarize your direct testimony?

A Before I get to the summary, if I could point out that I believe there has been a correction, perhaps that's already been filed with the Commission, on the second document of the exhibit.

Q Would you like to identify that for us, please?

A Just to be sure and clear. On page 34 of the original filed exhibit there are two numbers that were changed in a minor way.

In Table A2 it was to reporting clarification. The capacity, levelized capacity price for Proposal B, which is a confidential number, actually increased in the revised number by a penny, and the variable O&M price or charge decreased by a penny.

BY MR. BEASLEY:

Q Thank you. With that change, would you please summarize your direct testimony?

A Yes. Commissioners, good afternoon. Again, I'm Alan Taylor, the President and founder of Sedway Consulting, a firm that specializes in providing independent evaluation services in utility power supply solicitations.

In summarizing my testimony, I'd like to cover three general areas: One, give you a sense of my background and the, and the firm's capabilities; secondly, talk about exactly what tasks Sedway Consulting undertook in Tampa Electric's current solicitation; and third, discuss the findings and overall conclusions from our work.

My background is one of kind of a blend of engineering and business. I've got an undergraduate degree from MIT in energy engineering and an MBA from UC Berkeley with a specialization in finance. I've been in the utility consulting business for almost 30 years; in the early stages really dealing with production cost models and utility simulation models, using them and training others, regulators and utility planners, in how to use these systems.

I've done a lot of work in integrated resource planning and environmental compliance planning, and really in the last 15 years or so a lot of concentrated work in providing independent evaluation services in utility power supply solicitations.

I've overseen dozens of solicitations around the country. I've sat in this chair a number of times with Florida solicitations involving Florida Power & Light and Florida Progress.

As far as the work I've done around the U.S., I've reviewed over a thousand power supply proposals. So I'm very familiar with the evaluation techniques and processes.

Sedway Consulting was retained at the start of Tampa Electric's process. And I reviewed the RFP, provided comments, I participated in the pre-release call in April, and then also flew to Tampa and monitored directly the bidders' conference.

Later on, I worked with Tampa Electric to understand their modeling systems and the assumptions and locked down all those assumptions prior to the bids being received in May. I also was on-site in Tampa when the bids were received. In fact, I did the opening of the proposals; retrieved my own electronic copy of the proposal before turning things over to Tampa Electric for their evaluation.

I also monitor all of the communications back and forth either by phone or by being copied on emails. And I conducted an independent evaluation of all the proposals that were received using Sedway Consulting's proprietary model, the Response Surface Model, or RSM.

As with all solicitations, I was free to employ whatever evaluation methodologies and procedures that I deemed appropriate to ensure a fair and robust evaluation of the offers.

My conclusion of the analysis was that Tampa Electric's Polk 2-5 was the most cost-effective resource for meeting Tampa Electric's 2017 resource need. The next best option was more than $69 million more expensive on a present worth of revenue requirements basis.

I believe in total that the RFP itself was sufficiently detailed, the solicitation process was conducted fairly, and I concur with Tampa's decision, Tampa Electric's decision to move ahead with the Polk 2-5 conversion. That concludes my summary.

MR. BEASLEY: Thank you. We tender Mr. Taylor for cross-examination.

CHAIRMAN BRISÉ: Mr. Wright?

MR. WRIGHT: Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MR. WRIGHT:

Q Good afternoon, Mr. Taylor.

A Good afternoon, Mr. Wright.

Q In evaluating generation expansion options, do you agree that a chosen option should be demonstrated to be the best option over a wide range of sensitivities?

A Yes.

Q And would you agree that, that the wider the range of sensitivities over which an option is shown to be the best the more robust the results are?

A It kind of depends on the range of possibilities that are explored. I think it's important for ultimate decision-makers to have numbers that are, are focused, and I don't know that necessarily more is better as far as providing hundreds or -- several hundred numbers can, can really just make things kind of fuzzy.

Q Do you agree that, that utilities should evaluate purchase options, either PPAs or asset purchases, with the same rigor with which they evaluate self-build options?

A I believe that -- I guess my quick answer would be no in the sense that I believe that it's best to provide a first screening cut at proposals. And if there are proposals that are found to be far out of the money and not very competitive, they don't require the rigor and investigative analysis that those that are closer and more competitive to serve.

Q And with respect to that second category there that you just mentioned, those that are somewhat closer to the, to the cost of the self-build option, would you agree that such options should be evaluated with the same rigor that the utility evaluates its self-build options?

A Yes.

Q And you did personally review all the proposals received in response to Tampa Electric's RFP; correct?

A Yes, I did.

Q This may be obvious since the company did in fact short list DeSoto, but would you agree that DeSoto was a qualified bidder?

A Yes, it was.

Q And that the DeSoto facility is a viable unit that has a proven operating record in the Florida wholesale market?

A I certainly considered it to be a, a well thought out proposal. I am not familiar with the operating history of the resource beyond the statements that DeSoto made in its own proposal submission, but I took those at face value.

Q Did you speak with representatives of DeSoto Generating Company during the process?

A I was on the phone during the short listing phone call that was made with DeSoto, as was the case with all of the short listing phone calls that were made. So, yes, I was monitoring those calls and able to contribute and discuss things as appropriate.

Q Were you involved in -- did you monitor or participate in any phone calls between Tampa Electric and DeSoto regarding clarifications as to DeSoto's original proposal?

A I believe in the short listing process there was a certain amount of discussion for some minor clarifications, and I was party to that, yes.

Q Same question, did you -- or similar question, different time period. Did you participate in any communications, let's say telephone conversations, that involved Tampa Electric representatives and DeSoto representatives with respect to DeSoto's best and final offer?

A I believe there was a call that occurred after the final decision to debrief DeSoto, and I was involved with that phone call.

Q Okay. And when you say after the final decision, that was on or after July 27; is that correct?

A That's correct.

MR. WRIGHT: Okay. Thanks. Mr. Chairman, I would like to ask if Ms. Hopkins would please redistribute what's been marked as Exhibit 30.

CHAIRMAN BRISÉ: Sure.

MR. WRIGHT: DeSoto's best and final offer.

CHAIRMAN BRISÉ: That is a confidential document?

MR. WRIGHT: Yes, sir. It's the first of the two confidential documents.

BY MR. WRIGHT:

Q Mr. Taylor, you've seen this document before, I trust?

A Yes, I have.

Q Okey-doke. I want to ask you a couple of questions basically identical to those that I asked Mr. Rocha.

If you could please look at the content there on lines 10 through 12, but again cautioning you not to articulate exactly what, what it says there.

First question, did you understand the content of what's there as implying that it would remove the risk associated with transmission costs from Tampa Electric and put it on DeSoto?

A I did not. I assumed that this was simply DeSoto retaining the energy dispatch rights, but that it would become an owned asset of Tampa Electric and therefore transmission upgrades would be, would be necessary.

Q But I wanted to specifically ask you about the wheeling costs.

A Uh-huh.

Q Same, same question, did you not understand that it would remove the wheeling charges associated with the capacity from Tampa Electric's account?

A Off the top of my head, I don't recall the adjustment that I made in modeling this second best and final offer transaction.

Q Same question with respect to firm gas transportation costs. Did you understand that it would -- do you understand one way or the other whether the proposal articulated there would remove the gas transportation cost liability from Tampa Electric's account?

A I am pretty sure that I left the firm gas transportation costs in there because I assumed that with Tampa Electric being the owner of the facility, they would be required to have the firm gas transportation contract in place, and that the, what is being contemplated here would be DeSoto retaining energy dispatch rights but not necessarily the cost responsibility for the firm gas contract.

Q Did you ask anyone at DeSoto to clarify the intent of these provisions?

A No, I did not.

Q Do you know whether anyone at Tampa Electric did?

A I do not believe so. If they had, it probably would have been via an e-mail conversation that I would have been copied on. And the primary reason here is I was finding that even with the best and final offer improvements, the resource was not looking very competitive. So, again, there wasn't a need to drill down into some of the finer points.

Q And when you say -- you made the statement "not looking very competitive." That was in your analysis; correct?

A That's correct.

Q Okay. Now, I did want to, want to move on to that. And I guess the easy way to get to the summary result there is to look at your Table A6. That, that is the summary of the cost-effectiveness of all the proposals versus, versus Polk; correct?

A Yes, it is.

Q Okay. And in your base case analysis you show for Proposal B, which as we all acknowledge is DeSoto, a net additional cost of the DeSoto project of $592 million versus Polk; correct?

A That's correct.

Q Okay. I'm going to ask you the same question I asked Mr. Rocha. How could you get such different results than Mr. Rocha's analysis got?

A Sedway Consulting employed a process with the Response Surface Model whereby we did a head-to-head competition on a standalone basis of each of the offers. This is a procedure that we've adopted across the country to ensure that there isn't something in the system analysis that a utility commonly performs, as did Tampa Electric, that might trigger some odd results.

I have seen in other solicitations, for example, where a small 25-megawatt resource might be extremely expensive but, for whatever reason, it fits into a particular niche of an expansion plan and moves another large, rather large unit out by year and causes some amazing cost savings that really are not likely to be achieved given the uncertainties associated with year-to-year load growth and, and a variety of issues.

Computers are very good about calculating things on a very, very specific and, and discrete criterion. So generation expansion plans that are being developed by computers, or even by the people who are looking at a 20.0% reserve margin requirement, will move some of these large units around and create some effects that, that blur the true economics of a resource.

So that's why I have performed as a cross check to what has been done by Tampa Electric a standalone analysis where Tampa Electric effectively looked at Proposal B, the DeSoto acquisition, and the Polk 2-5 conversion on top of each other for most of the 30-year period that was being analyzed.

In my case, I looked at a very stark comparison of the DeSoto transaction for the full 30 years, and the next point generating unit, the Polk 2-5 conversion, for a full 30 years.

So the two comparisons there were looking explicitly at the economics of those resources, and that's, that's why the comparison comes up with a more stark relief and a more, more significant comparison between the, the Proposal B and the next point generating unit.

Q Okay. You mentioned computers. I noticed in reading your testimony and resumé that you used to work with computer production simulations a lot, didn't you, PROMOD and so on at EMA?

A I certainly did, yes.

Q And do you agree with Mr. Rocha's testimony that, that at least for Florida investor-owned utilities the standard mode of analysis is a 30-year CPWRR analysis?

A I would agree with that, yes.

Q Okay. And would you agree that Mr. Rocha's analyses best reflect the real cost to Tampa Electric of the alternate expansion plans evaluated?

A I don't know if that is necessarily true. The, the issue with the RFP was one of deciding whether Tampa Electric should move ahead with the alternative that they put on the table or whether there might be market resources, other bidders that could step in and provide a more cost-effective alternative to that next planned generating unit. That was kind of the question that I sought to answer in my analysis.

Tampa Electric looked at a system analysis where their next planned generating unit was in a fluid position of being able to be shifted or deferred, and at the initial state of the project that was not really something that was discussed.

The, the recognition was that the need was in 2017 and that's when the resource was contemplated to be developed. What they ultimately showed in their numbers with a fluid concept of allowing the resource to be deferred was something that pushed it out a year or two by indeed acquiring the DeSoto CT asset.

Q In your testimony, and I think in your evaluation report as well, you talk about using fill-in units for certain proposals.

A Correct.

Q Did you use any fill-in units in evaluating the DeSoto purchase option?

A No. The fill-in units were associated with power purchase agreements that had a particular termination date. So if there was a ten-year PPA, then in order to be able to compare that to a 30-year next planned generating unit, there was a need to fill in behind it for years 11 through 30.

In the case of the DeSoto transaction, it already was a life of asset transaction that was assumed to be operable clear out through the year 2046, the end of the analysis.

Q Thank you. And your analysis assumed, did it not, that DeSoto would come into Tampa Electric's system as a firm resource June 1 of 2013; correct?

A That's correct.

Q Just to confirm a little bit of earlier testimony, you got your wheeling costs from FPL's OASIS tariff?

A I believe I got it from DeSoto's proposal itself.

Q Okay. And did you get your firm gas transportation costs from Mr. Caldwell or his group?

A Yes. I received two estimates from his group, a low estimate and then a more generous one. And in the case of all the bidders, I selected the lowest ones.

Q And I think based on your earlier testimony that I know the answers to these questions. There aren't many. I'm just going to go ahead and ask you.

Did, did your analysis assign any value to incremental reliability that would be made available by having DeSoto online as early as 2013?

A Effectively it did in the sense that I calculated energy savings in the years 2013 and forward all the way through the end of the study period in 2046 for the DeSoto asset. So there were energy savings associated with Tampa Electric having dispatch rights as of June.

Q And those energy savings would accrue by, by being able to dispatch DeSoto ahead of other CT assets?

A That's correct principally.

Q And also probably avoiding some purchases?

A Correct.

Q That's really an economic gain, not a reliability gain; correct?

A Correct. In, in the sense that there is sufficient capacity for meeting Tampa's current load forecast out until 2017, there was no additional value that was captured there. In fact, that was the case really for all bids throughout the entire time period. Any time there were surplus megawatts above and beyond the 20% reserve margin need, that resource was given no additional value for those megawatts. That was the case, for example, with the Polk 2-5 conversion.

Q Did you include any value for potential capacity revenues from DeSoto in your analyses?

A No. Again, the same assumption was used for all bids. That any, any megawatts above and beyond those that were actually needed to meet the 20% reserve margin were, had no, no particular value.

MR. WRIGHT: Thanks. Could I just have a moment, Mr. Chairman?

CHAIRMAN BRISÉ: Sure.

MR. WRIGHT: Thank you, Mr. Chairman. Thank you, Mr. Taylor. That's all the questions I have.

CHAIRMAN BRISÉ: Ms. Christensen.

MS. CHRISTENSEN: No questions.

CHAIRMAN BRISÉ: Staff?

MS. BROWN: Staff has no questions.

CHAIRMAN BRISÉ: Commissioners? All right. Redirect.

MR. BEASLEY: Very brief redirect, sir.

REDIRECT EXAMINATION

BY MR. BEASLEY:

Q Mr. Taylor, was there anything in the best and final offer letter that you've just been redistributed that would cause you as a reasonable person to inquire about transmission costs?

A No.

Q Given the delta in your analysis between the DeSoto proposal and the Polk conversion, would, would Polk still win if transmission costs were, were added in?

A Absolutely. The, part of the reason why I provided a breakdown of the various costs in my independent evaluation report was to show some background in ultimately what drove a lot of the differentials and allow any reader to back out some of these costs, if they, if they so desired.

But because the cost delta is so significant, it would not be affected by backing out those transmission costs.

MR. BEASLEY: Thank you, sir. That's the only redirect I have.

I would like to move the admission of Exhibit 18, which is Mr. Taylor's exhibit, and then Exhibit 11, which is the need study sponsored by all of Tampa Electric's witnesses.

CHAIRMAN BRISÉ: All right. At this time we'll move Exhibit 18 and 11 into the record, if there are no objections. Seeing none, they're moved into the record.

(Exhibits 11 and 18 admitted into the record.)

And, Mr. Wright, I don't think you had any exhibits other than taking a second look at Exhibit 30.

MR. WRIGHT: Correct, Mr. Chairman. Thank you.

CHAIRMAN BRISÉ: All right. Thank you.

Thank you, Mr. Taylor.

THE WITNESS: Thank you.

CHAIRMAN BRISÉ: Okay. So we are coming to the conclusion of this hearing, and I suppose there probably is going to be discussion of what some of our options may be.

Commissioner Edgar.

COMMISSIONER EDGAR: Thank you, Mr. Chairman.

From reviewing all of the information that we've heard today and that we have before us with the prefiled testimony and the other documents in this docket, I believe it's accurate to say that for Issues 1, 2, 3, and 4 there is not disagreement between the parties, or the corollary, there appears to be agreement between the parties. Which brings us pretty much to 5, 6, recognizing that 7 -- 5 and 6, recognizing that 7 is simply procedural.

I do -- I am not aware of any legal issues that are before us. The disagreement appears to be primarily a difference of opinion about the analysis of some of the financial projections, and so I'm wondering if our staff would be able to take a little bit of time this afternoon and come back, be available for questions, and if a bench decision would be an option to us.

CHAIRMAN BRISÉ: Ms. Helton?

MS. HELTON: In my opinion, whether a bench decision is an option really hinges on Mr. Wright and Ms. Christensen and whether they will waive their right to file a brief.

MS. CHRISTENSEN: Well, I guess for clarification, I didn't look at the notice of hearing. Was it noticed for a bench decision?

MS. HELTON: All notices -- my recollection is that all notices that we enter for a hearing include language that state that a bench decision may be made, but that, that ability of the Commission to do that hinges upon whether all of the parties waive their rights to file a post-hearing filing.

CHAIRMAN BRISÉ: Mr. Wright?

MR. WRIGHT: Mr. Chairman, we have been planning on filing a brief. I cannot commit to waive away that right right now. I'd be happy to confer with my client and respond, but as of right now we are planning to file a brief.

CHAIRMAN BRISÉ: Okay. Would you like some time to confer with your client?

MR. WRIGHT: Yes, please.

CHAIRMAN BRISÉ: Sure. How much time do you need?

MR. WRIGHT: Half an hour, Mr. Chairman.

CHAIRMAN BRISÉ: All right. Well, if that's what you need, but I'm supposing that you probably can do it faster.

MR. WRIGHT: We will try, Mr. Chairman. But it's not, it's not just people who are in this room that have to make this decision.

CHAIRMAN BRISÉ: Understood. Before we get there, Commissioners, any further comments?

Commissioner Balbis.

COMMISSIONER BALBIS: Thank you, Mr. Chairman.

I just want to clarify from Commissioner Edgar, these are just Issues 1, 2, 3, and 4 or --

COMMISSIONER EDGAR: My understanding from the testimony and the opening statements and all of the other documents was that we would still need to make a decision on Issues 1 through 4, but the parties do not appear to have a disagreement on Issues 1 through 4.

In other words, my understanding was that, from Ms. Christensen and from Mr. Wright and from looking at the prefiled position statements, that although the verbiage is different, that the essence of their positions were the same as far as the need.

MR. WRIGHT: Mr. Chairman, if I could just clarify. Issue 3 is the 39-year-old statutory criteria and the need for adequate electricity at a reasonable cost. I believe that ties directly into Issue 5, which is whether the, the proposed alternative is the most cost-effective alternative.

So if we do file a brief, I would expect that we would address Issues 3, 5, and 6. I just want to, want to be clear about that because of the close relationship between 3 and 5. But certainly 5 and 6 are the big ones: Most cost-effective alternative and should you grant the petition.

COMMISSIONER BALBIS: And the reason why I wanted to clarify that is that we still have to come back and go through the process for 5 and 6. I just wanted to confirm that that was the case, unless we can make a bench decision on the others. But it sounds like that's not an option.

COMMISSIONER EDGAR: May I?

CHAIRMAN BRISÉ: Sure.

COMMISSIONER EDGAR: And I'm not trying to, to rush any of my fellow Commissioners. Again, just as I looked at the issues and all of the information before us, it did appear that there seemed to be close to a meeting of the minds of the parties on 1 through 4. We certainly would have the responsibility to vote on those issues as part of this docket. And that then purely from, from my own perspective that the heart of what is before us is in 5 and 6, although I understand the comment that Mr. Wright has made regarding Issue 3. My thinking was because there are no legal issues and there do not seem to be a real factual dispute but more of an analysis dispute, that our staff could maybe take some time and we could individually take some time and then come back at around 4:00, would have been my suggestion, to potentially have a bench decision. But if that does not work, that's -- it was, it was just a question.

CHAIRMAN BRISÉ: Sure.

COMMISSIONER EDGAR: And perhaps a suggestion.

CHAIRMAN BRISÉ: Sure.

Commissioner Graham.

COMMISSIONER GRAHAM: Thank you, Mr. Chairman.

Commissioner Edgar beat me to the punch because when I turned my light on, I was going to make the same suggestion. I probably wouldn't have worded it as eloquently as she did, so I'm glad she did beat me to the punch.

But I'm, I'm prepared to make a bench decision depending on the feedback we get back from DeSoto and the recommendation we get from staff.

CHAIRMAN BRISÉ: Commissioner Brown.

COMMISSIONER BROWN: I would just echo the sentiments by Commissioner Edgar and Commissioner Graham. So I look forward to hearing from Mr. Wright in the next 15 to 30 minutes whether you intend to file a brief. Thank you.

CHAIRMAN BRISÉ: All right. It sounds like there is an interest by the Commission to, to hear back from you. It is now 1:20. I certainly hope to hear back from you by 1:40.

MR. WRIGHT: We will do our best, Mr. Chairman. Thank you.

CHAIRMAN BRISÉ: Prior to that, Commissioner Graham, do you have a question?

COMMISSIONER GRAHAM: I guess procedurally -- I guess this goes to Ms. Helton. If DeSoto wants to file a brief, then I guess the question I'm coming up with, can we make the determination now one way or the other, either on or off, so 15, 30 minutes, 20 minutes from now, half an hour from now, whenever it is, either staff is going to come up with a recommendation and we reconvene here at 4:00, or we're just dismissed from here and we expect the briefs whenever, whenever it's recorded? I mean, rather than us sitting here for half an hour waiting to hear back from them, if we can just make that determination one way or the other.

MS. HELTON: Let me make sure I understand what you're, what you're saying. DeSoto would report back to someone on the staff and say whether they are going, want to file briefs or not. If they want to file briefs, then we would notify everyone that no one will be coming back at 4:00. If they waive their right to file briefs, then we will notify everybody to reconvene at 4:00.

COMMISSIONER GRAHAM: That's exactly what I meant to say.

MS. HELTON: Okay. If everyone agrees to that process, I think that would be, that would work for me.

CHAIRMAN BRISÉ: Okay. Parties, we need to hear from you.

MR. WRIGHT: Pardon? I, I didn't understand your question.

CHAIRMAN BRISÉ: We need to hear from you if what Ms. Helton expressed works.

MR. WRIGHT: Oh, yeah. I understood that. That sounds like exactly the right process to me.

CHAIRMAN BRISÉ: Okay.

MR. WRIGHT: And we'll go do what we need to do.

MS. HELTON: And --

MS. CHRISTENSEN: No objection.

CHAIRMAN BRISÉ: Okay.

MR. BEASLEY: No objections.

MS. HELTON: Mr. Chairman, I should have also put in the category of waiving the right to file briefs, I should have added TECO to that category, too.

CHAIRMAN BRISÉ: Right.

MS. HELTON: So Mr. Beasley and Mr. Wahlen need to have also waived them.

MR. BEASLEY: Thank you.

CHAIRMAN BRISÉ: All right. So we at this point will be at least in recess 'til 1:20. And depending upon the outcome, then -- I mean, 1:40 rather. And depending upon what we receive back, we could stand adjourned or, or come back for a decision. Okay? We will return, as I stated before, at 1:40. Thank you.

(Recess taken.)

All right. Good afternoon. Okay. I have been made aware of some information from our staff, but I'll go ahead and wait to hear from, from the parties.

MR. WRIGHT: Thank you, Mr. Chairman. We were able to confer with the appropriate officials within DeSoto Generating Company, and we are willing to waive our right to file a brief.

And just as an ancillary matter, since we're going to do that, I would ask your leave to withdraw what had been marked as exhibit -- actually it had been admitted now, but I'd like to, you know, withdraw Exhibits 30 and 31, the confidential exhibits, so that, frankly so that we just don't have to spend the time doing the confidential protection paperwork. Thank you.

CHAIRMAN BRISÉ: Okay. Understood.

(Exhibits 30 and 31 withdrawn.)

Ms. Christensen.

MS. CHRISTENSEN: And OPC will waive any brief writing.

CHAIRMAN BRISÉ: Okay. TECO?

MR. BEASLEY: We would waive our right to file a brief. Thank you, sir.

CHAIRMAN BRISÉ: Okay.

MR. WAHLEN: And we don't object to him withdrawing his exhibits.

CHAIRMAN BRISÉ: Okay. Thank you.

MR. WAHLEN: Just to be clear.

CHAIRMAN BRISÉ: All right. So we will withdraw Exhibits 30 and 31.

MR. WRIGHT: Thank you.

CHAIRMAN BRISÉ: All right. We are in the posture of decision, recognizing that one of our Commissioners is not back yet. So I guess we need to confer with his office.

MR. BALLINGER: I -- Chairman Brisé, if I could. Tom Ballinger with staff.

I think Commissioner Balbis is in another staff briefing on the agenda tomorrow and that's where he's at right now. And I would point out, I think we have another briefing scheduled with Commissioner Graham at 4:00.

CHAIRMAN BRISÉ: Right.

MR. BALLINGER: So if you're looking at times to come back, just keep those in, in mind.

I think staff could get something together in

20 or 30 minutes or so and be ready to give you a recommendation through all the issues.

CHAIRMAN BRISÉ: Okay. Okay. We will seek to reconvene at about 3:30, and at that point we should be in the posture to receive staff's recommendation and then make a decision. All right?

We are in recess until 3:30. Thank you.

(Brief pause.)

Folk, you all may have, you all may be inclined to hear what we have to say. So if you -- and we're going to go ahead and go back on the record at this time.

Okay. Ms. Christensen heard us, I guess, so she's coming back in.

Okay. I think we need about a minute for us to line up with our computer system and court reporter and so forth.

But I think there may be a possibility that we may be in the posture to, to move forward with a bench decision even before the staff recommendation comes back in. Okay?

So I don't know if any of my fellow Commissioners want to make comments and then possibly entertain a motion.

Commissioner Edgar.

COMMISSIONER EDGAR: Thank you, Mr. Chairman. Looking at the issues before us, again my understanding is that there is close to consistent agreement on the resolution of Issues 1, 2, 3, and 4, recognizing that there are, in the proposed issue positions or in the issue positions that were filed by the parties are some differences in wording and dicta basically that it would be our choice as to whether to adopt or not.

Generally, and my approach is, is, you know, the fewer words the better sometimes. So looking at the issues before us specifically, I would consider the answer to Issue 1 to be yes; the answer to Issue 2 to be no; the answer to Issue 3, yes; Issue 4, yes; Issue 5, yes; Issue 6, yes; Issue 7, yes. In other words, yes on all issues except for 2, which is worded slightly differently, so the answer would be in the negative on that one.

COMMISSIONER GRAHAM: Second.

CHAIRMAN BRISÉ: All right. So we have a motion and it's been seconded.

Comments. Commissioner Brown.

COMMISSIONER BROWN: Thank you, Mr. Chairman. And I think based on the prefiled testimony and the testimony we heard here, I'm excited about this conversion, this combined cycle conversion. I think it's not only the most cost-effective alternative, it's going to provide fuel savings and it lowers the environmental emissions rate. I'm really looking forward to it, and I think that you guys have a good plan in place. So looking forward to it. I support the motion.

CHAIRMAN BRISÉ: Commissioner Balbis.

COMMISSIONER BALBIS: Thank you, Mr. Chairman. And I fully support the motion and echo similar comments of Commissioner Brown. I think on top of the positive aspects that she mentioned, I think that any time upgrading these power plants to more effective and efficient processes, reducing emissions, and also something that's close to my heart is the utilization of treated waste water for cooling purposes, also preserving another resource that's important to this state. So with that, I fully support the motion.

CHAIRMAN BRISÉ: Thank you. Commissioner Edgar.

COMMISSIONER EDGAR: Thank you. I would just add that I certainly recognize from the information that is contained in this docket that DeSoto does have an asset, you know, in this state, and would encourage the two operators to continue discussions as appropriate that would be in the best interests of the ratepayers as other needs occur in the future.

CHAIRMAN BRISÉ: All right. Any further comments? At this point I think we are in a position to vote. So it's been moved and seconded. We've had ample discussion. All in favor, say aye.

(Vote taken.)

Thank you very much. We stand adjourned.

(Proceeding adjourned at 1:53 p.m.)

STATE OF FLORIDA)
: CERTIFICATE OF REPORTER
COUNTY OF LEON)

I, LINDA BOLES, RPR, CRR, Official Commission Reporter, 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' attorneys or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 19th day of December, 2012.

Linda Boles

LINDA BOLES, RPR, CRR
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