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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

PETITION FOR DETERMINATION OF NEED FOR CITRUS COUNTY COMBINED CYCLE POWER PLANT, BY DUKE ENERGY FLORIDA, INC. — DOCKET NO. 140110-EI

PETITION FOR DETERMINATION OF COST EFFECTIVE GENERATION ALTERNATIVE TO MEET NEED PRIOR TO 2018, BY DUKE ENERGY FLORIDA, INC. — DOCKET NO. 140111-EI

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VOLUME 4

Pages 378 through 659

PROCEEDINGS: HEARING

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

DATE: Wednesday, August 27, 2014

TIME: Commenced at 9:34 a.m.
Concluded at 9:57 a.m.

PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida

REPORTED BY: LINDA BOLES, CRR, RPR
Official FPSC Reporter
(850) 413-6734

APPEARANCES: (As heretofore noted.)

I N D E X

WITNESSES

NAME:	PAGE NO.
BENJAMIN BORSCH	
Examination by Mr. Walls	381
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Prefiled Rebuttal Testimony Inserted	479
Prefiled Direct Testimony Inserted	515
Prefiled Rebuttal Testimony Inserted	567

EXHIBITS

NUMBER:	ID.	ADMTD.

(REPORTER'S NOTE: No exhibits identified and/or admitted in this volume.)

P R O C E E D I N G S

(Transcript follows in sequence from Volume 3.)

CHAIRMAN GRAHAM: Okay. Good morning, everyone. We have quite a bit to get done, so we might as well get started.

Let the record show it is August the 27th, and this is our second day of hearing for Docket Number 140110 and parts of Docket 140111.

Okay. Duke, I believe we are up to your last and final witness.

MR. WALLS: Good morning, Commissioners. We call Mr. Borsch to the stand.

Whereupon,

BENJAMIN BORSCH

was called as a witness on behalf of Duke Energy Florida and, having first been duly sworn, testified as follows:

EXAMINATION

BY MR. WALLS:

Q Mr. Borsch, will you please introduce yourself to the Commission and provide your business address.

A Yes. My name is Benjamin Borsch, and my business address is 299 First Avenue North, St. Petersburg, Florida 33701.

Q And you have -- have you already been sworn in as a witness?

A Yes, I have.

Q And can you explain who you work for and what your position is with the company?

A Yes. I work for Duke Energy Florida. I am the Director of Integrated Resource Planning and Analytics.

Q And have you filed direct and rebuttal testimony and direct and rebuttal exhibits in Dockets Numbers 140110-EI and 140111-EI?

A Yes, I have.

Q And do you have your prefiled direct testimony and exhibits and your prefiled rebuttal testimony and exhibits with you?

A Yes, I do.

Q And other than the changes that you filed in your errata on August 20th in Docket 140110-EI and on August 21 in Docket 140111-EI, do you have any changes to make to your prefiled direct and rebuttal testimony and exhibits?

A No, I do not.

Q Okay. And other than those changes in the errata that was filed in those dockets, if I asked you the same questions in your prefiled direct and rebuttal testimonies today, would you give the same answers that are in your prefiled direct and rebuttal testimony?

A Yes.

MR. WALLS: At this time we would request that the prefiled direct testimony and rebuttal testimony of Mr. Borsch in Dockets 140110-EI and 140111-EI be entered into the record as if read here today.

CHAIRMAN GRAHAM: We will enter Mr. Borsch's --

MS. RULE: Chairman, I have an objection.

CHAIRMAN GRAHAM: Okay.

MS. RULE: Duke has withdrawn the major part of its request in Docket 140111. The bulk of Mr. Borsch's testimony in that docket, particularly his rebuttal testimony, relates to the offers by Calpine and NRG that are no longer on the table. Also, there are a good deal of sensitive and confidential exhibits, particularly to the rebuttal testimony, that we would object coming into the record, and I realize that's not happening right now.

But we would ask that Duke specify the exact portions of Mr. Borsch's direct and rebuttal testimony that relate only to its pending request. The rest is irrelevant and surplusage and should not come into the record. Thank you.

CHAIRMAN GRAHAM: Duke?

MS. TRIPLETT: Mr. Chairman, some of the rebuttal testimony in the 111 docket addresses NRG's witness Mr. Pollock's testimony, and that is still an issue in the case. If, if the Commission would like us to go through, I thought for ease where it made sense if there were testimonies that were combined, that we were going to just put them in in their entirety.

But if it's -- if I need to go back and try and figure out which parts are, you know, related to Mr. Pollock's testimony and which part are related to the Suwannee portion, I would have -- I need some time. So we'd probably just need to do the direct testimony at this point and then go back and, and get the rebuttal in, but --

CHAIRMAN GRAHAM: Mary Anne, if, if I basically just state that we're only going to take into account those parts of the rebuttal that directly deal with Mr. Pollock's, is that enough, or do we have to go back and actually identify that part in the rebuttal testimony?

MS. HELTON: The problem with that approach is it may be a little bit ambiguous, and what may to me appear to belong to Mr. Pollock may not appear to Mr. Cavros to belong to Mr. Pollock, not picking on Mr. Cavros. But I'm not sure that that will work.

You know, part of the problem too is we say in our Order Establishing Procedure that if you want to strike certain testimony, that you need to do so by the time of the Prehearing Conference. But obviously Ms. Rule couldn't do that because we didn't know until yesterday morning that the case was going to essentially change.

So this is -- doing things like that and making changes like that at the last minute makes it hard to administratively and efficiently deal with the case.

CHAIRMAN GRAHAM: So your suggestion would be?

MS. HELTON: My suggestion would be that if you agree with Ms. Rule that there are certain portions of the witness's that should not come into the record because it is now irrelevant, that Ms. Triplett be given time to designate which pages and which lines should be stricken and should not be included in the record.

MR. WALLS: Can I add something to this, if I might?

CHAIRMAN GRAHAM: Sure.

MR. WALLS: One, she mentioned the confidentiality concern, and we would definitely preserve confidentiality, as we've agreed with them throughout. So that shouldn't be a concern for them anymore.

Two, I fail to see the prejudice of the testimony coming in to NRG since they have withdrawn their testimony on this, we have withdrawn Suwannee, and we will be bringing back that project to this Commission, whether it's Suwannee or the Calpine Osprey plant acquisition, and everybody at this table will be able to refile whatever they want to refile and present that to the Commission.

So I don't really see a prejudice to her to having this in this record at this point in time. That issue has been withdrawn on Suwannee CT. It's not going to be addressed by the Commission. And she's withdrawn her case on that, so I don't see the prejudice. And so we would protect the confidentiality. She would be able to refile anything she wants. The issue only is on the Hines chiller in the little GBRA docket, and I trust that the staff and the Commission can go through the testimony and identify the relevant parts for that remaining issue on Hines chiller.

CHAIRMAN GRAHAM: Ms. Rule.

MS. RULE: A couple of comments. I think this whole discussion emphasizes my objection the other day to separating out Hines from Suwannee. It was presented as a package deal, and now you hear Duke saying we can't pull it apart, can't pull the testimony apart. We put it in together. I understand that, because that's I why I was objecting to separating the Hines request from the Suwannee request yesterday.

But in any event, and I don't want to unduly hold up the proceeding, I think if Duke would agree to withdraw its direct Exhibits 8 through 15 and rebuttal Exhibits 12 to 19, I think we could probably proceed on that basis.

MR. WALLS: A brief response?

CHAIRMAN GRAHAM: Do you need time to look at it or --

MR. WALLS: Well, we'll look at it, but I would just like to correct the statement that these were a package deal. That's not true, and Mr. Borsch can address that.

CHAIRMAN GRAHAM: Are you okay with those exhibits that she mentioned?

MR. WALLS: We have to look at it. If we could have just a moment to look at them and make sure we're --

CHAIRMAN GRAHAM: All right. I'll give you five minutes, Art Graham time.

(Pause.)

Ms. Rule, could you give me those exhibits again.

MS. RULE: Yes, sir. Those would be direct Exhibits 8 through 15. I'm sorry. I've got those numbers wrong. The rebuttal exhibits, actually it would be Exhibits 8 through 19.

CHAIRMAN GRAHAM: Exhibits 8 through 19?

MS. HELTON: As numbered in his testimony, not as numbered on the Comprehensive Exhibit List.

MS. RULE: Okay. Yes, as numbered on the testimony.

CHAIRMAN GRAHAM: Which would be Exhibits 69, 70, 71, 72, 125, 126, 127, 128, 129, and 130.

(Pause.)

MR. REHWINKEL: Mr. Chairman, for those of us keeping score, are we going to re-inventory exactly what are at issue based on the exhibit list?

CHAIRMAN GRAHAM: Well, I'm going to hear, I'm going to hear what Duke has to say about her request. They may come back with okay everything but this, but we'll go through the final inventory before we enter.

MR. REHWINKEL: Thank you.

MS. TRIPLETT: So I'm going to use the hearing exhibit numbers as they're marked on the list. So we can agree to withdraw or not enter into the record Numbers 69, 70, 71, and 72. Those are all, those are the direct testimony exhibits. And then the rebuttal, we can agree to 127, 129, 130, and 134.

For the ones that are not included in the rebuttal list that Ms. Rule requested, the reason is because we anticipate that during questioning it may be helpful to refer to the structure of particular deals so that we do not reveal confidential information in the public forum. And that information is for Calpine in any event. It's not information regarding NRG, those exhibits.

CHAIRMAN GRAHAM: So you're agreeing to everything that was requested except for 128, 131, 132, and 133; is that correct?

MS. TRIPLETT: Yes, sir.

CHAIRMAN GRAHAM: Actually I'm not even sure 134 was requested but you agreed to it anyway.

MS. RULE: We did request 134.

CHAIRMAN GRAHAM: Oh, did you?

MR. REHWINKEL: I would like to be heard about 134.

CHAIRMAN GRAHAM: Okay. Because I --

MR. REHWINKEL: At the right time.

CHAIRMAN GRAHAM: Ms. Rule, I thought you said --

MS. RULE: We'll withdraw objection to 134.

CHAIRMAN GRAHAM: Okay. So 134 is still in.

MS. TRIPLETT: And that's fine with us.

CHAIRMAN GRAHAM: Okay. Available. We won't enter it in until afterwards.

MS. RULE: And I want to make sure I understand Duke's proposal. Is that to not withdraw -- let me make sure I understand -- 128, 131, 132, and 133?

CHAIRMAN GRAHAM: That is correct.

MS. RULE: Okay. And the reason was those are all exhibits regarding Calpine's offer.

MS. TRIPLETT: That's right.

MS. RULE: I would suggest that perhaps they not be withdrawn at this time. And if they turn out to be relevant to questioning, then I will withdraw my objection to them at that time.

CHAIRMAN GRAHAM: Okay. Because, I mean, we will put them in at the end of the cross-examination so we can make further determination at that time, but we'll let you know. We'll keep the fact that you object to that --

MS. RULE: Along that same line, I do have a suggestion. Given that this is an unusual situation, perhaps you would consider leaving the record open and asking Duke to file a revised strikeout version of their testimony so we can be clear for post-hearing briefs what's in the record and what's not.

CHAIRMAN GRAHAM: Mary Anne.

MS. HELTON: Mr. Chairman, I think that request might be little bit premature. We don't know what this witness is going to be asked about this morning. At the beginning of the hearing, I think that we talked about giving some latitude with respect to what the witness would, you know, be asked and what the witness could testify to. So my suggestion is that you kind of keep that on the back burner and let's see what the testimony is all about before you make a ruling on them.

MS. RULE: Fair enough.

CHAIRMAN GRAHAM: Okay. Okay. Duke. We are entering his prefiled direct testimony into the record as though read. And how do I go about with the, Mary Anne, the rebuttal direct testimony -- the rebuttal testimony?

MS. HELTON: Maybe we can, you can enter it conditionally, and it may be subject to change with respect to after, after the cross-examination period, and there may be some prefiled testimony withdrawn.

CHAIRMAN GRAHAM: What she said. Okay.

MR. WALLS: Okay. Are we ready to move on?

CHAIRMAN GRAHAM: Yes.

MR. WALLS: Thank you.

IN RE: PETITION FOR DETERMINATION OF NEED

BY DUKE ENERGY FLORIDA

FPSC DOCKET NO. ________

DIRECT TESTIMONY OF BENJAMIN M. H. BORSCH

I. INTRODUCTION AND QUALIFICATIONS.

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

A. My name is Benjamin M. H. Borsch and I am employed by Duke Energy Corporation. My business address is 299 1st Avenue North, St. Petersburg, Florida.

Q. Please tell us your position with Duke Energy and describe your duties and responsibilities in that position.

A. I am the Director, IRP & Analytics – Florida. In this role, I am responsible for resource planning for Duke Energy Florida, Inc. ("DEF" or the "Company"). I am responsible for directing the resource planning process in an integrated approach to finding the most cost-effective alternatives to meet the Company's obligation to serve its customers in Florida. As a result, we examine both supply-side and demand-side resources available and potentially available to the Company over its planning horizon, relative to the Company's load forecasts, and prepare and present the annual Duke Energy Florida Ten-Year Site Plan ("TYSP") documents that are filed with the Florida Public Service Commission ("FPSC" or the "Commission"), in accordance with the applicable statutory and regulatory requirements. In my capacity as the

Director, IRP & Analytics –Florida, I oversaw the completion of the Company's most recent TYSP document filed in April 2014 and the Company's 2013 TYSP. I was also responsible for the Company's request for proposals ("2018 RFP") to meet the Company's reliability needs commencing in the summer of 2018 consistent with Commission rule 25-22.082, F.A.C. (the "Bid Rule") and the Company's evaluation of the proposals received in response to that 2018 RFP.

Q. Please summarize your educational background and employment experience.

A. I received a Bachelor's of Science and Engineering degree in Chemical Engineering from Princeton University in 1984. I joined Progress Energy in 2008 supporting the project management and construction department in the development of power plant projects. In 2009, I became Manager of Generation Resource Planning for Progress Energy Florida, Inc. and, following the 2012 merger with Duke Energy, I accepted my current position with the Company. Prior to joining Progress Energy, I was employed for more than five years by Calpine Corporation where I was Manager (later Director) of Environmental Health and Safety for Calpine's Southeastern Region. In this capacity, I supported development and operations and oversaw permitting and compliance for several gas-fired power plant projects in nine states. I was also employed for more than eight years as an environmental consultant with projects including development, permitting, and compliance of power plants and transmission facilities. I am a professional engineer licensed in Florida and North Carolina.

II. PURPOSE AND SUMMARY OF TESTIMONY.

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

A. I am testifying on behalf of Duke Energy Florida in support of its Petition for Determination of Need for the Citrus County Combined Cycle Power Plant. I will introduce all of the Company's witnesses in the proceeding. I will also provide an overview of the Citrus County Combined Cycle Power Plant that the Company proposes to build. I will discuss DEF's Integrated Resource Planning ("IRP") process and how that process led the Company to identify the Citrus County Combined Cycle Power Plant as its next-planned generation. I will also explain the Company's need for the Citrus County Combined Cycle Power Plant, and describe the steps the Company has taken to seek out available, superior supply-side alternatives through the 2018 RFP process. I will describe the Company's 2018 RFP for supply-side alternatives to its next planned generating unit ("NPGU"), I will provide the Company's evaluation of the competing proposals received in response to that 2018 RFP, and I will explain why the Company's NPGU, its Citrus County Combined Cycle Power Plant, is the most cost-effective alternative to meet the Company's reliability needs commencing in 2018. I will conclude my testimony by explaining the Company's decision to proceed with the Citrus County Combined Cycle Power Plant, consistent with the factors in Section 403.519(3), Florida Statutes. More detailed information concerning the Company's decision to build the Citrus County Combined Cycle Power Plant is contained in the Company's Need Determination Study for the Citrus County Combined Cycle Power Plant included as Exhibit No. ___ (BMHB-1) to my testimony.

Q. Are you sponsoring Duke Energy Florida's Need Study?

A. Yes. In general, I am the sponsor of the Need Study. The Need Study was prepared under my direction, and it is true and accurate.

Q. Is the process you outlined in the purpose of your testimony in this proceeding consistent with the 2013 Settlement Agreement?

A. Yes. The Company explained in the Revised and Restated Stipulation and Settlement Agreement ("2013 Settlement Agreement") that the Company projected a need for additional generation capacity in 2018, and that the Company may petition the Commission for a need determination for additional generation, not to exceed 1,800 MegaWatts ("MW"), to be placed in service in 2018 to meet that need. The Company's decision to select the 1,640 MW Citrus County Combined Cycle Power Plant as its NPGU; to solicit competing proposals to the NPGU to determine the most cost effective generation alternative to meet the Company's generation capacity need in 2018; and to file the current Company Petition with the Commission, is consistent with the process the Company identified in the 2013 Settlement Agreement. DEF has met with the parties to the 2013 Settlement Agreement several times to explain this process for meeting DEF's generation needs in 2018 and, ultimately, DEF's decision to meet that need consistent with that process. No party to the 2013 Settlement Agreement has expressed to DEF that DEF has not complied with the 2013 Settlement Agreement.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. I am sponsoring the following exhibits to my testimony:

- Exhibit No. ___ (BMHB-1), the Company's Need Study for the Citrus County Combined Cycle Power Plant;
- Exhibit No. ____ (BMHB-2), the Company's April 2014 TYSP;
- Exhibit No. ___ (BMHB-3), DEF's projected summer peak load growth and Reserve Margins with and without additional generation resources through 2018;
- Exhibit No. ___ (BMHB-4), DEF's projected net energy for load growth on DEF's system;
- Exhibit No. ___ (BMHB-5), a comparison of the cost efficiency of commercially available generation technologies including combined cycle generation technology;
- Exhibit No. ___ (BMHB-6), a map of the location of unconventional shale gas developments and major gas pipelines in the Southeast United States;
- Exhibit No. ___ (BMHB-7), a chart of the recent, current, and future production from both conventional and unconventional North American gas supply resources;
- Exhibit No. ___ (BMHB-8), a map showing the location of the Sabal Trail Transmission LLC ("Sabal Trail") natural gas pipeline and the other natural gas pipelines into the State of Florida;
- Exhibit No. ___ (BMHB-9), a flow chart of the 2018 RFP evaluation process;

- Exhibit No. ___ (BMHB-10), a table of the 2018 RFP Threshold Requirements;
- Exhibit No. ___ (BMHB-11), a table of the 2018 Minimum Technical Requirements;
- Exhibit No. ___ (BMHB-12), a table of the 2018 RFP bidder proposal resource scenarios evaluated in the Company's 2018 RFP evaluation process;
- Exhibit No. ___ (BMHB-13), a table of the results of the Company's Initial Detailed Evaluation of the 2018 RFP bidder proposal resource scenarios; and
- Exhibit No. ___ (BMHB-14), a table of the results of the Company's Detailed Evaluations of the 2018 RFP bidder proposal resource scenarios and the Company's sensitivity analyses in its 2018 RFP evaluation.

Each of these exhibits was prepared under my direction and control, and each is true and accurate.

Q. Please give an overview of the Company's presentation in this proceeding.

A. In addition to my own testimony, the Company will present the testimony of the following witnesses in support of its petition for determination of need for the Citrus County Combined Cycle Power Plant:

- Mr. Mark Landseidel will testify about the site and unit characteristics for the Citrus County Combined Cycle Power Plant, including the size, equipment configuration, fuel type and supply modes; the estimated costs of the Plant; and the Plant's projected in-service date;

- Ms. Amy Dierolf will describe the Citrus County site, discuss the environmental benefits of the site and the Citrus County Combined Cycle Power Plant, and describe the environmental approval process associated with the construction and operation of the Plant;
- Mr. Jeffrey Patton will discuss the Company's fuel supply plan for the Citrus County Combined Cycle Power Plant;
- Mr. Kevin Delehanty provides the Company's fuel forecast and describes the development of that forecast;
- Mr. Ed Scott will discuss the transmission requirements for the Citrus County Combined Cycle Power Plant and the transmission requirements for the proposals submitted in response to DEF's 2018 RFP; and
- Mr. Alan Taylor with Sedway Consulting, Inc. will provide testimony as the independent monitor retained by DEF to ensure the 2018 RFP process was fair and impartial and that the 2018 RFP documents were clear, fair, and consistent with Commission rules. Mr. Taylor was also retained as an independent evaluator of the 2018 RFP bid proposals and will provide testimony that DEF's evaluation of the proposals received in response to the 2018 RFP was fair and impartial and that the Company's selection of the Citrus County Combined Cycle Power Plant NPGU as the most cost-effective option to meet DEF's reliability need was reasonable.

Q. Please summarize your testimony.

A. DEF needs additional generation capacity in 2018 to reliably serve its customers. Improving customer and peak demand growth in Florida following the recession contribute to this need, but the need is primarily driven by current and planned DEF generation plant retirements that exceed the Company's MW reliability need in 2018. Largely as a result of these plant retirements, there are no cost-effective demand-side resources available to the Company that can offset or defer the Company's need for additional generation capacity to meet this reliability need. DEF's plant retirements in Citrus County lead to Florida electric grid reliability issues too, if additional generation is not added in Citrus County.

The Company identified the Citrus County Combined Cycle Power Plant as its NPGU to meet this reliability need after conducting a careful screening of various supply side alternatives in its resource planning process. The Citrus County Combined Cycle Power Plant is a highly efficient, state-of-the-art natural-gas fired combined cycle generation plant located on a favorable site in Citrus County that takes advantage of adjacent DEF site infrastructure and transmission facilities that contribute to the cost effectiveness of the NPGU for DEF's customers.

DEF solicited competing alternatives to its NPGU through its 2018 RFP and no bidder in response to the 2018 RFP proposed a plant that came close to matching the benefits of the Citrus County Combined Cycle Power Plant for DEF's customers. The Citrus County Combined Cycle Power Plant is clearly the most cost effective generation resource for DEF's customers.

The Citrus County Combined Cycle Power Plant allows DEF to maintain its electric system reliability and integrity and to provide its customers with adequate electricity at a reasonable cost in the most cost-effective manner. The Plant further modernizes and adds diversity to DEF's generation fleet in terms of natural gas fuel supply diversity, technology, age, and functionality of the Plant. For all these reasons, DEF requests Commission approval of its Petition for Determination of Need for the Citrus County Combined Cycle Power Plant.

III. OVERVIEW: CITRUS COUNTY COMBINED CYCLE POWER PLANT.

Q. Please describe the Citrus County Power Plant.

A. The Citrus County Combined Cycle Power Plant will be a state-of-the-art, natural gas-fired, combined cycle power plant with an expected summer rating of 1,640 MW and an expected winter rating of 1,820 MW when completed in December 2018. Construction of 820 MW of the 1,640 MW plant will be completed by June 2018, with the remaining 820 MW completed by December 2018. The plant will be highly efficient with high availability for operation on DEF's system. More details about the Citrus County Combined Cycle Power Plant, and its construction and operating characteristics, are provided by Mr. Landseidel in his direct testimony in this proceeding.

Q. Where will the Company build the Citrus County Combined Cycle Power Plant?

A. DEF will build the Plant at a new site in Citrus County, Florida next to the Company's existing Crystal River Energy Complex ("CREC"). The site is a 400 acre parcel bounded on the west by the CREC site. The southern boundary of the site is the current Power Line Road running east to west into the CREC.

The Company will seek Site Certification from the Florida Department of Environmental Protection ("FDEP") and the Florida Siting Board for the Citrus

County site in order to build the Citrus County Combined Cycle Plant. The Company's Site Certification application for the Plant site will be filed with the FDEP in August 2014. This process is described in more detail in the direct testimony of Amy Dierolf in this proceeding.

Q. Are there advantages to building the Citrus County Combined Cycle Power Plant adjacent to the CREC?

A. Yes. The location of the plant adjacent to the CREC allows the Company to use existing CREC infrastructure for the development, construction, and operation of the Plant. This infrastructure provides construction and operational synergies that result in construction and operation cost efficiencies for the Plant compared to typical green field sites.

The most significant infrastructure synergies arise from the existing transmission infrastructure near the site that is now available for transmitting the power from the Citrus County Combined Cycle Power Plant to DEF's system because of the Company's current and planned CREC generation facility retirement decisions. The retirement of the Company's nuclear power plant at the CREC, and the planned retirement of the Company's oldest, coal-fired power plants at the CREC by the time the Citrus County Combined Cycle Power Plant achieves commercial operation, frees up transmission capacity on the existing transmission infrastructure for the Citrus County Combined Cycle Power Plant capacity. As a result, no transmission system upgrades or additions are necessary to add the Citrus County Combined Cycle Power Plant to the Company's system. The only expected transmission costs are the costs necessary to connect the Citrus County Combined Cycle Power Plant to Florida's interconnected electrical grid. The ability to add the Citrus Country Combined Cycle Power Plant to DEF's system without transmission system additions or modifications is one of the synergistic benefits from constructing the Citrus County Combined Cycle Power Plant at the Citrus County site.

Other synergistic benefits include the ability to use the existing CREC intake canal as the water source for the sea water cooling towers for the Citrus County Combined Cycle Power Plant. DEF will also be able to use the existing CREC fresh water wells for process make up water. These CREC resources allow DEF to avoid development and construction costs to provide the make-up water required to cool the Plant and to operate the facility, thus, lowering the cost to construct and operate the Citrus County Combined Cycle Power Plant at the Citrus County site compared to other green field sites.

DEF will also be able to use the existing roads, buildings and other structures at the CREC during the construction and operation of the Citrus County Combined Cycle Power Plant. These synergistic benefits from locating the Citrus County Combined Cycle Power Plant adjacent to the CREC are explained further by Mr. Landseidel in his direct testimony. All of these existing infrastructure resources provide cost-savings synergies for the construction and operation of the Citrus County Combined Cycle Power Plant at the Citrus County site compared to other green field sites.

Q. What will it cost to build the Citrus County Combined Cycle Power Plant?

A. The cost to build the Citrus County Combined Cycle Power Plant is estimated to be $1,350 million (nominal dollars), plus $164 million (nominal dollars) for Allowance for Funds Used During Construction ("AFUDC"), for a total cost of $1,514 million. This includes the cost of equipment; the Engineering, Procurement, and Construction ("EPC") contract; licensing; and internal costs such as construction management and start-up costs.

Q. Is the Citrus County Combined Cycle Power Plant the most cost-effective resource for DEF and its customers?

A. Yes. We believe that the Citrus County Combined Cycle Power Plant will enable the Company to meet the reliability needs of our customers, it will provide a superior source of efficient, cost-effective power to our customers during its life, and that it adds flexibility to the energy production resources on the DEF system. There simply is no more cost-effective, viable generation resource to meet DEF's capacity needs beginning in 2018 to provide reliable power to DEF's customers.

IV. THE COMPANY'S RESOURCE PLANNING PROCESS.

Q. Please explain DEF's Resource Planning Process.

A. The Resource Planning process is an integrated process in which the Company seeks to optimize its supply-side options along with its demand-side options into a final, integrated optimal plan, designed to deliver reliable, cost-effective power to DEF's customers. We evaluate the relationship of demand and supply against the

Company's reliability criteria to determine if additional capacity is needed during the planning period. The generation plan is optimized after including cost-effective DSM programs to establish the most cost-effective overall plan, which becomes the Company's Integrated Optimal Plan. This optimal plan is presented to the Commission in April each year in the Company's annual TYSP filing. The April 2014 TYSP is included as Exhibit No. ___ (BMHB-2) to my direct testimony. The Company's IRP process is also described in more detail in the Need Study attached as Exhibit No. ___ (BMHB-1) to my testimony.

Q. What are the reliability standards the Company used to determine the need for additional resources?

A. DEF plans its resources in a manner consistent with utility industry planning practices, and employs both deterministic and probabilistic reliability criteria in the resource planning process. The Company plans its resources to satisfy a minimum Reserve Margin criterion and a maximum Loss of Load Probability ("LOLP") criterion. DEF has used dual reliability criteria in its IRP process since the early 1990s. DEF's resource plans, based on these dual-reliability criteria, have been reviewed by the Commission each year since the early 1990s in the annual TYSP review process. By using both the Reserve Margin and LOLP planning criteria, DEF's resource portfolio is designed to have sufficient capacity available to meet customer peak demand, and to provide reliable generation service under all expected load conditions.

Q. Why are reserves needed?

A. Utilities require a margin of generating capacity above the firm demands of their customers in order to provide reliable electric service. Periodic scheduled outages are required to perform maintenance and inspections of generating plant equipment. Also, at any given time during the year, some plants will be out of service due to unanticipated equipment failures resulting in forced outages of generation units. Adequate reserves must be available to accommodate these outages and to compensate for higher than projected peak demand due to load forecast uncertainty and abnormal weather. In addition, some capacity must be available for operating reserves to maintain the balance between supply and demand on a moment-to-moment basis. For all these reasons DEF plans generating capacity reserves into its optimal resource plan.

Q. What is DEF's minimum planning Reserve Margin?

A. DEF's minimum Reserve Margin threshold is 20 percent. The Commission established this Reserve Margin threshold for the investor-owned utilities in peninsular Florida in Order No. PSC-99-2507-S-EU. The Reserve Margin is a deterministic measure of reliability.

Q. What is LOLP and what does it measure?

A. LOLP is a probabilistic reliability criterion that measures the probability that a utility will be unable to meet its load throughout the year. The Reserve Margin considers only the peak load and amount of installed resources, while the LOLP considers these factors and takes into account a utility's load shape, generating unit sizes, capacity mix, maintenance scheduling, unit availabilities, and capacity assistance available from other utilities. A standard probabilistic reliability threshold commonly used in the electric utility industry, and the criterion employed by DEF, is a maximum of one day in ten years loss of load probability.

Q. Do both criteria drive the decision to add additional resources?

A. Generally, the need for additional resources will be required by the Reserve Margin criterion before the LOLP criterion is reached. That is the case for the Company's need for additional generation resources in 2018. This reliability need is driven by DEF's commitment to meet the 20 percent Reserve Margin for its customers.

Q. Can you describe DEF's Resource Planning process?

A. Yes. The IRP process begins with the forecast of system load growth that is developed for the next ten years. This forecast draws on the collection of certain input data, such as population growth, fuel prices, interest and inflation rates, and the development of economic and demographic assumptions that impact future energy sales and customer demand. The Company regularly updates its load forecast during the course of the year and for the development of the resource plan presented in the Company's annual TYSP. The development of the Company's load forecast for its 2018 RFP and current 2014 TYSP is explained in more detail in the Company's Need Study in Exhibit No. ___ (BMHB-1) and in the Company's 2014 TYSP included as Exhibit No. ___ (BMHB-2) to my testimony.

Q. What were the results of the Company's load forecasts?

A. By the summer of 2018, when the Citrus County Combined Cycle Power Plant is projected to first come on-line, the summer peak demand is projected to grow to 9,439 MW and by the next summer, when the Citrus County Combined Cycle Power Plant is expected to be fully operational, the summer peak demand is projected to reach 9,813 MW. The annual growth in peak summer demand is approximately 1.4 percent over the current ten year forecast period. This peak summer demand growth results in a summer Reserve Margin of 11.7 percent by 2018 without additional resources to DEF's system. This result is depicted in Exhibit No. ___ (BMHB-3) to my direct testimony.

DEF maintains its Reserve Margin for both its summer and winter peak demands to ensure that DEF provides reliable electric service to its customers. DEF needs additional generation in the summer of 2018 to meet its 20 percent minimum Reserve Margin commitment. Exhibit No. ___ (BMHB-3) shows DEF's forecast of summer peak demand and reserves, with and without the Citrus County Combined Cycle Power Plant generation capacity addition. As demonstrated in this exhibit, without the Citrus County Combined Cycle Power Plant generation capacity addition, DEF's summer Reserve Margin will decrease to 11.7 percent in the summer of 2018 and 6.9 percent by the summer of 2019.

The net energy for load is also projected to grow over the same time period. The net energy for load is projected to be 41,995 gigawatt-hours ("GWh") in 2018 and 43,013 GWh in 2019, respectively, which is a 1.4 percent growth rate. The growth in demand and energy is primarily a result of increasing customer growth and improving economic conditions in Florida following the past recession. Exhibit No. ___ (BMHB-4) is a table including the projected net energy for load growth on DEF's system.

More information regarding the demand and energy forecasts, and the methodology used to develop them, is included in the Need Determination Study in Exhibit No. ___ (BMHB-1) and in Chapter 2 of the Company's TYSP, which is Exhibit No. ____ (BMHB-2) to my direct testimony.

Q. Is load growth the only factor driving the Company's reliability needs commencing in the summer of 2018?

A. No. Generation facility retirements also contribute to the Company's reliability needs in the summer of 2018. In February 2013, the Company decided to retire Crystal River Unit 3 ("CR3"), its nuclear power plant at the CREC. CR3 provided DEF's system with approximately 790 MW in summer capacity, after allowing for joint owner shares in the plant capacity, which was no longer available to meet DEF's future capacity needs when DEF decided to retire the plant. This retirement decision was first reflected in the Company's 2013 TYSP and its impact is included in DEF's IRP process in the 2014 TYSP.

In addition to the CR3 retirement, the Company also plans to retire its oldest coal-fired generation plants, Crystal River Unit 1 ("CR1") and Crystal River Unit 2 ("CR2"), also located at the CREC. CR1 and CR2 are 1960's vintage coal-fired generation with a combined summer capacity of about 740 MW. Current air permits allow the Company to continue operation of CR1 and CR2 through 2020, if CR1 and

CR2 meet all applicable environmental regulations. The United States Environmental Protection Agency ("EPA") and the Florida Department of Environmental Protection ("FDEP"), however, established new air emission standards and limits that affect the continued operation of CR1 and CR2 through 2020 without substantial investment in new environmental compliance equipment and measures for CR1 and CR2. As a result, the Company evaluated the retirement of CR1 and CR2 prior to 2020.

Q. What EPA and FDEP regulations impact the Company's ability to continue to operate CR1 and CR2 through 2020?

A. Most recently, the EPA issued its final rule replacing the Clean Air Mercury Rule ("CAMR"), which was vacated by the United States Court of Appeals for the District of Columbia. CAMR was part of a series of EPA regulations addressing the emissions from fossil-fuel generation plants that include the Clean Air Interstate Rule ("CAIR") and the Clean Air Visibility Rule ("CAVR"). These regulations led DEF to develop an Integrated Clean Air Compliance Plan that was approved by the Commission in Order No. PSC-07-0922-FOF-EI. That Plan included the installation of emission control facilities and equipment at the Company's other coal-fired generation plants, Crystal River Units 4 ("CR4") and 5 ("CR5"), at the CREC, and the planned retirement of CR1 and CR2 in 2020.

As a result of CAVR, continued operation of CR1 and CR2 is subject to Best Available Retrofit Technology ("BART") and Reasonable Further Progress ("Beyond BART") requirements. These requirements fully go into effect in 2018, and to comply with them, the Company would have to install expensive Flue Gas

Desulfurization ("FGD") and Selective Catalytic Reduction ("SCR") equipment on CR1 and CR2 by 2018 or cease operation in 2020.

Early in 2012, the EPA replaced the vacated CAMR with the Mercury and Air Toxics Standards ("MATS") rule. The MATS rule imposes emission limits for mercury and other metals and acid gases from coal-fired and oil-fired electric utility generating units. Compliance with MATS is required within three years, or by April 2015, unless extended under certain, limited circumstances one year by the FDEP. DEF developed a plan for limited continued operation of CR1 and CR2 in compliance with MATS. This operation requires some modest upgrades to the units. The one-year MATS compliance extension was granted for CR1 and CR2 by FDEP based on the need for time to complete these upgrades. FDEP also recognized that continued operation of CR1 and CR2 deferred or resolved significant grid reliability issues identified in the Florida Reliability Coordinating Council ("FRCC") MATS study completed in 2013.

Q. What did the Company decide to do with CR1 and CR2 based on its evaluation of these environmental regulations?

A. The Company determined that there was a cost-effective way to comply with the MATS and CAVR requirements and continue to operate CR1 and CR2 in the near term until replacement generation could be built or acquired and associated transmission projects, if needed, could be constructed. Based on the Company's evaluations and coal fuel tests, the Company decided that it could continue to operate CR1 and CR2 until mid-2018 by burning alternate coals and installing less expensive pollution controls than the FCD and SCR equipment at CR1 and CR2. The continued operation of CR1 and CR2 through mid-2018 resolved the near term grid reliability issues that the FRCC MATS study identified. As the MATS Study further recognized, the addition of a new combined cycle generation plant in the Citrus County vicinity in 2018, as first provided for in the Company's 2013 TYSP, fully resolved the grid reliability issues after 2018. Accordingly, DEF petitioned the Commission to modify its Integrated Clean Air Compliance Plan to incorporate these new environmental compliance activities for CR1 and CR2 and the Commission approved this modification in Order No. PSC-14-0173-PAA-EI (consummating Order No. PSC-14-0218-CO-EI issued May 9, 2014). The Company plans to retire CR1 and CR2 in 2018, when the Citrus County Combined Cycle Power Plant achieves commercial operation.

Q. Are these the only generation facility retirements that impact the Company's reliability needs by 2018?

A. No. The Company plans to retire its three 1950's vintage oil- and gas-fired, steam generation plants at the Company's Suwannee power plant site by 2016. These smaller units provide a net 129 MW summer capacity to DEF's system. In addition, the Company plans to retire several of its oldest combustion turbine peaking units on its system between 2014 and 2016. All of these peaking units were built in the 1960's and early 1970's; they are some of the least efficient units on DEF's system; and they are increasingly more costly to maintain. They account for a total of 133 MW of summer capacity on DEF's system. All of these additional retirements are identified in the Company's current 2014 TYSP attached as Exhibit No. ___ (BMHB-2) to my direct testimony.

It is the net impact of the Company's load growth and generation facility retirements that drive the need for additional generation on DEF's system by 2018 to meet the Company's reliability needs. DEF will satisfy part of these reliability needs by 2016 with the addition of its Suwannee Simple Cycle and Hines Chillers Power Uprate projects. These projects are described in DEF's separate petition to the Commission to determine the cost-effective generation alternative to meet DEF's reliability need prior to 2017. DEF will satisfy its additional reliability needs by building its NPGU in its updated Base Generation Plan, the Citrus County Combined Cycle Power Plant.

Q. When did DEF update its Base Generation Plan?

A. The Company continually reviews its resource plan as part of its on-going IRP process. This process did not end when the Company filed its 2013 TYSP with the Commission. That Base Generation Expansion Plan included the CR3 retirement and the CR1 and CR2 retirements, although at that time the CR1 and CR2 retirements were projected to occur in 2016. The 2013 Base Generation Expansion Plan also included the Suwannee unit retirements in 2018, and the oldest combustion turbine unit retirements, with the projected need for additional capacity between 2013 and 2022. To meet this additional capacity need, DEF at that time planned additional power purchases and the construction of smaller combined cycle power plants than the Citrus County Combined Cycle Power Plant in 2018 and 2020, subject to further

Company analysis of these options and the most cost-effective alternatives to meet the Company's additional generation capacity needs. Indeed, we always make clear in our TYSPs that fulfillment of the Base Generation Expansion Plan depends on, among other factors, changes in projected load growth, legislative and regulatory changes, permitting and licensing requirements, and cost and schedule changes.

After filing its 2013 TYSP with the Commission, the Company obtained additional clarity around the environmental requirements affecting CR1 and CR2 that led the Company to decide to pursue the modifications to its Integrated Clean Air Compliance Plan that I described above to continue to operate CR1 and CR2 until mid-2018. Additionally, as reflected in the 2013 Settlement Agreement, the Company decided to evaluate potential generation facility acquisitions and self-build generation options in addition to potential power purchases to meet the Company's near term needs for additional capacity. At the same time, the Company still planned to build a combined cycle generation plant in 2018, albeit a larger plant to meet load forecast changes and the modifications to the plan prior to 2018, subject to the determination that this was the most cost-effective alternative in the 2018 RFP in accordance with the Commission's Bid Rule.

All of these changes were taken into account in the Company's recently completed 2018 RFP and are reflected in the Company's current 2014 TYSP. The Base Generation Plan now includes the Citrus County Combined Cycle Power Plant as the NPGU.

Q. Did DEF take into account other, potential generation supply resources before selecting the Citrus County Combined Cycle Power Plant as the Next Planned Generating Unit?

A. Yes. DEF's plan takes into account its future supply of firm capacity from purchased power contracts, as well as its own existing and committed generating units that will be in service during the study period. DEF also examined alternative generation expansion scenarios when it identified the need for additional generation capacity in 2018 in its IRP process. Supply-side resources were screened to identify the most cost-effective generation resources, beginning with a wide range of industry options. DEF pre-screened the options that did not warrant more detailed cost-effectiveness analysis based on industry information and experience with the generation options and DEF's own information and experience with them. The screening criteria included costs, fuel sources and availability, technological maturity, generation capacity efficiency and availability, and overall resource feasibility within the Company's system.

Generation alternatives that passed the initial screening were considered viable generation capacity alternatives and were included in the next step of the IRP process. That step involved an economic evaluation of the generation alternatives in a computer model called Strategist. Strategist is an electric utility industry standard resource optimization program. Strategist models DEF's system and determines the combination or combinations of future resource additions that meet system reliability criteria while satisfying system constraints at the most cost-effective total production cost for DEF's system. The primary output of Strategist is the Cumulative Present Value Revenue Requirements ("CPVRR").

The most cost-effective supply-side resource or combinations of resources are evaluated and the various generation plans are ranked by system revenue requirements, or the CPVRR results. Strategist considers many tens or hundreds of thousands of resource combinations. Each of these resource combinations is ranked based on cost performance over both the planning period (20 years) and the study period which includes end effects. After using Strategist to identify the lowest cost plan candidates, DEF uses the Planning and Risk module of the Energy Portfolio Manager ("EPM") software to further evaluate the production cost results. EPM is a detailed production cost model which models system behavior at an hourly level and allows for the input of a greater detail of operating constraints. DEF combines the production cost results of EPM with the fixed cost outputs from Strategist to create its final rankings. Generally, the generation plan with the lowest CPVRR over the study period is chosen as the Base Generation Plan. In this case, the updated Base Generation Plan includes the Citrus County Combined Cycle Power Plant as the NPGU.

Q. Did DEF evaluate demand-side programs to determine if they could replace or mitigate the need for the Next Planned Generating Unit in the Company's IRP process?

A. Yes. In a general manner, demand-side resources are evaluated in much the same manner as supply-side resources. Industry and Company information on potential demand-side resources are collected for evaluation. These potential demand-side resources are screened to eliminate resources that are in research and development and not commercially or technically viable at this time. Potential demand-side resources that are already available or otherwise in place, for example, through building code changes, and those that are not applicable to DEF customers are also eliminated in the screening process. Strategist is then up-dated with the cost and load impact parameters for the potential demand-side resources that survive the screening process. The Strategist model screens these demand-side resources on an individual basis against supply-side generation avoided units to determine the benefit or detriment to the DEF system from adding the demand-side resource to DEF's system. Strategist will calculate the benefits and costs for each demand-side resource and produce reports that provide the ratios for the Rate Impact Measure ("RIM"), Total Resource Cost Test ("TRC"), and the Participant Test. Cost-effective demand-side resources are implemented and included in the Strategist model to determine the Integrated Optimal Resource Plan that produces the Base Generation Expansion Plan.

Q. What were the results of your evaluation of demand-side resources as a potential replacement or mitigation for the need for additional generation resources in 2018?

A. There are no demand-side resources reasonably available to DEF to replace or mitigate the need for additional generation capacity in 2018 to meet the Company's reliability needs. DEF included the demand-side resources in its current Demand Side Management ("DSM") Plan, as modified by the Commission in Order No. PSC-11-

0347-PAA-EG, and, as further modified by administrative approval in 2012, in its model runs to determine the Base Generation Plan. These DSM programs extend through the end of this year when new DSM goals for the next ten years will be approved by the Commission in Docket No. 130200-EI and when subsequently DEF will submit proposed DSM programs to meet those goals for Commission approval. The Company assessed the projected cost, performance, viability, and cost-effectiveness of a wide range of dispatchable and non-dispatchable DSM programs and selected the DSM programs as the most cost-effective demand-side resources reasonably available to the Company. They do not replace or offset the need for additional supply-side generation resources in 2018.

Q. Did the Company consider the impact of potential future changes in the DSM program in its IRP process to determine its need for additional generation resources in 2018?

A. Yes. DEF has performed the IRP process evaluations necessary for the Commission's current DSM goals docket and, based on the results of those analyses, there is no reason to conclude that the Company's determination that it needs additional supply-side generation capacity in 2018 to meet its reliability needs will be affected by the outcome of that docket. Over the next ten years the Company's proposed conservation goals are generally lower than the existing set of goals, reflecting less available savings from demand-side resources. All other things being equal, this change causes an increase in DEF's firm winter and summer peak demand and, therefore, further establishes the need for the Citrus County Combined Cycle Power Plant NPGU to meet DEF's reliability need in 2018.

DEF has successfully implemented cost-effective DSM programs for the past thirty years to reduce energy demand and energy consumption and avoid generation. Through 2011, DEF's Commission-approved DSM programs have resulted in over \$1.2 billion in customer energy savings by achieving reductions in energy consumption of more than 5,000 GWh and demand savings of over 1,645 MW, effectively eliminating the need for the Company to build and operate approximately 18 peaking power plants. Substantial reductions in energy consumption and demand, therefore, already have been achieved in the Company's service territory, necessarily resulting in diminishing future energy consumption and demand reductions from more costly future energy efficiency programs and measures. The past success of the Company's DSM programs -- together with increasing gains in energy efficiency by measures implemented by customers themselves, either independently or as a result of other, non-utility incentives, such as building code changes for new customer construction -- means that achieving the next incremental increase in energy efficiency and demand reduction is more difficult and more costly. The Commission recognized this in its 2014 Florida Energy Efficiency and Conservation Act ("FEECA") report to the Florida Legislature, explaining that such changes reduce the amount of incremental energy available to count toward utility savings through utility DSM programs.

For these reasons, DEF expects that its proposed DSM goals for the next ten years will be accepted by the Commission. As a result, the proposed DSM goals will have no impact on the Company's reliability need in 2018. There simply are no DSM measures that can offset the need for additional generation capacity beginning in 2018, certainly not any that can be implemented at a cost effective rate that is acceptable for DEF's customers.

V. NEXT-PLANNED GENERATING UNIT: CITRUS COUNTY COMBINED CYCLE POWER PLANT.

Q. Please explain the Company's Base Generation Expansion Plan.

A. Through the Company's IRP process we developed the Company's Base Generation Expansion Plan. The Plan includes the addition of the Suwannee Simple Cycle project, involving the construction of two new, highly-efficient, combustion turbine units at the existing Suwannee power plant site in 2016, and the Hines Chillers Power Uprate project at the HEC in 2017. The Plan also includes the construction of the Citrus County Combined Cycle Power Plant at the new Citrus County site adjacent to the CREC as the NPGU in 2018. The Citrus County Combined Cycle Power Plant will be a state-of-the-art combined cycle power plant. The Plan also calls for the addition of another combined cycle power plant at an undesignated site in 2021. DEF's present Determination of Need Petition, its separate petition to determine the most cost-effective alternative to meet its capacity needs prior to 2017, and its April 2014 TYSP are all consistent with the Company's IRP process and this Base Generation Expansion Plan.

Q. What impact will the addition of the Citrus County Combined Cycle Power Plant have on DEF's Reserve Margin reliability criterion?

A. As shown in Exhibit No. ___ (BMHB-3), the addition of the Citrus County Combined Cycle Power Plant will increase DEF's summer peak Reserve Margin to about 20.4 percent in 2018 and 23.6 percent in 2019. The Citrus County Combined Cycle Power Plant allows DEF to satisfy its commitment to maintain a minimum 20 percent Reserve Margin by 2018 and beyond 2018.

Q. Are there other considerations in balancing demand- and supply-side resources?

A. Yes. The Company calculates its Reserve Margin based on the relationship between firm load and total generation capacity available to serve that load. Firm load represents firm customer load after all DSM capability is implemented. Dispatchable DSM demand-side resources reduce the peak customer load, when needed. However, based on the Company's prior experience implementing its dispatchable demand-side resources, such resources cannot be used as often or as long as physical generation reserves without eventually affecting customer participation levels in the dispatchable DSM programs. In other words, customers are less willing to accept service under the dispatchable DSM demand-side resource programs for lower rates when interruptions in electric service increase in frequency or duration. For this reason, additional physical reserves are a more reliable power supply than the consent of customers to interruptions in electric service for reduced tariffs resulting from their participation in dispatchable DSM programs. Based on projected load growth, the addition of the Citrus County Combined Cycle Power Plant will increase the Company's share of physical reserves to approximately 60 percent of total summer reserve capacity, including DSM, in the summer of 2018. DEF believes this is an appropriate level of physical reserves because it provides a cost effective balance of the need for physical reserves to respond to reliability needs under adverse load and capacity conditions and the availability of dispatchable load control to respond to short term upsets and peak shaving events.

Q. Why has DEF chosen natural-gas fired, combined cycle generation to install?

A. Our CPVRR economic analyses favor natural-gas fired, combined cycle generation to meet our generation reliability needs. DEF has projected the need for combined cycle generation capacity in its 2013 and 2014 TYSP filings, and natural-gas fired, combined cycle generation has been a competitive generation resource for Florida for many years.

One reason for this is that there are few, large-scale generation capacity technologies available to Florida utilities that can produce power on a base load basis. Increasing environmental emission regulations and permitting requirements have made utility-scale coal-fired, steam generation increasingly costly to build and operate, and difficult to impossible to site and permit in Florida. Barring advances in coal-fired generation emission-control and carbon-capture technologies that are not yet commercially available, there is no reason to believe at this time that an electric utility can obtain a need determination and the necessary permits to build a new coal-fired, steam generation plant in Florida.

Likewise, DEF is no longer pursuing new nuclear power generation in Florida, despite the relative cost-effectiveness of new nuclear generation in a carbon-constrained future regulatory environment and the fuel diversity benefits that nuclear generation provides DEF and the State of Florida. As a result, while DEF continues to regard new nuclear generation as a viable, future base-load generation resource for Florida, the Company's decision to build new nuclear generation in the future depends on, among other factors, future energy needs, nuclear development and construction cost, future carbon regulation, future natural gas prices, and the current and future legislative and regulatory provisions for cost recovery for nuclear development and construction costs.

As a result, natural-gas fired, combined cycle generation is the most economic and qualitatively attractive large-scale generation technology for DEF and the State of Florida at this time and for the foreseeable future. This technology, however, is by no means simply a "default" generation choice. Another reason to choose this generation technology is that improvements in the technology with its wide spread development and use the past two decades have increased its generation efficiency, lowering the cost per unit of fuel for this technology, and making the combined cycle generation technology an even more cost-effective producer of energy. Exhibit No. ___ (BMHB-5), which contains a comparison of the cost efficiency of the combined cycle generation technology compared to other commercially available, utility-scale generation technologies, demonstrates the cost effectiveness of combined cycle generation at high capacity factors in baseload and intermediate service.

Q. Is DEF becoming too dependent on natural gas for its generation?

A. No. Current economics overwhelmingly favor natural gas units, and for good reason. As demonstrated above and in Exhibit No. ____ (BMHB-5), natural gas-fired, combined cycle generation is a highly efficient, cost-effective source of generation capacity. In addition, there are abundant natural gas resources available in the United States and North America. These natural gas resources ensure a long term natural gas supply at economically beneficial prices for electric power generation in this country and, in particular, here in Florida.

Q. Why does the Company believe there is an adequate, long-term supply of natural gas available at economically beneficial prices for the Citrus County Combined Cycle Power Plant?

A. Recent technological improvements in gas drilling, colloquially called "fracking," have led to unconventional shale gas developments that now provide access to gas supplies that simply did not exist as few as ten years ago. Exhibit No. ___ (BMHB-6) shows the location of the unconventional shale gas developments and major gas pipelines in the Southeast United States. As demonstrated in Exhibit No. ___ (BMHB-6), there are several Southeast shale gas plays with abundant shale gas. The widespread employment of gas fracking technology ensures that shale gas plays will provide an abundant supply of natural gas for electric power generation over the thirty five year planning period used to determine the cost-effectiveness of the Citrus County Combined Cycle Power Plant. The availability of these gas resources and their impact on the future price of natural gas for future gas power production are explained in more detail by Mr. Delehanty in his direct testimony.

While the focus in production and transportation development has been on shale gas sources, there remains abundant conventional gas resources in commercial development or available for future development in North America. Again, advances in drilling technology and efficiencies have actually expanded the ability to produce gas from these conventional resources. Exhibit No. ___ (BMHB-7) to my direct testimony depicts the recent, current, and future production from both conventional and unconventional North American natural gas resources. While shale gas production is expected to grow at the fastest rate, conventional gas resources are also expected to increase production over the next 25 years. Conventional natural gas production in North America will continue to be a long-term gas supply resource for electric power generation in this country.

DEF plans to access both the conventional and unconventional gas supplies for the Citrus County Combined Cycle Power Plant. DEF has a gas transportation contract for the Citrus County Combined Cycle Power Plant with Sabal Trail. Sabal Trail is building a new, third natural gas pipeline into the State of Florida. Exhibit No. ___ (BMHB-8) is a map showing the location of the Sabal Trail natural gas pipeline. As demonstrated on this map, the Sabal Trail pipeline extends from Transcontinental Pipe Line Company Compressor Station 85 ("Transco Station 85") in Choctaw County, Alabama to a planned gas transportation interconnection hub in Orange County Florida. This hub will provide interconnection between Sabal Trail and the existing FGT and Gulfstream pipeline infrastructure. This will provide access to Sabal Trail supplied gas throughout the State. Transco Station 85 provides Sabal Trail access to the abundant, unconventional shale gas supplies in the Southwestern United States. This can be seen by comparing the location of the Sabal Trail pipeline connection at Transco Station 85 and its other pipeline connections on the map in Exhibit No. ___ (BMHB-8) to the map of the unconventional shale gas plays in Exhibit No. ___ (BMHB-6). Sabal Trail, therefore, can draw from both conventional and unconventional natural on-shore natural gas supplies. When DEF adds the Citrus County Combined Cycle Power Plant to its system and connects that Plant with Sabal Trail DEF adds natural gas fuel supply diversity to its system. The fuel supply plan for the Citrus County Combined Cycle Power Plant is further explained by Mr. Patton in his direct testimony.

Q. Will DEF have access to other natural gas pipelines for gas supply to the Citrus County Combined Cycle Power Plant?

A. Yes. DEF will also be able to access the existing Florida Gas Transmission Company ("FGT") pipeline for the Citrus County Combined Cycle Power Plant. The location of the FGT pipeline and the Gulfstream pipeline, the other existing natural gas pipeline into the State of Florida, in relation to the Sabal Trail pipeline is also depicted in Exhibit No. ___ (BMHB-8) to my direct testimony. This connection is also explained in more detail by Mr. Patton in his direct testimony in this proceeding. This ability to access the FGT pipeline provides DEF additional fuel supply diversity by making more conventional gas supplies in the Gulf of Mexico and on the coast available to the Company for the Citrus County Combined Cycle Power Plant.

Q. Does natural gas supply diversity provide sufficient fuel diversity?

A. Yes. The abundant supply of unconventional natural gas resources is a significant recent development that provides electric utilities like DEF with natural gas supply diversity to achieve one of the primary objectives of fuel diversity, namely, ensuring that fuel is readily available at a cost-effective price. Access to both these unconventional natural gas resources and conventional natural gas resources also achieves the second primary objective of fuel diversity, that is, ensuring a reliable fuel supply in the event of gas supply interruptions. The natural gas fuel supply diversity means the Company can still generate electricity economically in the event of such interruptions to one or more of the fuel supply resources available to DEF for the Citrus County Combined Cycle Power Plant. DEF, therefore, has reasonably provided for the benefits of fuel diversity with the construction and operation of the Citrus County Combined Cycle Power Plant on its system.

Also, DEF still has substantial base load coal-fired, steam generation capacity on its system. DEF recently retro-fitted the CR4 and CR5 coal-fired, steam generation facilities to meet existing and future environmental emission regulations. CR4 and CR5, accordingly, will continue to provide over 1,400MW of summer (and winter) base load generation capacity to DEF customers. This coal-fired generation provides DEF additional fuel diversity.

Finally, there simply are no other commercially available, utility-scale generation facility resources that can feasibly be added to DEF's system to meet DEF's generation capacity needs. As I explained above, building new coal-fired generation or nuclear generation capacity in Florida is not feasible at this time given environmental constraints and the existing legislative and regulatory framework. There also is a limited outlook for cost-effective renewable resources to meet DEF's reliability needs.

Q. Why are there limited renewable resources available to meet DEF's reliability needs?

A. Renewable resources such as wind, solar, and bio-mass are not commercially available on a utility-scale for generation capacity at a cost-effective price. DEF has held open a Request for Renewables ("RFR") for renewable generation resources for years and DEF has not received a utility-scale, commercially viable solar or wind proposal that has actually achieved commercial operation. In addition, DEF's 2018 RFP was open to all proposals for additional generation capacity and the only proposals DEF received were for gas-fired generation (with the exception of a small, existing municipal waste renewable generation facility). DEF will continue to solicit renewable projects through its RFR, however, large scale, commercially viable and economic generation capacity renewable projects cannot be reasonably expected at this time.

Q. Are there environmental benefits to adding the Citrus County Combined Cycle Power Plant to DEF's system?

A. Yes. A combined cycle facility fueled by natural gas is the cleanest and most efficient fossil-fueled generation. For example, there are virtually no sulfur dioxide (SO_2) emissions. Nitrogen oxide (NO_x) emissions, with low NO_x burners installed, are approximately one tenth the level of coal-fired, steam generation NOx emissions. These and other environmental benefits from adding the Citrus County Combined Cycle Power Plant to our system are explained in more detail in the testimony of Amy Dierolf in this proceeding.

In addition to providing needed baseload capacity in a cost effective and environmentally responsible manner, during off-peak periods, the more efficient generation of the Citrus County Combined Cycle Power Plant will displace generation from other less efficient and less well controlled sources, reducing DEF's overall portfolio emissions. The proposed Citrus County Combined Cycle Power Plant will provide cleaner air for Florida compared to other alternative, commercially feasible, utility-scale generation technologies. The Citrus County Combined Cycle Power Plant will help the Company comply with current environmental regulations, as well as prepare the Company to meet more stringent regulations that may be enacted in the future.

VI. DEF's 2018 RFP.

Q. Please describe DEF's 2018 RFP.

A. In accordance with the Commission Bid Rule, DEF issued the 2018 RFP on October 8, 2013, soliciting proposals for other generation capacity resources that might prove superior as a supply-side alternative to the Company's Citrus County Combined Cycle Power Plant NPGU. The 2018 RFP is included as an appendix to the Need Study included as Exhibit No. ___ (BMHB-1) to my direct testimony.

In our 2018 RFP, we explained that we had identified the Citrus County Combined Cycle Power Plant as our NPGU, and we invited interested parties to make alternative proposals that offered superior value, based on price and non-price attributes, to the Company's customers. We sought reliable, dispatchable, financially and technically sound capacity and energy proposals to meet DEF's reliability need in 2018. We evaluated all proposals by systematically following a structured, orderly evaluation process, which we identified in the 2018 RFP, along with the criteria by which we evaluated the proposals.

Q. Briefly, what were the results of the RFP?

A. We received six proposals in addition to the Company's self-build proposal for the Citrus County Combined Cycle Power Plant NPGU. Bidders also included five alternatives to their base proposals. None of these proposals met the Company's reliability need for 1,640 MW of summer generation capacity in the year 2018, with a minimum of 820 MW in service no later than May 1, 2018 and the balance of generation capacity in service no later than December 1, 2018. None of the proposals individually met the request for 820 MW in service by May 1, 2018 and in fact, all six proposals combined did not meet the Company's reliability need for generation capacity in 2018. This reliability need was clearly explained to potential bidders in the 2018 RFP.

Because none of these six proposals individually or collectively met DEF's reliability need in 2018, DEF reasonably could have rejected the proposals for failure to comply with the 2018 RFP without further evaluation and selected the self-build proposal for the Citrus County Combined Cycle Power Plant NPGU. DEF decided to continue its evaluation of these six proposals, however, to see if there was any combination of them that, individually or collectively with other, undeveloped generic Company power plants, provided customers a more cost effective supply-side generation alternative to the Citrus County Combined Cycle Power Plant NPGU. These combinations, or resource combination scenarios, were quantitatively and qualitatively evaluated against the Citrus County Combined Cycle Power Plant.

That evaluation, as I describe in more detail below, demonstrated that the Citrus County Combined Cycle Power Plant NPGU is the most cost-effective supply-side generation capacity to meet the Company's reliability need in 2018. The Citrus County Combined Cycle Power Plant is approximately $477 million less expensive than the most realistic least-cost, third-party proposal resource combination scenario. We further performed sensitivity analyses, in which we assumed either a high gas price forecast case or a zero carbon cost ("CO2") price case, and, in all these cases, the Citrus County Combined Cycle Power Plant is the least cost alternative. Our evaluations demonstrate that the selection of the Citrus Country Combined Cycle Power Plant is the right choice for our customers.

Q. Were there any other issues with the 2018 RFP bids besides their failure to meet the Company's reliability needs identified in the 2018 RFP?

A. Yes. There were non-conformance issues or risks associated with the 2018 RFP threshold requirements or technical criteria associated with each of these six 2018 RFP proposals. These are explained in more detail below or in the Need Study.

Despite these issues and risks, DEF also determined that, given the limited number of 2018 RFP bids DEF received, it would consider all bids in the preliminary economic evaluation and detailed evaluations described in the 2018 RFP. These bid non-conformance issues or risks were considered in the Company's qualitative assessment of the non-price attributes of the bid proposals in the detailed evaluations.

Q. Please describe the 2018 RFP.

A. The 2018 RFP has four key components. The first component is the Solicitation Document, which outlined DEF's need for generating capacity, the objectives of the 2018 RFP, the Company's NPGU, DEF's system specific conditions, and a schedule of key dates in the 2018 RFP process. The document also addresses DEF's requirements for the submission of bids, and it described the criteria that DEF would use to compare and evaluate the price and non-price attributes of the proposals, consistent with the requirements of the Commission Bid Rule.

The second key component was the Response Package. The Response Package contained a description of the information bidders were to provide in their proposals. It defined the required organizational structure and contents of any submitted proposal and it contained instructions on how to complete the schedules (or forms) provided to the bidders. The third key component consisted of the Schedules (Microsoft Excel worksheets) that bidders were required to use to provide data, including pricing, to DEF.

The fourth key component was the key Terms and Conditions of a purchased power agreement in the event that a bid proposal was selected as the most cost-effective generation option to meet DEF's reliability need. Also, consistent with the Bid Rule, a copy of DEF's most recent TYSP, the 2013 TYSP, was attached to the 2018 RFP.

Q. Did you open the 2018 RFP up to all potential participants and proposals?

A. Yes, DEF invited all creative, innovative, or inventive responses that met DEF's fundamental requirement for firm supply-side, dispatchable capacity and energy in 2018. DEF, in fact, eliminated the planned minimum capacity requirement in the 2018 RFP at the request of a potential bidder at the 2018 RFP pre-issuance meeting. DEF was, therefore, willing to consider and did consider firm, dispatchable generation capacity proposals of any size in combination with other proposals or in resource portfolios with generic Company generation units to meet its generation capacity reliability need in 2018.

Second, to provide bidders more flexibility, we allowed delivery terms for proposals between 15 and 35 years, despite DEF's need for a long-term supply of reliable generation capacity. Third, we allowed potential bidders to submit up to two variations in their bid proposals at no additional cost. Fourth, we allowed potential bidders to provide generation capacity up to sixty days early, before DEF's capacity was needed. Finally, we told the bidders we would allow them to propose a fuel tolling arrangement whereby DEF would be responsible for acquiring fuel for the proposed project.

Q. What was the first step in the 2018 RFP process?

A. The 2018 RFP process started with our announcement that we were going to be issuing an RFP for generating alternatives. We provided public notice of the RFP issuance on September 24, 2013. The public notice was published in newspapers of state and national circulation, and in trade publications and periodicals, consistent with the Bid Rule. These publications were Megawatt Daily, SNL, the Tampa Tribune, the Orlando Sentinel, Energy Biz, and Power Engineering. The notice provided a general description of the Company's NPGU, the name and address of the contact person from whom to request a 2018 RFP package, the Company's 2018 RFP web site address where the 2018 RFP package also could be obtained, and the schedule of critical dates for the 2018 RFP process. A press release was also published and referred to in articles by a number of news services, both in print and on-line, including the Tampa Bay Times, the Wall Street Journal, Power Engineering, Yahoo Finance and others.

Q. When was the 2018 RFP package first available on the 2018 RFP web site.

A. Draft versions of the 2018 RFP Solicitation Document and the Response Package were available on September 24, 2013. Drafts of the 2018 RFP documents were made available to potential applicants so a more informed discussion about the RFP could take place at the 2018 RFP Pre-Issuance meeting.

Q. Was there a contact person for any questions, clarifications, or requests for additional information about the 2018 RFP?

A. Yes. I was the DEF 2018 RFP contact and my contact information was provided to potential bidders in the draft 2018 RFP solicitation document and on the 2018 RFP website. DEF also retained Alan Taylor with Sedway Consulting, Inc. as an independent monitor/evaluator ("IM/E") for the 2018 RFP. His contact information was also provided to potential bidders in the draft 2018 RFP solicitation document and on the 2018 RFP website. Potential bidders were asked in the 2018 RFP solicitation to contact both of us with any questions or comments regarding the 2018 RFP.

Q. What was the role of an Independent Monitor and Evaluator for the 2018 RFP?

A. DEF retained an independent monitor to ensure the 2018 RFP process was fair and impartial and that the 2018 RFP solicitation documents were clear, fair, and consistent with the Commission Bid Rule. DEF also retained an independent evaluator to ensure that DEF's evaluation of the proposals received in response to the 2018 RFP was fair and impartial and that the Company's selection of the most cost-effective proposal to meet DEF's reliability need in response to the 2018 RFP was reasonable.

Q. Why was Mr. Taylor retained as the Independent Monitor and Evaluator for the 2018 RFP?

A. Mr. Taylor and his company, Sedway Consulting, have considerable industry expertise and experience with RFPs for supply-side generation. Mr. Taylor and Sedway Consulting have served as the independent monitor and evaluator for utility solicitations for capacity, energy, or both in California, Colorado, Georgia, Iowa, Illinois, Minnesota, North Carolina, South Dakota, and Texas. In addition, Mr. Taylor has provided independent monitor or evaluator services for several RFPs in Florida, including prior RFPs by DEF's predecessors. Mr. Taylor has testified in several Commission need proceedings regarding these RFPs pursuant to the Commission Bid Rule. Mr. Taylor also provided input to the Commission with respect to the development of the Commission's current Bid Rule. More detail on Mr. Taylor's experience as an independent monitor or evaluator and his expertise with respect to utility capacity and energy solicitations is provided by Mr. Taylor in his direct testimony in this proceeding.

Q. What was the Pre-Issuance meeting and when was it held?

A. The Pre-Issuance meeting was held on October 2, 2013 at the Tampa Marriott Westshore located at 1001 North Westshore Boulevard. Potential participants were also allowed to participate in the Pre-Issuance meeting via conference call. The purpose of the Pre-Issuance meeting was to discuss the requirements of the 2018 RFP. The meeting consisted of a presentation that I made covering the objectives of the 2018 RFP, the types of proposals allowed, the 2018 RFP package, the 2018 RFP process, and our requirements for potential bidders. Throughout the presentation, questions were invited, and when asked, answers were provided. All questions and answers were later posted on the 2018 RFP web site. The pre-issuance meeting was recorded by a court reporter and the transcript of the pre-issuance meeting and a copy of the presentation were posted to the 2018 RFP web site for potential bidders.

Q. Did you make any changes to the RFP based on the Pre-Issuance meeting?

A. Yes, we did. As I explained above, we eliminated a minimum generation capacity limit for the proposals in response to the 2018 RFP at the request of a potential bidder during the Pre-issuance meeting. Other clarifications to some of the wording in the 2018 RFP documents were made based on questions that were asked or comments that were expressed by the participants at the Pre-Issuance meeting.

Q. When did DEF actually issue the RFP?

A. The 2018 RFP was issued on October 8, 2013 and it was available for downloading from the 2018 RFP web site. DEF allowed any interested visitor to the site to download the RFP in PDF format. Entities interested in receiving the editable versions of the RFP and the response package were asked to register. DEF did not refuse any requests to register. Downloads of the PDF version of the RFP were not monitored. Twenty-seven (27) different entities registered to participate in the RFP and receive the editable RFP documents.

Q. Did DEF hold a Bidders' Meeting for the 2018 RFP?

A. Yes, a Bidders' Meeting was held on October 18, 2003, also at the Tampa Marriott Westshore on Westshore Boulevard in Tampa, Florida. The purpose of the Bidders' Meeting was to provide interested parties the opportunity to ask questions and seek additional information or clarification about the 2018 RFP documents and solicitation process. Again, potential participants were allowed to attend by conference call. I made a brief presentation similar to the one I made at the Pre-Issuance meeting, summarizing the 2018 RFP process and the 2018 RFP requirements. Bidders were encouraged to submit questions ahead of time, during the presentation, and after the Bidders' Meeting. All questions and the corresponding answers were posted on the 2018 RFP web site, including the additional questions and answers after the Bidders' Meeting. The Bidders' Meeting was also recorded by a court reporter and the transcript of the Meeting and a copy of the presentation were posted to the 2018 RFP web site for potential bidders.

Q. Did DEF receive proposals in response to the 2018 RFP?

A. Yes. We received six proposals with five variations from third-party bidders on December 9, 2013. The Company's self-build team also submitted a proposal for the Citrus County Combined Cycle Power Plant NPGU on the same date.

Q. What kinds of proposals did you receive?

A. All but one of the bidder proposals were Existing Unit Proposals. There was one bidder New Unit proposal and the self-build team proposal for the Citrus County

Combined Cycle Power Plant. The proposals varied in length, but none of them equaled the expected service life of the Citrus County Combined Cycle Power Plant NPGU of 35 years, which was the study period in the RFP evaluation process. All but one of the proposals would be fueled primarily with natural gas and the other proposal was a small, existing resource recovery facility. The start date for all but one of the proposals was at least by May 1, 2018 with some before that date. A summary of the bidder proposals including a list of the names of the bidders and a description of the size and type of generation in the proposal can be found in a confidential appendix to the Need Study.

VII. THE 2018 RFP EVALUATION PROCESS.

Q. Did DEF describe the evaluation process it was going to use in the 2018 RFP solicitation documents?

A. Yes. The 2018 RFP solicitation document described in detail the evaluation process we planned to use in the evaluation of the proposals in response to the 2018 RFP.

Q. Please briefly describe the evaluation process.

A. The process, of course, is described in detail in the 2018 RFP solicitation document itself, but it is shown in flowchart form in Exhibit No. ___ (BMHB-9) to my direct testimony. This is the same flowchart that was included in the 2018 RFP solicitation document.

Briefly, the first step in the RFP evaluation process was screening for Threshold Requirements. In this step, the proposals were reviewed to ensure they met the basic RFP information requirements. The Threshold Requirements were provided in a table in the 2018 RFP solicitation document so that the potential bidders could check to ensure their proposals fulfilled these requirements. Proposals that did not meet the Threshold Requirements were subject to elimination from further evaluation.

The next step was the preliminary economic screening and screening for compliance with the 2018 RFP Minimum Technical Requirements. The purpose of the preliminary economic screening was to narrow the number of proposals for the more detailed evaluation analyses by eliminating any proposals that were much higher in cost relative to other proposals in the RFP evaluation process. The proposals were screened based on the fixed, variable, and other payments. Proposals that were significantly higher in cost compared to other proposals could be eliminated from further evaluation. The pricing parameters for this preliminary economic screening were made available to potential bidders in a table in the 2018 RFP solicitation document.

In this step DEF also determined if bidders complied with the Minimum Technical Requirements. The Minimum Technical Requirements were also provided to bidders in a table in the 2018 RFP solicitation document. DEF included a description of each of these non-price attributes, as well as the Company's preferences with regard to the attributes. The purpose of the Minimum Technical Requirements was to assess the feasibility and viability of each proposal.

The third step was selection of a short list for the initial and final detailed evaluations in step four of the 2018 RFP evaluation process. In the initial and final detailed evaluations, proposals included on the short list would be compared to DEF's self-build alternative, the Citrus County Combined Cycle Power Plant NPGU. Proposals were subject to more detailed economic and qualitative assessments, and transmission cost impacts would be incorporated into the analyses. Scenario and sensitivity analyses would also be conducted, if deemed appropriate based on the proposals submitted.

The next two steps were selection of a final list of bidders for potential contract negotiation. In the event that the Citrus County Combined Cycle Power Plant was found to be clearly superior to the proposals, a final list would not be selected. We also anticipated an announcement of a final decision after contract negotiations, but that was dependent on the results of the evaluation and would not take place if the Citrus County Combined Cycle Power Plant was found to be a more cost-effective option for customers than the other proposals.

A. THRESHOLD REQUIREMENTS SCREENING.

Q. Was this evaluation process followed?

A. Yes. We began our bid evaluation process with the threshold screening. We evaluated all of the proposals against the Threshold Requirements identified in Figure III-2 of the 2018 RFP solicitation document and shown in Exhibit No. ___ (BMHB-10). As I explained above, the Threshold Requirements represent the minimum requirements that all proposals are required to meet to be evaluated.

Some examples of Threshold Requirements are general requirements, such as the proposal being received on time, the submittal fee being included, and the power being available for delivery by May 1, 2018. Others include operating thresholds, such as operating the project to conform to DEF voltage and frequency control requirements, the agreement by the bidder to coordinate maintenance scheduling, and the bidder demonstrating control of the site. Bidders were also required to agree to key terms and conditions of any potential contract or propose revised terms and conditions for DEF's review and possible acceptance. The threshold screening provided a "sanity check" of the proposals by ensuring that DEF had everything it asked for and needed to perform its evaluation analyses.

Q. Were the key terms and conditions for any contract with a potential bidder?

A. The 2018 RFP solicitation document included a set of terms and conditions for a potential power purchase agreement that were critical to DEF in Attachment A to the 2018 RFP solicitation document. Bidders were not required to agree to all the terms, but were instructed to mark the terms and conditions for any changes that they would like to make. We would then evaluate the proposals based on the extent to which the proposed deal was contingent on changing the key terms and conditions. This would also provide a starting point for contract negotiation if a bidder were selected to the final list. The terms and conditions are too numerous to describe in my testimony but they cover subjects one would customarily expect to see addressed in a power purchase agreement, and, as I mentioned, they were provided to the bidders as an integral part of the 2018 RFP solicitation document.

Q. How did you evaluate the contractual terms offered for each proposal?

A. In the 2018 RFP solicitation document, DEF reserved the right to consider any unique flexibility provisions offered by a bidder. Examples typically include contract options such as buyout provisions, or options to extend the contract, among others. In this RFP, alternate contract structures were offered as variations to base bids and included options to acquire certain units and varying contract lengths. DEF evaluated these as part of the economic screening. Evaluation of any changes to the proposed terms and conditions was deferred until conclusion of the economic screening.

Q. What were the results of the threshold screening?

A. None of the proposals initially passed the Threshold Requirements screening process without any deficiencies. All of the proposals required at least some clarification. DEF explained in the 2018 RFP solicitation document that, at its discretion, DEF would work with the bidders to clarify their proposals if they did not pass the threshold screening based on DEF's initial review. We, in fact, went back to the bidders with questions in an effort to help them resolve the deficiencies in their proposals and to make sure we had everything we needed to conduct a thorough evaluation of the bids. Despite some continuing, existing and potential non-conformance issues with certain bidder proposals, we did not eliminate any proposal for failure to fully conform to the Threshold Requirements. The bidders attempted to provide additional clarification or information in response to DEF's questions. DEF decided to address the existing and potential non-conformance issues in the

Company's qualitative assessment of the risks associated with the bidder proposals in the consideration of the non-price attributes of the proposals.

Q. Was this approach acceptable to the independent monitor and evaluator?

A. Yes. Before we made this decision we discussed it with Mr. Taylor. Mr. Taylor agreed that this was a fair approach to the evaluation process even though DEF had the right under the 2018 RFP solicitation document to disqualify the non-conforming proposals from further evaluation.

B. INITIAL ECONOMIC SCREENING ANALYSIS.

Q. What did you do next in the 2018 RFP evaluation process?

A. We performed our initial economic screening analysis. The screening analysis compared the proposals to each other in terms of $/kW-year, based on the total prices proposed by the bidders and an assumed capacity factor. As I explained above, the purpose of the initial economic screening was to get a perspective of the relative economics of the proposals compared to each other and to potentially eliminate proposals that were way out of line in terms of cost to the other proposals.

Q. What capacity factor did you assume for your initial economic screening analysis?

A. We assumed a capacity factor of 70 percent. This capacity factor was assumed because this was the expected capacity factor for the Citrus County Combined Cycle Power Plant.

Q. What was the result of your analysis?

A. The evaluated costs of all the proposals were within a reasonable range of each other. None of the proposals were so far out of line compared to the other proposals that they were eliminated from further analysis.

C. TECHNICAL EVALUATION.

Q. What was the next step in your evaluation of the proposals received in response to the 2018 RFP?

A. The next step was the Technical Evaluation. In this evaluation we assessed the non-price attributes of the proposals by evaluating the quality of the proposals from a technical perspective. We used the Technical Evaluation to help us get to a potential Short List of proposals for further, more detailed economic and qualitative evaluation by ensuring that all the proposals that went to the potential Short List were technically viable. The Technical Evaluation addressed the Minimum Technical Requirements, which were provided in the 2018 RFP solicitation document and are shown in Exhibit No. ___ (BMHB-11) to my direct testimony.

The Minimum Technical Requirements were the necessary technical elements of a proposal. They were the components, or characteristics, the proposals had to have to move forward in the evaluation process. The Minimum Technical Requirements fell into five categories: Environmental; Engineering and Design; Fuel Supply and Transportation Plan; Project Financial Viability; and Project Management Plan. The Minimum Technical Requirements are the most important non-price attributes of generation supply alternatives to DEF. Failure to meet one of the Minimum

Technical Requirements was grounds for disqualification of the proposal from further consideration in the evaluation process.

Q. Can you explain why the Minimum Technical Requirements are important to DEF?

A. Yes. I will start with the environmental requirements. The two requirements in the environmental category, that a preliminary environmental analysis had been performed and that a reasonable schedule for securing permits was presented to DEF, applied only to New Unit Proposals. The purpose of these requirements was to ensure that, to the greatest extent possible, the bidder for the proposed project could obtain the necessary environmental permits. We assessed the bidder's plan to obtain the necessary land use and environmental permits, including a water supply, for the proposed project, based on our extensive experience with obtaining permits for similar projects. This requirement was important to DEF's determination that the bidder could bring the proposed unit on-line on time.

There were also two requirements in the engineering and design category. The purpose of these requirements was to determine if the technology for the New Unit and Existing Unit Proposals was viable from an engineering and operations perspective. The bidders had to provide an operation and maintenance plan indicating the project would be operated and maintained in a manner that satisfied the bidders' contractual commitments. The bidders also had to demonstrate the project technology would be able to achieve its operating targets. For example, we considered the guarantee the bidder offered for the availability of the unit; that is, what percentage of time the bidder would guarantee that the unit would be available if we called on it. Specifically we did this by ranking the bidders based on the equivalent forced outage rate ("EFOR") they offered to guarantee.

We also evaluated each proposal to determine the operational criteria for the proposed unit, including, among others: Minimum load; Start time; Ramp rate; Maximum starts per year; Minimum run-time constraint; Minimum down-time constraint; and Annual operating hours limit. In general, these attributes measure the flexibility of the proposed unit to operate in ways that respond to changes in demand. We accordingly evaluated the proposed units with respect to how long it would take to get the proposed unit started, how long it would take to get the unit up to the desired output level, the number of times in a year the unit could be started and stopped, the minimum amount of time the unit would have to run once it was started, the amount of time the unit had to be off-line once it was shut down, and the number of hours in a year the unit could operate.

Q. What about fuel supply and transportation, why was that a Minimum Technical Requirement?

A. Bidders of New Unit and Existing Unit Proposals had to provide a preliminary fuel supply plan that described the bidder's plan for securing fuel supply and transportation for delivery to the project. Fuel supply and transportation, of course, are absolutely essential for any new or existing generation unit and a key cost factor in any economic analysis. We evaluated the fuel supply and transportation plans in the proposals based on, among other factors, the location of the plant; whether the plant was connected through a local distribution company ("LDC"); whether backup fuel was available; and, if so, how much backup fuel storage was available.

Alternatively, bidders had the option to propose a fuel tolling arrangement whereby DEF would be responsible for acquiring fuel for the Proposal unit. All bidders with the exception of the municipal waste proposal opted for the fuel tolling arrangement. Each of the natural gas fired bid proposals provided information on existing or expiring gas transportation contracts and/or gas supply infrastructure. This information was used in the evaluation of the proposals.

Q. What was the purpose of the financial viability Minimum Technical Requirement?

A. The purpose of the project financial viability Minimum Technical Requirement was to ensure the bidder had the financial backing to construct and/or operate the project through the term of the proposal. For New Unit Proposals, evidence had to be provided that demonstrated the project would be financially viable. All proposals had to demonstrate that the bidder would have sufficient credit standing and financial resources to satisfy its contractual commitments. We focused on the bidder's financial capability and credit. If the bidder was proposing to obtain project financing for its proposal, we would focus on the financial viability of the proposal. If the bidder indicated it would be providing equity to the project or would be self-financing the project, we would also assess the bidder's ability to provide the required equity or financing.

Q. What was the purpose of the final Minimum Technical Requirement?

A. The final component for the Minimum Technical Requirements applied to New Unit Proposals only. Bidders of New Unit Proposals had to submit a construction management plan to show that the project could be built in time to serve DEF's reliability need. We evaluated the likelihood of the project coming on line on time by evaluating the developer's planned permitting, licensing, and construction milestone schedules based on our extensive experience with developing and constructing similar projects. We also considered the bidder's experience in successfully developing and operating a project of the magnitude proposed.

Q. How were proposals evaluated on the Minimum Technical Requirements?

A. Each proposal was evaluated on each requirement on a "Pass/Fail" or "Go" / "No Go" basis. As discussed above and in the 2018 RFP solicitation document, failure to demonstrate conformance with the Minimum Technical Requirements was grounds for disqualification. Failing to meet a Minimum Technical Requirement should result in the elimination of a proposal from further consideration in the evaluation process because it doesn't meet a minimum standard for a good project. That is, a good project, in DEF's view, is one where there is a high probability that the necessary permits, approvals, financing, and other factors required to build and/or operate the project can be obtained or implemented in time to serve the reliability needs of DEF's customers and continue to serve them over the term of the proposed contract.

For most of the Minimum Technical Requirements, the proposals were reviewed to see if they had the required documents, schedules, or plans. For example, the project management plan required the bidders to provide a critical path diagram and schedule for the project that specified the items on the critical path and demonstrated that the project would achieve commercial operation by May 1, 2018. For requirements such as this, they either provided the information (and it was judged as acceptable), in which case they would pass; or they didn't provide the information (or it was deemed unacceptable), in which case they would fail. The evaluation teams used their years of knowledge and technical expertise to determine if the information provided was valid.

Q. Who evaluated the Minimum Technical Requirements?

A. We established separate teams staffed with personnel with expertise in the areas of development and construction, engineering operations, environmental, financial viability, fuel, key terms and conditions, and transmission to review the proposals. Each of the teams received the executive summaries of the proposals and only those portions of the proposals that dealt with its area of expertise. Only the economic evaluation team had access to the pricing proposals, since the other technical evaluators did not need to know the pricing proposals to perform the evaluation of the proposals on their technical merits. Thus, the technical evaluations were performed blind to the economics of the proposals. This was done to make the Technical Evaluation as impartial as possible.

Q. Did all of the proposals pass the Minimum Technical Requirements evaluation?

A. The Minimum Technical Requirements evaluation uncovered some issues that needed further clarification from all of the bidders, which they attempted to provide, although the clarifications did not resolve all the issues identified. Because DEF had a limited number of bidder proposals to evaluate, DEF elected not to disqualify any proposal from further evaluation, and to consider the remaining issues, as necessary, in any final evaluation of the proposals. If the further economic analysis in the RFP evaluation process eliminated the proposals with these issues from further consideration, there was no need to resolve these issues. If not, then, DEF could also seek to resolve them later in the evaluation process through negotiations with the bidders.

Q. Was this approach also acceptable to the independent monitor and evaluator?

A. Yes. Mr. Taylor participated in this evaluation and the communications with the bidders for further clarifications of their proposals and information in connection with the Minimum Technical Requirements evaluation. Mr. Taylor was aware of the issues that arose during this evaluation and the lack of complete clarity regarding the unresolved issues after the additional information or clarification was provided by the bidders. He agreed, however, with the Company's approach to table these issues until DEF had completed further analysis of the bid proposals.

Q. Were you then ready to announce your Short List?

A. No, as I explained above, DEF needed further clarification of some of the information provided by the bidders or additional information with respect to certain issues that were not resolved in the proposals and by prior clarifications or information from the bidders. DEF realized, however, that there were only twelve alternative proposals. Although there still were non-conformance issues or risks associated with the 2018 RFP Threshold Requirements or Minimum Technical Requirements that the RFP evaluation teams had identified, because there were a limited number of bid proposals, DEF decided to consider all bid proposals in the further economic analysis in the 2018 RFP evaluation process. As a result, there was no Short List. DEF simply elected to continue its evaluation of all bid proposals subject to all the requirements of the 2018 RFP.

Q. Did you notify the bidders of this decision?

A. Yes. All bidders were contacted by DEF in writing on March 3, 2014 for further clarification or information about their bid proposals to assist DEF in its evaluation. In that same letter, DEF informed the bidders that, because of the limited number of proposals DEF received in response to the 2018 RFP, DEF was continuing to evaluate all proposals utilizing all steps of the RFP process as may be necessary in its evaluation of their proposals.

D. INITIAL DETAILED EVALUATION.

Q. What was the next step in your evaluation of the bid proposals in response to the 2018 RFP?

A. DEF proceeded with its Initial Detailed Evaluation. In this step, the bid proposals were compared to the Citrus County Combined Cycle Power Plant NPGU. In order to prepare for detailed production cost modeling DEF created a set of portfolios in which proposals were combined with each other and/or with the generic units to provide adequate resources to meet the 2018 need. These portfolios were then analyzed to determine the CPVRR of that resource plan.

The analyses were performed for a study period of thirty-five years to capture all of the costs associated with each bidder proposal resource plan. DEF chose thirty-five years for the study period in the evaluation because this period coincided with the service life of the Citrus County Combined Cycle Power Plant NPGU. A resource plan incorporating a bidder proposal had to extend for 35 years to replace the Company's base generation resource plan including the Citrus County Combined Cycle Power Plant NPGU. The generation supply alternatives that could be selected were generic combustion turbine and combined cycle units.

Q. You mentioned the combination of bid proposals in resource plans. Why were combinations of bid proposals used to develop resource plans in your optimization analyses?

A. As I testified earlier, none of the bidder's proposals to the 2018 RFP satisfied the Company's reliability need for 1,640 MW of generation in 2018. In fact, the collective generation supply capacity of all bidder proposals did not meet the Company's 1,640 MW need. The total generation capacity offered by all bidders in response to the 2018 RFP was 1,328 MW. Additionally, most of the bidders proposed generation terms that did not equal the 35-year expected service life of the Citrus County Combined Cycle Power Plant NPGU and the few that did were not realistic terms for the proposed generation. As a result, DEF could have rejected all the bids without any evaluation because they failed individually and collectively to meet DEF's reliability need in the 2018 RFP.

DEF, nevertheless, decided to evaluate the bidders proposals to see if there was some combination of them, either individually or collectively, with generic resources to meet DEF's reliability need that was superior to the Citrus County Combined Cycle Power Plant NPGU. We, therefore, looked for reasonable resource combination scenarios to evaluate as resource plans for the bidder proposals. These scenarios included a range of resource plan scenarios that included all bidder proposals and generic combustion turbines to scenarios with less than all or single bidder proposals and either generic combustion turbines or combined cycle units. In all these bidder proposal resource plan scenarios some combination of generic combustion turbines or combined cycle units were needed both to meet the reliability need commencing in 2018 and to "backfill" the bidder proposed generation when it went off line before the end of the expected service life of the Citrus County Combined Cycle Power Plant NPGU. Exhibit No. ___ (BMHB-12) includes a description of the bidder proposal resource scenarios that were evaluated in the Company's Initial Detailed Evaluation.

Q. Please explain the optimization analyses you performed for the Initial Detailed Evaluation of the 2018 RFP bidder proposals.

A. While the economic screening analysis compared the proposals to each other based simply on the cost of the proposals in isolation, the detailed analyses assessed the impact of each proposal resource plan on total system costs and compared those costs to the costs of a Base Case optimal resource plan. The impact on total system costs is important because it shows the net impact on the customer of choosing an alternative, including both the project cost and the impact the alternative would have on system operating costs, for example, fuel and the variable O&M of the other units on DEF's system. DEF created tables of fixed costs including capacity payments, capital requirements for generation and transmission, fixed O&M and fixed gas transportation rates based on the information provided by the bidders, transmission and fuels evaluations, and generic unit information. This data was combined with the results of detailed production cost runs using EPM to establish a total CPVRR for each portfolio.

Q. What was in the Base Case optimal resource plan?

A. The Base Case was the Company's optimal resource plan, which included the Citrus County Combined Cycle Power Plant NPGU. As I testified above, the Citrus County Combined Cycle Power Plant was identified in the Company's IRP process as the NPGU or the optimal self-build generation that met DEF's reliability need in 2018. The 2018 RFP evaluation process determined if there was any alternative among the bidder proposals that provided a lower overall CPVRR, while meeting DEF's technical and reliability criteria, than the Citrus County Combined Cycle Power Plant NPGU. To this end, all the bidder proposal resource plan alternative scenarios were compared to the NPGU in the Company's Base Case.

Q. **Where do you get the assumptions for generic unit costs and operating characteristics?**

A. DEF engages in an annual process of updating projected costs for generic units. DEF hires an industry recognized power plant engineering and construction firm, in this case, Burns and McDonnell, to produce costs for the construction and operation of an array of generation technologies and configurations. DEF subject matter experts then review the data and may make adjustments to reflect specific areas of knowledge including benchmarking against recent projects and operating cost data from the Duke Energy fleet. This data includes both conventional generation and renewable generation and forms the basis for the technology comparisons shown in Exhibit No. ___ (BMHB-5).

For the screening of alternatives, the data are generic in nature and thus not site specific. The costs and operation parameters are adjusted to reflect installation in the southeastern United States. The operating characteristics are based on state-of-the-art designs, and for most technologies, the performance and costs are based on a specific size unit.

Q. How does the generic data compare to the costs for the Citrus County Combined Cycle Power Plant?

A. The generic data are reasonable estimates of the cost and performance characteristics of the technologies based on the best available, generic, utility-industry cost information. DEF uses this generic data for the cost and performance characteristics of the combustion turbine and combined cycle generation technologies in its IRP process each year, including the preparation of the Company's 2013 and 2014 TYSPs. The generic data for these generation technologies are planning estimates, however, and they are not meant to be "budget quality" estimates for the actual construction of plants containing these generation technologies. In general, they are conservative estimates. In other words, the generic unit costs are higher, and the performance of the generic unit is less efficient, than the costs and performance characteristics based on actual construction contract costs for a specific site and manufacturer costs and specifications for a specific plant.

Q. Did you make any adjustments to the generic unit data in the 2018 RFP evaluation?

A. Yes. We made two adjustments to the generic unit performance characteristics. First, we assumed that the generic combined cycle power plants that were added to the bidder resource plans to meet the 1,640 MW reliability need in 2018 were equally as efficient as the technology for the Citrus County Combined Cycle Power Plant NPGU planned for 2018. As a result, we assigned the same performance characteristics and operation costs to these generic combined cycle power plant units that are in the 2018

RFP for the Citrus County Combined Cycle Power Plant NPGU. Second, we assumed that the future generic combined cycle power plants that must be added to the bidder resource plans as "backfill" units because the bidder proposed generation does not extend for the life of the Citrus County Combined Cycle Power Plant NPGU were marginally more efficient units because of technological advances. In other words, we assumed that the technological advances in the combined cycle technology that we have seen in the past ten years would continue for future combined cycle units. This assumption led to better performance characteristics and lower operating costs for the future generic combined cycle power plants than the Citrus County Combined Cycle Power Plant NPGU. Both of these adjustments favored the bidder proposal resource plans.

Q. Please explain what production cost models DEF used and what they do.

A. DEF uses two different costing models in combination along with spreadsheet calculations of certain cost elements to determine total production cost and CPVRR values for various resource alternatives. Our two primary modeling tools are Strategist and EPM. As I explained above, Strategist is a utility system, resource optimization model. We use Strategist to develop optimal resource plans where the objective is to minimize the CPVRR for the DEF generation system, subject to the 20 percent Reserve Margin constraint. In the case of the analysis for the RFP, Strategist was used to develop resource plan alternatives for evaluation to develop the Base Optimal Expansion Plan which included the NPGU and was presented in the 2014 TYSP and used as the basis for the RFP resource plans.

Inputs to the Strategist model include the load and energy forecast and the costs and characteristics, such as heat rates, outage rates, and maintenance requirements, of the existing DEF generating units and DEF purchase power agreements. Costs and operating characteristics of potential future supply-side resources, which could be generating units or purchases, are also included in the model. With these descriptions of the demand and existing and future resources, Strategist develops alternative resource plans to meet the projected future customer requirements using all possible combinations of resources, and it calculates the CPVRR for each combination. The model then sorts each alternative plan from lowest to highest cost.

DEF reviews the lowest cost alternatives for feasibility and then uses these plans along with production performance and cost data as inputs to EPM. EPM is a detailed production cost model which evaluates the fleet dispatch in each hour over the period of the study taking into consideration both costs and projected operating constraints such as unit start times, minimum up and down times, reliability must run requirements, and projections of planned and unplanned outages. Production cost results from EPM were combined with fixed cost calculations from Strategist to confirm the selection of the Base Case Expansion Plan reflected in the 2014 TYSP.

Q. Please explain how the resource plans were identified for the evaluation of bids in the RFP.

A. As discussed previously, because the bids individually and collectively did not meet DEF's 2018 resource need, DEF created portfolios of resources as alternatives to meet the 2018 need. For evaluation purposes DEF used the resource plan identified in the base optimum plan, but removed the NPGU from the portfolios for evaluation of the proposals. DEF then constructed groups of resources using the proposal received and generic units in combination to meet the 2018 need. All the new resources, proposed or generic, were assumed to come in service in 2018. All later resources in the plan, e.g., the 2021 undesignated combined cycle, were kept the same in all resource plans for evaluation. This allowed for an "apples to apples" comparison in which variation in resources later in the plan would not distort the effects of 2018 selections. The only exception to this was the use of the backfill units which were inserted into the plan at the end of the term of each proposal to provide adequate capacity to complete the 35 year evaluation. The portfolios created for evaluation are shown in Exhibit No. ___ (BMHB-12).

Q. How were the models then utilized in the evaluation of bids in the RFP?

A. For each of the proposals, generic units, and backfill units, tables were constructed calculating the fixed costs including capital revenue requirements, fixed O&M, transmission charges, and fixed gas transportation charges. Then, operating data was input to EPM for each resource plan. EPM was used to calculate production cost results for each of the portfolios. The production cost results were then combined with the fixed cost information to get a total CPVRR for each portfolio.

Q. Were any other costs or criteria considered with the optimization analyses in the Initial Detailed Evaluation?

A. Yes. DEF conducted transmission reviews and further technical criteria evaluations. The transmission reviews were screening type studies to provide reasonable estimates of the transmission impacts to integrate the bidder proposals into the DEF system. The technical criteria evaluation was a more detailed assessment of the non-price attributes of the Minimum Technical Requirements that I previously described in my testimony.

Q. Please describe the evaluation of the transmission impacts in the Company's transmission reviews in its Initial Detailed Evaluation.

A. Because no bidder individually or collectively met the Company's 2018 reliability need identified in the 2018 RFP, the resource plan scenarios that reasonably combined individual or combinations of individual bidder proposals with generic units to meet the Company's capacity need were used to form transmission groups for the DEF transmission system in the transmission review studies. The transmission groups were identical to the generation portfolios evaluated. These transmission groups were studied for their overall impact to DEF's system and the Bulk Electric System ("BES").

These transmission service studies were performed consistent with North American Electric Reliability Corporation ("NERC"), FRCC, and DEF standards to ensure that DEF can serve its customers and meet transmission service obligations commencing in and extending beyond 2018. Contingency screening tests were performed at summer and winter peak load conditions, and with various DEF generators and facilities available and economically dispatched, to determine and potentially mitigate reliability criteria violations. Any reliability criteria violations identified on DEF's system in the tests were resolved by acceptable remedial action, including when appropriate, transmission facility upgrades or new transmission facilities. Only those transmission facility upgrades or new facilities necessary to physically transfer the proposed power from the DEF system receipt point to the load center consistent with reliability standards for the conditions commencing in the summer of 2018 were identified in the studies.

Once a list of transmission facility upgrades or new transmission facilities was identified from the studies, the next step in the transmission review was developing cost estimates for the upgrades and new facilities and estimated schedules to complete the transmission upgrades or new facilities. Cost and schedule estimates for the necessary transmission facility upgrades or new transmission facilities were based on DEF and industry standard cost estimations and DEF's experience. DEF relies on the same transmission cost and schedule estimates in its own IRP and transmission planning processes.

Bidders were required to provide as part of their 2018 RFP response package detailed information regarding their proposed power plants to enable DEF to perform the transmission reviews in the transmission group service studies. DEF used the information provided by the bidders in response to the 2018 RFP and in response to DEF requests for more information or clarification in performing its transmission review studies. These transmission group service studies and the results of these studies are discussed in more detail in the testimony of Mr. Ed Scott in this proceeding.

Q. Did any of the bidder proposals require changes to the DEF transmission system?

A. Yes. All of the bidder proposal resource scenarios required transmission facility upgrades or new facilities on DEF's system, the BES, or both. The range of estimated transmission costs for each bidder proposal resource plan scenario is a low of approximately $135 million to a high of approximately $202 million. Again, these results are also explained by Mr. Scott in his direct testimony in this proceeding.

Q. Were the transmission review results included in the Company's Initial Detailed Evaluation?

A. Yes. The addition of the necessary transmission costs for the bidder proposal resource plan scenarios increased the costs of the bidder proposal resource plan scenarios relative to the Citrus County Combined Cycle Power Plant NPGU in every case. The reason for this is that the Citrus County Combined Cycle Power Plant NPGU requires no transmission costs beyond the costs required to connect the Plant with the DEF transmission system and BES. The Citrus County Combined Cycle Power Plant NPGU takes advantage of available Company transmission facilities near the CREC that were built to handle the power generated by the CREC. With the existing and planned retirements of CR1, CR2, and CR3 at the CREC, respectively, these existing transmission facilities are available for additional new generation built in the vicinity of the CREC. There are, therefore, no transmission costs associated with upgrades or new facilities for the DEF transmission system or the BES for the Citrus County Combined Cycle Power Plant NPGU.

None of the bidders to the 2018 RFP proposed generation in the vicinity of the CREC or Citrus County. As a result, none of the generation proposed by the bidders utilizes the available DEF transmission facilities located in this area that were built for CREC generation that has or will be retired by 2018.

Q. Were potential bidders told about the benefits of this location in the 2018 RFP?

A. Yes. DEF explained in the 2018 RFP that the preferred BES location for new DEF capacity was Citrus County. DEF even explained why the Citrus County location was preferred. DEF explained that new generation capacity would replace generation that was being retired in the same area and that there were transmission reliability benefits for DEF and neighboring transmission systems if the new generation capacity was located in that area. DEF further explained that new generation capacity in that area could take advantage of the BES transmission capacity that would become available with the generation capacity retirements in the area. DEF also explained that, if the new generation capacity was not located in the vicinity of Citrus County, DEF expected that significant transmission network upgrades would need to be constructed. Finally, DEF told potential bidders that DEF had located the Citrus County Combined Cycle Power Plant NPGU in Citrus County. Despite this information in the 2018 RFP, none of the bidders submitted proposals for generation capacity in the vicinity of Citrus County.

Q. What did the further technical criteria review involve in the Initial Detailed Evaluation?

A. DEF performed a more detailed qualitative assessment of the operational quality, development and commercial feasibility, and project value technical criteria. This was a more in depth analysis of the information about these criteria provided by the bidders in the 2018 RFP bidder response packages in response to DEF's stated preferences for these criteria in the 2018 RFP solicitation document. The closer the bidders' information was to DEF's preferences for each of these technical criteria the more valuable the bidder proposal to DEF on a qualitative basis.

Q. What were the results of the further technical criteria evaluation?

A. The final technical criteria evaluation of the proposals revealed continuing Threshold Requirement and technical criteria issues. Again, however, given the limited number of bidder proposals in response to the 2018 RFP, we continued to consider these issues as a qualitative risk associated with the proposals in our evaluation.

Our view of the further technical criteria evaluation was influenced by the fact that all of the bidder proposals required generic units to fulfill the reliability need for the Company. As a result, the technical criteria review of a resource plan including some or all of the bidder proposals involved the assessment of unplanned and undeveloped generic units that the Company was not sure the Company could even plan and build in time to meet its reliability need. None of these issues existed with the self-assessment of the Citrus County Combined Cycle Power Plant, which of course, did meet the Company's reliability need and could be built to meet that need.

Consequently, the Citrus County Combined Cycle Power Plant clearly ranked ahead of all the bidder proposals resource scenario alternatives for all the technical criteria. The determinative factor was the need to site, license, obtain environmental permits, engineer, design, and construct the unplanned and undeveloped generic units in the bidder proposal resource scenarios.

Q. What were the results of the Initial Detailed Evaluation?

A. Exhibit No. ___ (BMHB-13) shows the economic results of the optimization analyses in the initial detailed evaluation step in the 2018 RFP evaluation process. The exhibit shows the difference in total system CPVRR associated with each alternative resource plan scenario compared to the Base Case. The analysis shows that resource plan scenario 8 had the lowest future cost for DEF customers of any of the resource plan scenarios including the proposals we received from bidders in response to the 2018 RFP. Scenario 8 was still over $375 million less cost-effective than the resource plan that included the Citrus County Combined Cycle Power Plant NPGU.

Q. Were any further analyses performed by the Company?

A. Yes. Following the Initial Detailed Evaluation the Company also performed the more detailed evaluation in the Final Detailed Evaluation to compare the bidder proposal resource scenarios to DEF's self-build alternative, the Citrus County Combined Cycle Power Plant NPGU. The Final Detailed Evaluation involved a more detailed economic analysis, which included more refined financial analyses, which included the cost of imputed debt by determining the additional equity cost related to potential purchased power arrangements for the bidder proposals.

The results of the production costing analyses were incorporated into the financial analysis of each alternative bidder proposal resource scenario. In addition to the production costs associated with each alternative, that is, the energy charges of each proposal and the Citrus County Combined Cycle Power Plant operating costs, the change in system production costs as a result of each alternative bidder proposal resource scenario, relative to the base case, was also a part of the financial analysis.

The fixed costs of the alternatives, that is, the fixed charges of the bidder proposals and the fixed costs of the generic units in the resource scenarios, and the Citrus County Combined Cycle Power Plant construction costs and fixed O&M costs, were captured in the financial analysis. As mentioned before, each bidder proposal alternative resource scenario was compared to a Base Case that included the Citrus County Combined Cycle Power Plant NPGU.

The transmission construction costs to integrate each of the bidder proposals and the Citrus County Combined Cycle Power Plant into the DEF transmission system were included in the detailed economic analysis. The annual cash flow pattern of the construction costs was based on expenditure patterns typically experienced for transmission lines, transformers, and other necessary transmission facilities. Finally, we also included the cost of imputed debt by determining the additional equity cost related to the purchased power proposal.

Q. Why did you include the cost of imputed debt in your analysis?

A. The cost of imputed debt was applied to proposals to assure that the total costs of proposals include the marginal impact of the fixed future power purchase agreement payment commitments on DEF's capital structure. This additional cost is the direct result of incurring fixed, long-term future payment obligations in the power purchase agreements. Rating agencies make these adjustments to a utility's balance sheet to reflect the existence of debt-like commitments associated with these fixed, long-term payments. Also, Rule 25-22.081(1)(g) F.A.C. requires a utility to include a discussion of the potential for increases or decreases in its cost of capital should a purchase power agreement with a nonutility generator be executed. The cost of imputed debt quantifies that potential. The cost of imputed debt, however, was not the determinative factor in the quantitative evaluation of the most cost-effective option to meet the Company's 2018 reliability need. The Citrus County Combined Cycle Power Plant was the most cost-effective option to meet the Company's reliability need whether or not the cost of imputed debt was considered in the evaluation.

Q. What were the results of the more detailed economic analysis?

A. In CPVRR terms, the Citrus County Combined Cycle Power Plant was found to be approximately $477 million less expensive than the least cost alternative bidder proposal. Exhibit No. ___ (BMHB-14) shows the results of the analysis. This depicts the difference in the total CPVRR associated with each alternative compared to the base case. The results of the detailed financial analysis of the proposals and the

Citrus County Combined Cycle Power Plant demonstrate that the Citrus County Combined Cycle Power Plant is clearly the most cost-effective alternative for supplying generation to meet the needs of the DEF's customers.

Q. Why is the Citrus County Combined Cycle Power Plant less expensive than the other alternatives?

A. The Citrus County Combined Cycle Power Plant is a state-of-the-art, highly efficient, natural-gas fired plant located on a site that takes advantage of adjacent site infrastructure and existing transmission infrastructure providing available transmission capacity for delivery of the Plant's power to DEF's customers. All but one of the bidder proposals involved existing, older and, thus, less efficient natural-gas fired combined cycle units and all of the bidder proposals, including the one new combined cycle generation units, were located at sites that did not take advantage of the available transmission capacity. These are the primary reasons why the Citrus County Combined Cycle Power Plant proved to be more cost effective than any of the bidder proposal resource scenarios, even if the bidder proposals had met DEF's reliability need, which they did not do.

All bidder proposals failed to meet the 1,640 MW reliability need in 2018 and all of them failed to meet that need for the duration of the expected 35-year life of the Citrus County Combined Cycle Power Plant NPGU. This required DEF to add generic units to the bidder proposals to create a resource plan scenario to meet DEF's reliability need. For reasons I described above, the characteristics of these generic combined cycle units were beneficial to the bidders in the resource plan scenarios created around their proposals to meet the Company's reliability need. In the final detailed economic analysis, the more these generic units were used in the resource plan scenarios to meet DEF's reliability need, the more cost effective the plans were, and conversely, the more the bidder proposed units were used in the resource plan scenarios the less cost effective they were.

To illustrate this result, the highest CPVRR and thus the least cost effective bidder proposal resource plan scenario was the one that included all bidder proposed units plus generic units to meet the reliability need. The next least cost effective bidder resource plan was the one that included the three largest bidder units in the resource plan scenario. See Exhibit No. ___ (BMHB-14) to my direct testimony. In sum, the more the bidder proposed units were used in the resource plan the worse the plan was to meet DEF's reliability need.

Q. Did DEF perform any sensitivity analyses?

A. Yes, we performed two sensitivity analyses. One sensitivity analysis was a high natural gas price case and the other was a zero carbon price case. DEF used its high natural gas forecast for the high natural gas price case. The zero carbon price case was an alternative to the Base Case, which included an estimated carbon cost impact based on the Duke Energy forecast. The Duke Energy base carbon cost forecast is within the range of carbon cost forecasts previously used by the Company in its IRP process.

Q. What were the results of the high natural gas price case sensitivity analysis?

A. Exhibit No. ___ (BMHB-14) to my direct testimony also contains the results of the Company's high natural gas price case sensitivity analysis. As shown in Exhibit No. ___ (BMHB-14), the Citrus County Combined Cycle Power Plant NPGU is still the most cost-effective resource for DEF's customers. The next lowest-cost resource scenario including a bidder proposal was $464 million more costly for DEF's customers than the Citrus County Combined Cycle Power Plant NPGU. This is a slightly better CPVRR result for the least cost bidder proposal resource plan scenario than the reference case bidder proposal resource plan scenario, but the result is still less cost effective than the Citrus County Combined Cycle Power Plant NPGU. One significant reason the CPVRR result in this scenario improves slightly is because of the enhanced efficiency of the generic combined cycle plant that follows the bidder proposed unit in the resource plan scenario to meet DEF's reliability need. A second factor is that, with higher gas prices, additional coal generation displaces lower efficiency gas, in some cases from the bidder proposals. The bidder proposed unit does not contribute to the improved cost effectiveness in the high natural gas price case.

Q. What were the results of the zero carbon price case sensitivity analysis?

A. Exhibit No. ___ (BMHB-14) to my direct testimony also contains the results of the Company's zero carbon price case sensitivity analysis. Again, as shown in Exhibit No. ___ (BMHB-14), the Citrus County Combined Cycle Power Plant NPGU still is the most cost-effective resource for DEF's customers. The next lowest-cost resource scenario including a bidder proposal was almost $270 million more costly for DEF's customers than the Citrus County Combined Cycle Power Plant NPGU. Also, again, the reason the CPVRR result in this scenario improves is not because of the bidder proposed unit. The CPVRR results improve in the no carbon price case because of the interplay of the increased dispatch of the existing DEF coal units and the more efficient combined cycle natural-gas fired plant that follows the bidder proposed unit in the resource plan scenario to meet DEF's reliability need. The bidder proposed unit does not contribute to the improved cost effectiveness of the bidder proposal resource plan scenario in the zero carbon price case.

Q. Did you perform any other sensitivity analyses?

A. No, we saw no need to perform any further sensitivity analyses beyond the high natural gas price case and no carbon cost case sensitivity analyses. A low natural gas price case or a higher or several high carbon cost price cases made little sense when all bidder proposed units but one small renewable unit and the Citrus County Combined Cycle Power Plant were natural gas-fired power plants. As a result, all the resource plan comparisons in the detailed economic analysis were gas-on-gas comparisons. The sensitivities that DEF performed, therefore, adequately explained the relationship between the bidder proposed unit resource plan scenarios and the Base Case including the Citrus County Combined Cycle Power Plant NPGU when natural gas and carbon cost prices were changed in the production cost model resource plan scenarios. Further changes in the natural gas price or carbon cost prices were unnecessary for DEF to understand that the Citrus County Combined Cycle

Power Plant remained the most cost-effective resource option for DEF to meet its reliability need.

In fact, the changes in the CPVRR results in the sensitivities that DEF did perform had more to do with the impact of the generic units in the bidder proposed resource plan scenarios than the bidder proposed units in those scenarios. As I explained above, the bidder proposed units had to be combined with generic gas plants in their resource plan scenarios to meet DEF's reliability need. As I also explained above, DEF also assumed these generic units were equally to slightly more efficient in operation as the Citrus County Combined Cycle Power Plant. As a result, changes in the natural gas or carbon cost prices in the detailed economic analyses caused greater changes in the dispatch of these generic units than the bidder proposed unit relative to changes in the dispatch of other units on DEF's system in the Base Case. What DEF was really measuring in CPVRR terms, then, with changes in the natural gas price or carbon cost price was the cost effectiveness of the generic units in the resource plan scenarios that included the bidder proposed units compared to the Base Case with the Citrus County Combined Cycle Power Plant.

Q. Did this complete your economic analysis of the proposals?

A. Yes, it did.

Q. What was the final step in the DEF 2018 RFP process?

A. The final step in the RFP evaluation process was to select the Final List. However, as discussed previously and as stated in the 2018 RFP, in the event the Citrus County

Combined Cycle Power Plant was found to be clearly superior to the other alternatives, a Final List would not be selected. Based on the results of the 2018 RFP evaluation process, the Citrus County Combined Cycle Power Plant was found to be clearly superior to the other alternatives. As a result, DEF announced on May 13, 2014 that the Citrus County Combined Cycle Power Plant was the most cost-effective alternative to serve DEF's customer reliability needs. This announcement concluded the 2018 RFP evaluation process.

VIII. MOST COST-EFFECTIVE ALTERNATIVE.

Q. Is the Citrus County Combined Cycle Power Plant the Company's most cost-effective alternative for meeting its 2018 reliability need?

A. Yes, it is. As I have described, the Company conducted a careful screening of various other supply-side alternatives as part of its IRP process before identifying the Citrus County Combined Cycle Power Plant as its next-planned generating alternative. We were able to screen out less cost-effective supply-side alternatives, identifying the Citrus County Combined Cycle Power Plant as the most cost-effective alternative available to us. Further, through our 2018 RFP process, we determined that the Citrus County Combined Cycle Power Plant was also more cost-effective than any of the proposals made to us.

Q. Why is the Citrus County Combined Cycle Power Plant the most cost-effective alternative?

A. The Citrus County Combined Cycle Power Plant is a highly efficient, state-of-the-art natural-gas fired combined cycle generation plant. This high efficiency yields relatively lower production costs than any other option, creating significant relative fuel savings benefits for DEF's customers. The high efficiency coupled with the favorable site location adjacent to the CREC where site infrastructure can be shared and in the vicinity of existing transmission infrastructure capacity adds substantial benefits to this Plant for DEF's customers. No bidder in response to the 2018 RFP proposed a plant that came close to matching the benefits of the Citrus County Combined Cycle Power Plant for DEF's customers. All bidder proposals fell short of the Company's reliability needs, and even when combined with generic, unplanned and undeveloped plants, the closest bidder proposal resource plan scenario was over $470 million less cost effective for DEF's customers. All bidder proposals combined, which still did not equal DEF's reliability need in 2018 and beyond, was over $1.2 billion less cost effective than the Citrus County Combined Cycle Power Plant. Based on DEF's internal, rigorous IRP process, and the competitive market process of the 2018 RFP, the Citrus County Combined Cycle Power Plant is clearly the most cost effective generation resource for DEF's customers.

IX. BENEFIT TO THE STATE.

Q. Is the Citrus County Combined Cycle Power Plant consistent with the needs of Peninsular Florida?

A. Yes, the Citrus County Combined Cycle Power Plant will assist DEF in meeting its 20 percent planned Reserve Margin and it will assist Peninsular Florida in attaining the 15 percent minimum level of planning reserves targeted for the FRCC region. The Citrus County Combined Cycle Power Plant is further located in the vicinity of transmission infrastructure that provides reliability and stability to the Florida electric grid as determined by the FRCC.

X. CONSEQUENCES OF DELAY.

Q. What will be the impact of delay in implementing the Citrus County Combined Cycle Power Plant?

A. If the Citrus County Combined Cycle Power Plant is delayed, DEF will not be able to meet its 20 percent Reserve Margin requirement in 2018. DEF has retired CR3 and currently must retire CR1 and CR2 and will do so by 2018. DEF, therefore, faces a need for reliable generation in 2018. In addition, these retirements lead to grid reliability issues, recognized by the FRCC, in the event the addition of generation in the vicinity of Citrus County is delayed beyond 2018. To avoid reliability issues for the Florida grid, the Citrus County Combined Cycle Power Plant needs to be built and placed in commercial operation in 2018. In addition, delaying the Citrus County Combined Cycle Power Plant beyond 2018, delays the benefits to customers from the most cost effective generation to meet the Company's reliability need in 2018, and exposes customers to higher cost power to meet their energy needs. For all these reasons, DEF needs to move forward with and place the Citrus County Combined Cycle Power Plant in commercial operation in 2018.

XI. CONSERVATION MEASURES.

Q. Did DEF attempt to mitigate its need for the proposed unit by pursuing conservation measures reasonably available to it?

A. Yes, we did. As I discussed above, the Company identified and has implemented a set of cost-effective DSM programs that have successfully met or exceeded Commission-established goals for years. This success has led to diminishing returns on our investment in DSM programs, however, reducing the availability of and results of cost-effective DSM programs. We anticipate that it will increasingly become more difficult to expand our DSM goals and we have adjusted our proposed future year goals accordingly. We fully expect to achieve all of the proposed future year goals, despite the increasing difficulty in achieving them, but achieving these proposed DSM goals does not mitigate the need for the Citrus County Combined Cycle Power Plant in 2018. The Citrus County Combined Cycle Power Plant is needed even if the Company meets all of its proposed DSM program goals.

XII. CONCLUSION.

Q. Please summarize the benefits of the Citrus County Combined Cycle Power Plant.

A. DEF needs the Citrus County Combined Cycle Power Plant to maintain its electric system reliability and integrity and to provide its customers with adequate electricity at a reasonable cost. By building the Citrus County Combined Cycle Power Plant, the Company will be able to meet its commitment to maintain a 20 percent Reserve Margin, and it will do so by improving not just the quantity, but also preserving the quality, of its total reserves, maintaining an appropriate portion of physical generating assets in the Company's overall resource mix. The Plant also adds diversity to DEF's fleet of generating assets, in terms of natural gas fuel supply diversity, technology, age, and functionality of the Plant. Having exhausted cost effective conservation measures reasonably available to the Company in the timeframe of the need, DEF selected the Citrus County Combined Cycle Power Plant as its most cost-effective alternative for meeting its reliability needs. The Plant will be a state-of-the-art, fuel efficient, environmentally preferable installation that will be located on a site that takes advantage of existing transmission infrastructure and other infrastructure resources at the CREC adjacent to the Plant site. We are pleased to be able to add this unit to the Company's fleet and we urge the Commission to approve our plan to build the Citrus County Combined Cycle Power Plant.

Q. Does this conclude your testimony?

A. Yes, it does.

IN RE: PETITION FOR DETERMINATION OF NEED FOR CITRUS COUNTY COMBINED CYCLE POWER PLANT

BY DUKE ENERGY FLORIDA

FPSC DOCKET NO. 140110-EI

REBUTTAL TESTIMONY OF BENJAMIN M.H. BORSCH

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Benjamin M.H. Borsch and I am employed by Duke Energy Corporation. My business address is 299 1st Avenue North, St. Petersburg, Florida.

Q. What is your position with Duke Energy?

A. I am the Director, IRP & Analytics --- Florida. In this role I am responsible for resource planning for Duke Energy Florida, Inc. ("DEF" or the "Company"). In my capacity as Director, IRP & Analytics --- Florida I was responsible for the Company's Integrated Resource Planning ("IRP") process that led to the selection of the Citrus County Combined Cycle Power Plant as the Company's Next Planned Generating Unit ("NPGU"). I was also responsible for the request for proposals ("2018 RFP") to meet the Company's reliability needs commencing in the summer of 2018 consistent with Florida Public Service Commission ("FPSC" or the "Commission") Rule 25-22.082, F.A.C. (the "Bid Rule"), and the Company's evaluation of the proposals received in response to that 2018 RFP that led to the Company's selection of the Citrus County

Combined Cycle Power Plant as the most cost-effective alternative to meet the Company's reliability need commencing in 2018 consistent with the factors in Section 403.519(3), Florida Statutes.

Q. Have you previously filed direct testimony in this Docket?

A. Yes. I filed direct testimony and exhibits on May 27, 2014 in support of the Company's Petition for Determination of Need for the Citrus County Combined Cycle Power Plant.

Q. Have any intervenors filed direct testimony in this docket?

A. Yes. Calpine Construction Finance Company, L. P. ("Calpine") and NRG Florida LP ("NRG") have intervened and filed direct testimony in this Docket. Calpine filed on its behalf in this Docket the direct testimony of Todd Thornton, John Simpson, and Paul Hibbard. I understand from responses to the Company's discovery requests that Calpine also says that David Hunger is a witness on Calpine's behalf in this Docket, but Dr. Hunger's direct testimony was not filed in this Docket. NRG filed on its behalf in this Docket the direct testimony of Jeffry Pollock, Jim Dauer, and John Morris.

Q. Have you reviewed the direct testimony filed by Calpine and NRG in this Docket?

A. Yes. I reviewed the direct testimony and exhibits filed by both Calpine and NRG in this Docket. NRG filed the exact same direct testimony and exhibits in this Docket that NRG filed in Docket No. 140111-EI, which is the proceeding addressing the Company's Petition for Determination of Cost Effective Generation Alternative to Meet Need Prior to 2018 for Duke Energy Florida, Inc. Calpine filed the exact same direct testimony and exhibits for witnesses Simpson and Hibbard in this Docket that Calpine filed in Docket No. 140111-EI. Only Calpine witness Thornton filed slightly different direct testimony in this Docket than his testimony filed in Docket No. 140111-EI.

II. PURPOSE AND SUMMARY OF REBUTTAL TESTIMONY.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to the direct testimony, exhibits, and recommendations of the Calpine and NRG witnesses <u>in this Docket</u>. This is an important distinction because, as I noted above, the NRG and Calpine direct testimony in this Docket is nearly identical to the NRG and Calpine direct testimony in Docket No. 140111-EI. I also provide rebuttal testimony, with other Company and expert witnesses, to the NRG and Calpine direct testimony in Docket No. 140111-EI.

Q. What is your understanding of the direct testimony filed by NRG in this Docket?

A. It is difficult to discern the exact reason why NRG filed direct testimony in this Docket and what NRG expects the Company and the Commission to do with its direct testimony in this Docket because the NRG witness recommendations, to the extent they exist at all, address the Company's need prior to 2018, which is the subject of Docket No. 140111-EI, not this Docket. NRG witness Pollock recommends in both dockets that DEF should have selected Acquisition 1, the NRG plant acquisition option, instead of the Company's self-build projects, which he identifies as the Suwannee Combustion Turbines ("CTs") and Hines Chillers Power Uprate Project, both of which are the Company's self-build projects in Docket No. 140111-EI, and the Citrus County Combined Cycle Power Plant, which is the self-build project in this Docket. (Pollock Direct Testimony ("Test."), pp. 27-28). NRG, however, did not respond to the 2018 RFP at all, with its "recommended" Acquisition 1, or any other proposal. As a result, neither DEF nor the Commission can consider NRG Acquisition 1 as an alternative to the Citrus County Combined Cycle Power Plant in this Docket.

As best we can tell from NRG's duplicative testimony in both dockets, NRG's position is not that DEF or the Commission should consider NRG's Acquisition 1 proposal as an alternative to the Citrus County Combined Cycle Power Plant in this Docket; rather, NRG's apparent position is that DEF should have selected the NRG Acquisition 1 proposal to meet the Company's need prior to 2018, which is the subject of Docket No. 140111-EI, and that there is no need for the Citrus County Combined Cycle Power Plant in 2018, based on NRG witness Pollock's erroneous conclusions about DEF's load forecasts and planned generation capacity retirements and replacements. In sum, NRG suggests that all the Company needs to do is buy NRG's plant now --- three combustion turbines ("CTs") with only peaking capacity of 471 Megawatts ("MW") --- because the Company's planned replacement capacity will increase rates and the Company's projected load may not materialize so all the Company's planned future generation capacity additions, including the Citrus County Combined Cycle Power Plant, should be deferred. I will address in detail below NRG's erroneous assumptions and conclusions about DEF's load forecast and its planned capacity retirements and replacements.

Q. What is your understanding of the direct testimony filed by Calpine in this Docket?

A. Calpine, as I described above, also filed duplicative testimony in this Docket and in Docket 140111-EI. Calpine witness Thornton filed slightly different testimony in this Docket, however, that makes it clearer that Calpine is arguing that the Company should defer the Citrus County Combined Cycle Power Plant beyond 2018. In other words, Calpine does not challenge the decision to select the Citrus County Combined Cycle Power Plant as the Company's most cost effective alternative to meet its need in 2018. Calpine, like NRG apparently, argues that the Company should have selected its proposal of a power purchase agreement ("PPA") with a purchase option for its plant to meet the Company's need prior to 2018 and, if the Company had done so, the Company could have "possibly" deferred the Citrus County Combined Cycle Power Plant beyond 2018. (Thornton Direct Test., p. 8, lines 8-17; p. 12, lines 1-3). Calpine also challenges DEF's load forecast and its planned generation capacity retirements and additions, in particular, DEF's decision to retire CR1 and CR2, its oldest coal-fired steam generation capacity, in 2018 rather than extending the operation of CR1 and CR2 beyond 2018. (Hibbard Direct Test., pp. 40-42, 43). I will address in detail below Calpine's erroneous assumptions and conclusions regarding DEF's load forecast and planned generation capacity retirements and additions to DEF's system.

Q. Did Calpine submit a proposal to DEF in response to the 2018 RFP?

A. Yes. As Calpine witness Thornton notes in his direct testimony, Calpine submitted a proposal for a long-term PPA for capacity and energy from its Osprey plant in response to the 2018 RFP. Mr. Thornton describes the Calpine proposal in response to the DEF 2018 RFP. (Thornton Direct Test., p. 5, lines 12-20).

Q. Is Calpine asserting that DEF should have selected its proposal in response to the 2018 RFP instead of the Citrus County Combined Cycle Power Plant?

A. No. No Calpine witness argues that DEF should have selected Calpine's proposal for a long-term PPA in response to the 2018 RFP instead of the Citrus County Combined Cycle Power Plant. Calpine witness Thornton asserts that DEF should have selected its July 3, 2014 proposal for a PPA with a purchase option instead of the Company's Suwannee Simple Cycle Project and Hines Chillers Power Uprate Project to meet the Company's need <u>prior to</u>

2018. And, Calpine witnesses Thornton and Hibbard argue that, if DEF had selected the Calpine July 3, 2014 proposal -- instead of the Company's Suwannee Simple Cycle Project and Hines Chillers Power Uprate Project -- the Company may not need the Citrus County Combined Cycle Power Plant in 2018. (Thornton Direct Test., pp. 8, 11-12; Hibbard Direct Test., pp. 40-42, 43). Calpine witnesses Thornton and Hibbard do not assert that the Calpine long term PPA proposal that Calpine submitted in response to the 2018 RFP is more cost effective than the Citrus County Combined Cycle Power Plant to meet DEF's need in 2018.

Q. Did Calpine submit its July 3, 2014 proposal to DEF in response to the 2018 RFP?

A. No. Calpine only submitted a long-term PPA, with no acquisition option, to DEF in response to the 2018 RFP. Mr. Thornton correctly explains that Calpine submitted an offer to sell its Osprey plant to DEF after the response date for proposals to the 2018 RFP. (Thornton Direct Test., p. 5, line 22, p. 6, lines 1-2). This offer to sell the Osprey plant to DEF was materially different from the July 3, 2014 proposal that Calpine apparently now argues that DEF should have accepted to meet the Company's need prior to 2018. The first Calpine offer to sell its plant to DEF was submitted to DEF on May 1, 2014, almost five (5) months after all bid proposals in response to the 2018 RFP were required to be submitted to DEF according to the 2018 RFP schedule. DEF rejected the initial, different May 1, 2014 offer to sell the Osprey plant to

DEF because Calpine did not comply with the schedule requirements in DEF's 2018 RFP.

Q. Is Calpine asserting that DEF should have selected its May 1, 2014 offer or its subsequent offers to sell the Osprey plant to DEF instead of selecting the Citrus County Combined Cycle Power Plant?

A. No, I don't believe so, although Calpine is not absolutely clear about what it is currently proposing in this Docket, and Calpine's description of the history of its proposals to DEF is not entirely accurate. First, Calpine correctly notes that it submitted an acquisition offer late in response to the 2018 RFP, and that DEF indicated it was not going to evaluate that offer in response to the 2018 RFP. Calpine then asserts that it submitted an offer on May 1, 2014 after being notified on April 29, 2014 that DEF had selected the Suwannee Simple Cycle Project and Hines Chillers Power Uprate Project to meet its need prior to 2018. (Thornton Direct Test., p. 6, lines 1-6). Calpine did submit an offer to sell its Osprey plant to DEF on May 1, 2014, but this was the late offer in response to the 2018 RFP, because Calpine specifically said in this May 1, 2014 offer that it wanted to amend its response to the 2018 RFP.

Calpine next says that it submitted another offer to sell its Osprey plant to DEF on June 16, 2014 after being notified by DEF that DEF was proceeding with the Citrus County Combined Cycle Power Plant. Calpine testifies that it amended this June 16, 2014 offer with an updated offer on July 3, 2014. (Thornton Direct Test., p. 6, lines 14-18). While it is accurate that this June

16, 2014 offer was submitted to DEF after DEF notified Calpine (and all other bidders to the 2018 RFP) that DEF had selected the Citrus County Combined Cycle Power Plant at the conclusion of its 2018 RFP, DEF understood from Calpine at the time that this June 16, 2014 offer --- and the updated July 3, 2014 offer --- were submitted as alternatives to the Suwannee Simple Cycle Project and Hines Chillers Power Uprate Project to meet DEF's need prior to 2018.

DEF does not believe Calpine is asserting that DEF should have selected any of its offers to sell the Osprey plant to DEF as an alternative to the Citrus County Combined Cycle Power Plant in response to the 2018 RFP because such a position would be absolutely prohibited under the applicable rules. However, Calpine does not clearly assert this position in its testimony and, if Calpine did, I understand it would be improper under the Commission Bid Rule because only "participants" to the RFP can participate in a need determination proceeding and a "participant" must submit a proposal that complies with the schedule and informational requirements of the 2018 RFP. Rule 25-22.082(2)(d), (16), F.A.C. DEF rejected Calpine's May 1, 2014 offer to sell its Osprey plant to DEF as an amendment to its bid proposal in response to the 2018 RFP because it did not comply with the 2018 RFP schedule requirements.

As a result, DEF believes, as I indicated above, that Calpine's argument in this Docket is that, if DEF had selected Calpine's latest offer to sell its Osprey plant to DEF to meet DEF's need prior to 2018 instead of the

Suwannee Simple Cycle Project and Hines Chillers Power Uprate Project, DEF could possibly defer the Citrus County Combined Cycle Power Plant beyond 2018.

Q. Please provide a brief summary of your rebuttal testimony.

A. NRG and Calpine witnesses do not dispute that the Citrus County Combined Cycle Power Plant is a reliable, cost effective, generation capacity resource addition to DEF's generation system. They do not challenge the Plant's natural gas fuel supply and reliability diversity for DEF's generation fleet and they do not challenge the environmental benefits from adding this state-of-the-art, fuel-efficient, natural gas-fired generation to DEF's system. They also do not dispute the transmission grid reliability and cost-sharing benefits of placing this Plant adjacent to the existing Crystal River Energy Center ("CREC") site and transmission infrastructure. They point to no conservation measures or renewable resources that mitigate the need for the Plant. Indeed, both NRG and Calpine propose that the Company should have selected their natural gas-fired combustion turbine or combined cycle generation capacity proposals, albeit to meet the Company's need prior to 2018, not its need commencing in 2018.

In sum, NRG and Calpine do not dispute that the Citrus County Combined Cycle Power Plant is the most cost effective generation to meet the Company's need commencing in 2018, if the Company needs that generation resource in 2018. What they challenge in this Docket is whether there is a need for the Citrus County Combined Cycle Power Plant in 2018. NRG witness Mr. Pollock makes up load forecast errors that do not exist and arbitrary projects a 50 percent reduction in DEF's load with the resulting and just as arbitrary 50 percent excess capacity, even though he concedes DEF's load could be higher than DEF projected, to suggest that the Citrus County Combined Cycle Power Plant is not needed in 2018. Calpine witness Mr. Hibbard says he found no load forecast errors in the same DEF load forecast, but he argues that actual load conditions may deviate from projected load, relying on such unusual conditions as the Great Recession, to suggest that the Plant could be deferred a year until 2019. Both arguments are not only inaccurate they would, if accepted, simply allow Mr. Pollock and Mr. Hibbard --- or anyone else for that matter --- to argue for any deviations they want in a utility's load forecast and resource plan. This is not resource planning. Neither Mr. Pollock nor Mr. Hibbard identify any real error in the Company's resource planning process or principled reason for the Commission to deviate from the Company's conclusion that the Citrus County Combined Cycle Power Plant is needed in 2018 to meet DEF's reliability need based on DEF's resource planning process.

Mr. Hibbard further suggests that DEF's customers could benefit from the deferral of the Citrus County Combined Cycle Power Plant a year if DEF accepts Calpine's proposal and extends the operation of the Company's oldest coal-fired steam generation units, Crystal River Unit 1 ("CR1") and Crystal River Unit 2 ("CR2") another year, to 2019, rather than retiring the CR1 and CR2 units in 2018 as the Company currently plans. Mr. Hibbard is wrong. First, DEF needs the Citrus County Combined Cycle Power Plant in 2018 regardless of the generation capacity resources selected to meet the Company's need prior to 2018. The Company needs generation capacity resources to meet its need commencing in the summers of 2016 and 2017, and it needs generation capacity commencing in the summer of 2018. These generation capacity resources do not replace each other. Second, there is an additional cost to DEF's customers, not a benefit to customers, for the Company to extend the commercial operation of CR1 and CR2 another year and there are reliability risks, additional environmental emission risks and costs, and other environmental compliance costs associated with continued CR1 and CR2 commercial operation. The continued operation of CR1 and CR2 is not cost effective for DEF's customers.

In sum, NRG and Calpine provide no principled reason to defer the undisputed benefits of the Citrus County Combined Cycle Power Plant. Deferring the commercial operation of this Plant beyond 2018 will simply delay the valuable benefits of this Plant to DEF's customers at an added cost to them. The Company requests that the Commission grant its Petition so that DEF can provide the benefits of the Citrus County Combined Cycle Power Plant to its customers.

Q. Do you have any exhibits to your rebuttal testimony?

A. Yes, I am sponsoring the following exhibits to my rebuttal testimony:

- Exhibit No. ___ (BMHB-15), DEF's load forecasts; and
- Exhibit No. ___ (BMHB-16), DEF's analysis of the costs and benefits of deferring the Citrus County Combined Cycle Power Plant one year and continuing to operate its oldest coal-fired steam generation units, CR1 and CR2 another year, to 2019.

These exhibits were prepared by the Company at my direction and under my control and they are true and correct.

III. DEF EVIDENCE UNCONTESTED BY INTERVENOR TESTIMONY IN THIS DOCKET.

Q. What issues will the Commission decide in this Docket?

A. My understanding is that the Commission will determine, pursuant to the Commission Bid Rule and Section 403.519, Florida Statutes:

(i) Is the proposed Citrus County Combined Cycle Power Plant needed, taking into account the need for electric system reliability and integrity;

(ii) Is the proposed Citrus County Combined Cycle Power Plant needed, taking into account the need for adequate electricity at a reasonable cost;

(iii) Is the proposed Citrus County Combined Cycle Power Plant needed, taking into account the need for fuel diversity and fuel supply reliability;

(iv) Are there any renewable energy sources and technologies or conservation measures taken by or reasonably available to DEF that might mitigate the need for the Citrus County Combined Cycle Power Plant;

(v) Is the proposed Citrus County Combined Cycle Power Plant the most cost-effective alternative available to meet the needs of DEF and its customers; and

(vi) Did DEF reasonably evaluate all alternative scenarios for cost effectively meeting the needs of its customers over the relevant planning horizon.

Q. Do the NRG and Calpine witnesses challenge the need for the Citrus County Combined Cycle Power Plant to meet electric system reliability and integrity?

A. No, some of the NRG and Calpine witnesses challenge whether the Citrus County Combined Cycle Power Plant is needed in 2018, but they do not challenge the fact that, if there is a reliability need for that power in 2018, the Citrus County Combined Cycle Power Plant will meet that reliability need.

Q. Do the NRG and Calpine witnesses challenge the need for the Citrus County Combined Cycle Power Plant, taking into account the need for fuel diversity and supply reliability?

A. No. In fact, both NRG and Calpine propose natural gas-fired CT or combined cycle generation units as alternatives to meet DEF's need prior to 2018 and the NRG and Calpine plants are served by existing natural gas pipelines in the State. These proposals do not have the fuel diversity and fuel supply reliability benefits of the Citrus County Combined Cycle Power Plant that are described in my direct testimony and in the direct testimony of Mr. Patton and Mr. Delehanty in this Docket.

Q. Do the NRG and Calpine witnesses challenge whether there are renewable energy sources and technologies or conservation measures

that could have been taken or that were reasonably available to DEF that might mitigate the need for the Citrus Combined Cycle Power Plant?

A. No. Both NRG and Calpine propose supply-side generation resources to meet DEF's reliability need prior to 2018 and they simply argue that their supply-side generation resources may defer the need for the Citrus County Combined Cycle Power Plant beyond 2018.

Q. If there is a need in 2018 for supply-side generation capacity on DEF's system in the capacity amount of the Citrus County Combined Cycle Power Plant, do the NRG and Calpine witnesses argue that the Citrus County Combined Cycle Power Plant is not the most cost effective alternative for DEF and its customers to meet that need?

A. No. NRG submitted no proposal in response to the 2018 RFP and no NRG witness asserts that there is more cost effective generation than the Citrus County Combined Cycle Power Plant for DEF and its customers, if there is a need in 2018 for that generation. Calpine did submit a proposal in response to the 2018 RFP, but Calpine does not argue that its 2018 RFP proposal is more cost effective than the Citrus County Combined Cycle Power Plant for DEF and its customers if that Plant is needed in 2018.

IV. THERE IS A RELIABILITY NEED FOR THE CITRUS COUNTY COMBINED CYCLE POWER PLANT COMMENCING IN 2018 AND THE CITRUS COUNTY COMBINED CYCLE POWER PLANT MEETS THAT NEED AT A REASONABLE COST FOR ELECTRICITY TO DEF'S CUSTOMERS.

Q. Does DEF need the Citrus County Combined Cycle Power Plant in 2018 to reliably provide electric service to its customers?

A. Yes, DEF needs the Citrus County Combined Cycle Power Plant commencing in 2018 to meet its 20 percent Reserve Margin requirement and to reliably provide electric service to its customers. I explained this need based both on the Company's load forecast and planned generation capacity retirements in my direct testimony and exhibits. As demonstrated in Exhibit No. ___ (BMHB-3) to my direct testimony, there is a need for 820MW of generation capacity commencing in the summer of 2018 that grows to 1,640MW by the summer of 2019. Without the addition of the Citrus County Combined Cycle Power Plant in 2018, DEF's Reserve Margin will fall to 11.7% in 2018 and to 6.9% in 2019, levels far below the 20 percent Reserve Margin. Without the addition of the Citrus County Combined Cycle Power Plant commencing in 2018, DEF cannot continue to reliably provide electricity to its customers.

Q. Do the NRG and Calpine witnesses claim that there are errors in DEF's load forecast or load forecast methodology?

A. NRG witness Pollock appears to claim there is a load forecast error affecting DEF's generation capacity needs, but Calpine witness Hibbard does not claim there are errors in DEF's load forecast or load forecast methodology. (Pollock Direct Test., pp. 21-22). In fact, Calpine witness Hibbard specifically says that he did not find anything wrong with DEF's forecasts of load/energy growth or the timing of resource additions or retirements. (Hibbard Direct Test., p. 42, lines 21-22, p. 43, line 1). He admits there will be growth in peak load and energy requirements. (Hibbard Direct Test., p. 43, lines 3-4). Ironically, despite apparently claiming an error in DEF's load forecast, NRG witness Pollock also concedes it is also possible that load growth could be higher than what DEF projects in its load forecast. (Pollock Direct Test., p. 23, lines 6-9). Both witnesses were provided the same DEF load forecast.

Q. What is the load forecast error that NRG witness Pollock apparently asserts occurred in DEF's load forecast?

A. NRG witness Pollock asserts that DEF's need for capacity prior to 2018 is driven primarily by a more than 1,000MW increase in both wholesale and peak demand from 2013 to 2015. He then claims that, because DEF has not actually experienced such significant load growth in any two years since 2005, there is some unasserted reason to believe there may be a risk of load forecast error in DEF's load forecast. Based on this belief, NRG witness Pollock postulates an arbitrary 50 percent reduction in DEF's load forecast and develops an argument and exhibits to support his unremarkable conclusion that DEF would not need its planned capacity additions in the 2014 to 2023 time frame if you assumed DEF's load was half of what DEF projects it to be in this time frame. (Pollock Direct Test., p. 21, lines 11-16, p. 22, lines 1-21, Exhibit Nos. ___ (JP-2) and ____(JP-3).

Q. Is there an error in DEF's load forecast?

A. No. NRG witness Pollock selectively chooses the years in DEF's load forecast to focus on to generate his claimed greater than 1,000MW increase in 2014-2015 that, according to him, is out of line with DEF's load growth for the last ten years. A more comprehensive evaluation of DEF's load forecast demonstrates that there is no such dramatic deviation in DEF's load forecast and that any deviations that do exist are readily explained by changes in DEF's wholesale contracts and retail load during the period selected by Mr. Pollock.

DEF' s load forecast is contained in the Company's 2014 Ten Year Site Plan ("TYSP") attached as Exhibit No. ____ (BMHB-2) to my direct testimony. True, based on that load forecast in Schedule 3.1, there is a greater than 1,000MW increase in the net firm demand from 2013 to 2015. But, there is a relatively negligible increase of approximately 100MW in net firm demand from 2010 to 2015. In addition, Mr. Pollock chooses as his reference the actual firm generation peak, net of all load control, for 2013, which was a milder than average summer, and then compares that to the 2014 and 2015 projected totals which are necessarily based on normal weather. It matters, then, what years you choose to compare in the Company's load forecast as to what conclusions you may draw from the forecast and when comparing actual past years to projected future years what the actual weather conditions were.

Further, the claimed dramatic changes in the load forecast that NRG witness Pollock claims exist based on the years he selected to compare can be explained in part by changes in the Company's wholesale power contracts during this period of time and the comparison between actual wholesale load and DEF's future commitments.

Additionally, DEF is projecting an increase in retail load from 2013 to 2014 as the Florida economy continues to improve and DEF continues to add customers. This projected increase in retail demand from 2013 is only 200MW greater than the increase in retail load DEF actually experienced from 2012 to 2013 as the Florida economy was just starting to improve after the recession and customer growth was expanding. This continued retail load growth in 2014 and 2015 is certainly reasonable based on what DEF experienced from 2012 to 2013 and what is projected to occur as the Florida economy continues to improve. Again, Calpine witness Hibbard reviewed the same load forecast and found nothing wrong with the Company's load forecast. (Hibbard Direct Test., p. 42, lines 21-22, p. 43, line 1). And, as I explained above, NRG witness Pollock himself admits it is possible load growth could be higher than DEF forecasts it to be. (Pollock Direct. Test., p. 23, lines 6-9).

Q. Is there any reason to conclude from DEF's load forecast as NRG witness Pollock does that there could be a 50 percent reduction in DEF's load growth during the next ten years?

A. No. As I explained above, Mr. Pollock's claimed potential "error" based on his selective reading of DEF's load forecast is not an "error" at all. Even apart from this assertion by Mr. Pollock, however, there is no reasonable basis that I can see for Mr. Pollock to assume a 50 percent reduction in DEF's load growth and he provides none in his direct testimony. He appears to simply have arbitrarily selected 50 percent as his projected reduction in DEF's growth load forecast to make a point. He may draw as many bar charts as he likes showing that if you reduce DEF's projected load growth by 50 percent it results in 50 percent excess capacity, but that result, of course, naturally flows from his arbitrary assumption that there is a 50 percent reduction in DEF's projected load. (Pollock Direct Test., Exhibit Nos. ___ (JP-2) and ____ (JP-3).

Q. If Calpine witness Hibbard found no errors in DEF's load forecast what does he say the Commission should do with DEF's load forecast?

A. While Mr. Hibbard expressly says he is not suggesting that the Commission "second-guess" the Company's planning efforts (Hibbard Direct Test., p. 43, line 5), that is, in effect, exactly what he asks the Commission to do. He argues the Commission should "provide flexibility around the timing of the" Citrus County Combined Cycle Power Plant because he says he has recognized, "based on his decades of experience as a utility regulator and consultant," that load forecasts are based on assumptions and actual load will almost certainly deviate from the prior assumptions about that load. (Hibbard Direct Test., p. 43, lines 6-10). He claims that the one resource that provides the Commission this "needed flexibility" around the timing of the Citrus Combined Cycle Power Plant that he identifies in his testimony is the Company's acceptance of Calpine's proposal for a PPA with a purchase option to meet the Company's need prior to 2018. (Hibbard Direct Test., p. 43, lines 17-23).

Q. Does Mr. Hibbard identify any error in the assumptions in DEF's load forecast or any assumptions that he believes based on his decades of experience should be changed?

A. No. He in fact said there was nothing wrong with the Company's load forecast or the timing of its resource additions and retirements. (Hibbard Direct Test., p. 42, lines 21-22, p. 43, line 1). That must mean Mr. Hibbard finds nothing wrong with the timing of the Citrus County Combined Cycle Power Plant. Mr. Hibbard does refer to the discussion of the accuracy of the utility retail load and energy sales forecast in the Commission's review of the 2013 TYSPs, but it is unclear what he intends the Commission to do with this information. It is hardly surprising that the absolute average error in retail energy sales has increased in "recent years" when Florida has experienced the worst recession since the Great Depression during those years. (Hibbard Direct Test., p. 43, lines 10-12). DEF and other utilities have struggled along with all economic forecasters to properly anticipate the length of the recession and the timing and rate of the recovery. Mr. Hibbard does not suggest that the Commission do anything with this information, and rightly so, because such aberrational economic conditions cannot be accurately predicted and certainly should not be included as an appropriate assumption for a utility's annual load forecasts.

Mr. Hibbard also notes that the "best" forecasts -- which include the Company's load forecasts -- have proven to be accurate to within 1 to 3 percent a year. (Hibbard Direct Test., p. 43, lines 12-16). DEF agrees that it has a demonstrated record of load forecast accuracy. Mr. Hibbard incorrectly concludes, however, that the minor deviations in the accuracy of the annual utility load forecasts can be compounded over several years, thus, leading to significant variations in actual demand. Mr. Hibbard ignores the fact that utilities, including DEF, update their load forecasts regularly, including each year in the utility TYSP. If reasons exist to deviate from prior year forecasts, the load forecasts will be revised, and therefore, there is no statistical or reasonable basis to conclude that prior year deviations in load forecast accuracy can simply be summed up or compounded to determine the overall accuracy of the utility's load forecast. Exhibit No. ___ (BMHB-15) to my rebuttal testimony shows DEF's summer load forecasts over the last six years. This Exhibit shows DEF's updates to anticipate the duration and recovery from the recession as well as other trends in expected demand.

In sum, then, his apparent contention that the Commission should simply depart from the assumptions in the Company's load forecasts and the Company's planned generation capacity additions to meet that projected load in DEF's resource plan because actual load conditions in the future may deviate from the assumed load conditions is unprincipled resource planning. The same assertion could be made to justify any deviation anyone wants to make from every single utility load forecast and resource plan because no forecast is absolutely accurate and actual conditions will always deviate to some degree from forecasted conditions. Despite the fact that actual load may be different from what DEF projects it to be DEF must still plan to meet that future load based on reasonable assumptions about future load conditions and resources to meet that load. That is the very nature of DEF's Integrated Resource Planning ("IRP") process that is presented to the Commission each year in the utility TYSP and reviewed by the Commission to determine if it is suitable for planning purposes. As I described in detail in my direct testimony and in the Company's Need Study, DEF followed this exact IRP process to determine that the Citrus County Combined Cycle Power Plant was needed in 2018 to reliably provide electric service to DEF's customers. Mr. Hibbard has not identified any error in that IRP process or any principled resource planning reason for the Commission to deviate from the Company's conclusions based on that IRP process.

Q. Do the NRG and Calpine witnesses assert any other reason for the Commission to defer the Citrus County Combined Cycle Power Plant beyond 2018?

A. Yes, they both generally assert that DEF is "overbuilding" generation capacity that will increase customer rates, and for that apparent reason, argue that the addition of the Citrus County Combined Cycle Power Plant in 2018 should be deferred beyond 2018. NRG witness Pollock goes so far as to call it an "extreme" makeover of DEF's generation fleet. (Pollock Direct Test., pp. 19-

21). Calpine witnesses Thornton and Hibbard are more specific, but equally devoid of any analytical support, when they argue "by example," that DEF can accept Calpine's PPA with an acquisition option proposal and the Hines Chillers Power Uprate Project to meet DEF's need prior to 2018, defer the retirement of CR1 and CR2 beyond 2018 by a year, and benefit customers. (Thornton Direct Test., p. 8, lines 8-19; Hibbard Direct Test., p. 41, lines 8-23, p. 42, lines 1-2). Both NRG and Calpine ignore the realities DEF faces to reliably operate its generation fleet in the most cost-effective manner in compliance with existing and projected environmental emission and regulation requirements and the benefits that the addition of the Citrus County Combined Cycle Power Plant in 2018 provides customers in meeting these real needs.

Q. Do you agree with Mr. Pollock's characterization of DEF's resource plan as an "extreme" makeover of DEF's generation fleet?

A. Absolutely not. Mr. Pollock acknowledges that one driver in DEF's need for additional generation capacity in 2018 is the retirement of DEF's Crystal River Unit 3 ("CR3") nuclear power plant in 2013. Mr. Pollock also acknowledges that the retirement of CR3 was addressed in the Company's Revised and Restated Stipulation and Settlement Agreement in 2013 ("2013 Settlement Agreement") that he concedes was approved by the Commission. (Pollock Direct Test., p. 19, lines 13-21, p. 20, lines 1-2). Neither NRG nor Mr. Pollock intervened in the proceeding opened to address the 2013 Settlement Agreement to object to DEF's decision to retire CR3 or the treatment of that retirement decision in the 2013 Settlement Agreement. The Commission found the 2013 Settlement Agreement to be in the public interest and approved it in Order No. PSC-13-0598-FOF-EI. NRG and Mr. Pollock have no basis to call this decision "extreme."

Mr. Pollock next includes DEF's decision to retire CR1 and CR2 in his characterization of DEF's resource plan as "extreme." Mr. Pollock acknowledges that the United States Environmental Protection Agency ("EPA") Mercury and Air Toxics Standards ("MATS") rule adversely affects the continued operation of CR1 and CR2 beyond 2015 and that DEF extended the retirement of these units to 2018 with de-rates of the CR1 and CR2 capacity output starting in 2016, but he still includes the retirement of CR1 and CR2 in his alleged "extreme" makeover of DEF's generation fleet. (Pollock Direct Test., p. 20, lines 4-9). I explained in detail the increasing difficulty in continuing to reliably and cost-effectively operate CR1 and CR2 for the benefit of DEF's customers due to existing and increasing environmental emission regulations. I also explained that the Company developed a MATS compliance plan as an amendment to its Integrated Clean Air Compliance Plan to continue the operation of CR1 and CR2 to 2018 that the Commission approved in Order No. PSC-14-0173-PAA-EI (consummating Order No. PSC-14-0218-CO-EI issued May 9, 2014). (Borsch Direct Test., pp. 17-20). Mr. Pollock still calls the Company's planned continued operation of CR1 and CR2 and then retirement in accordance with this Commission-approved plan "extreme."

Finally, Mr. Pollock also calls DEF's plan to retire the oldest combustion turbine peaking units and oldest oil- and gas-fired steam units in its generation fleet "extreme." As I explained in my direct testimony, these retirements include three 1950's vintage oil- and gas-fired steam generation plants and some of the Company's oldest peaking units built in the 1960's and early 1970's. (Borsch Direct Test., pp. 20-21). By the time these units are retired between 2016 and 2018 they will be from over 40 years old to over 60 years old units. These generation plant retirements also have been identified in DEF's TYSPs for at least the past six years. Remarkably, Mr. Pollock ignores the fact that he has recommended that the Company should have selected the NRG acquisition proposal as an alternative to the Company's self-build generation proposals to replace the very generation capacity that he labels "extreme" in his testimony. Remarkably too, Mr. Pollock apparently has no issue with the increase in DEF's customer rates that would occur if the NRG Acquisition 1 proposal had been selected instead of the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project to replace this retired generation capacity and meet DEF's need prior to 2018.

Q. Is DEF "overbuilding" generation capacity?

A. No. There is no reason to conclude that DEF is "overbuilding" generation capacity and the NRG and Calpine witnesses provide none in their direct testimony in this Docket. Bald assertions that DEF is "overbuilding" generation capacity unsupported by any facts certainly do not establish that DEF is building too much generation capacity. DEF must replace the base load generation on its system that CR3 provided prior to CR3's retirement. DEF must also replace the base load and intermediate load generation that CR1 and CR2 now provides when these 1960's vintage coal-fired steam generation units are retired in 2018. This is exactly what the addition of the Citrus County Combined Cycle Power Plant in 2018 does; it replaces the base load generation of CR3 and the base load and intermediate load generation of CR1 and CR2 while also meeting DEF's load growth need in and beyond 2018. Again, bald assertions unsupported by any facts that DEF will have excessive reserve margins with the addition of the Citrus County Combined Cycle Power Plant are meaningless. DEF had demonstrated that the Company's summer Reserve Margin will be just 20.4 percent in 2018 and the Reserve Margin will rise only to 23.6 percent in the summer of 2019 with the addition of the Citrus Combined Cycle Power Plant in 2018. Without the addition of the Citrus County Combined Cycle Power Plant in 2018, DEF's Reserve Margin will fall to 11.7 percent in 2018 and to 6.9 percent in 2019. (Borsch Direct Test., p. 16, Exhibit No. ___ (BMHB-3). This evidence remains uncontradicted by any NRG or Calpine witness in this proceeding.

Mr. Pollock demonstrates that the addition of the Citrus County Combined Cycle Power Plant will not result in excessive Reserve Margins, thus, reflecting an "overbuild" of generation capacity by DEF, when he explains that the net result of DEF's generation capacity retirements and additions between 2013 and 2018 is only an additional 200MW of generation capacity on DEF's generation system at the end of that period. (Pollock Direct Test., p. 21, line 1). This concession by Mr. Pollock also demonstrates that there is tremendous customer risk in his recommendation that the Company should have purchased his client's 470MW peaking plant instead of the Company's self-build generation capacity to meet the Company's need prior to 2018 and simply hoped that DEF's load was at least 50 percent lower than DEF projected it to be in 2018. (Pollock Direct Test., pp. 21-23).

Mr. Pollock's concession demonstrates that there is little margin for error in DEF's load forecast because DEF is in fact largely replacing existing generation capacity that has retired or that will retire in its resource plan in addition to meeting load growth. Indeed, that is probably the reason Mr. Pollock selected 50 percent as his arbitrary projected reduction in load growth in DEF's load forecast --- he needed a big enough reduction in load to overcome the fact that the Citrus County Combined Cycle Power Plant is replacing generation capacity that was or is already on DEF's generation system. Yet, Mr. Pollock does not even attempt to address the rate impact on customers if he is wrong that the Company does not need any resource plan for additional generation in 2018 and beyond because his unsupported and arbitrary assumption that DEF's load could be 50 percent lower than DEF projects it to be turns out to be incorrect. What Mr. Pollock recommends presents DEF's customers with tremendous risk of increased future rates for electric service because it is not resource planning to reliably provide electric service to customers at all.

Q. Will extending the commercial operation of CR1 and CR2 defer the need for the Citrus County Combined Cycle Power Plant in 2018 and benefit DEF's customers as Calpine suggests?

A. No. Calpine witness Hibbard argues that the deferral of the Citrus Combined Cycle Power Plant by one year while accepting Calpine's proposed PPA with an acquisition option for its plant to meet the Company's need prior to 2018 and the extension of the commercial operation of CR1 and CR2 one year "could" benefit customers by $59 million on a Cumulative Present Value Revenue Requirements ("CPVRR") basis. (Hibbard Direct Test., p. 41, lines 12-16). Mr. Hibbard is wrong.

First, as I explain in more detail below, the Company's need prior to 2018 is irrelevant to the Company's need in 2018 and beyond. The Company needs both additional generation capacity prior to 2018 and beyond, and again commencing in 2018 and beyond to continue to reliably serve its customers. DEF's base generation resource plan that includes the Citrus County Combined Cycle Power Plant in 2018 also includes the Suwannee Simple Cycle Project and Hines Chillers Power Uprate Project prior to 2018.

Second, Mr. Hibbard's conclusion that there "could" be $59 million in CPVRR benefits to customers if the Citrus County Combined Cycle Power Plant is deferred one year to 2019 and CR1 and CR2 continue to operate another year beyond 2018 is a simplistic and incomplete calculation of the costs and benefits of this proposal. Indeed, Mr. Hibbard does not even attempt to explain his CPVRR benefits calculation in his direct testimony or by an exhibit to his direct testimony and he even concedes that his calculation does not account for additional environmental emission and regulation costs that he admits DEF faces if DEF continues to operate CR1 and CR2 another year. (Hibbard Direct Test., p. 41, lines 12-23). He simply states without any analysis whatsoever that it is “unclear” to him whether these admittedly additional environmental emission and regulatory requirements would require “significant costs beyond operational changes.” He does not mention the additional costs that would be incurred from these “operational changes.”

Third, DEF has calculated the costs and benefits to customers if DEF deferred the Citrus County Combined Cycle Power Plant one year to 2019 and continued to operate CR1 and CR2 another year. This analysis is included as Exhibit No. ___ (BMHB-16) to my rebuttal testimony. As this detailed analysis shows, a one-year delay in the Citrus County Combined Cycle Power Plant, with the extended one-year operation of CR1 and CR2, causes an increase in the CPVRR to customers of approximately $90 million. This cost increase to customers is driven primarily by the fuel efficiency of the Citrus County Combined Cycle Power Plant compared to the balance of the fleet, including the extended operation of CR1 and CR2 another year. This analysis, however, does not include the potential additional costs to comply with expected additional environmental emission and regulatory requirements that will likely affect the operation of CR1 and CR2 in 2019.

Fourth, this analysis does not take into account the qualitative increased risk from operating CR1 and CR2 another year. The Company’s

MATS compliance plan for the continued operation of CR1 and CR2 even to 2018 is premised on the ability to use site averaging including the operation of Crystal River Unit 4 ("CR4") and Crystal River Unit 5 ("CR5") in its emission compliance program. This means the continued operation of CR1 and CR2 is dependent on the continued and simultaneous operation of CR4 and CR5. This operational dependency between CR1 and CR2 and CR4 and CR5 is atypical of DEF's planned grid reliability because an extended outage at CR4 or CR5 or both plants necessarily requires a curtailment in the operations at CR1 and CR2. DEF accepted this as a reasonable risk from mid-2016 to 2018 because DEF planned to have significant additional generation capacity from the Citrus County Combined Cycle Power plant on line at that time, thus, alleviating this risk. Deferring this additional needed generation capacity another year simply to continue to operate CR1 and CR2 in this manner increases this risk with no further mitigation or realized benefits for DEF and its customers.

Mr. Hibbard is wrong in his assertion that these reliability concerns "may" be reduced if the full energy output of Calpine's plant and the Hines plant, presumably with the Hines Chillers Power Uprate Project, again, without any analysis whatsoever. (Hibbard Direct Test., pp. 41-42). All Mr. Hibbard is really saying here is that if CR4 or CR5 or both are in an extended outage and the output of CR1 and CR2 must be curtailed, the loss in this generation capacity "may" be offset by the Calpine plant and the Hines plant with the Hines Chillers Power Uprate Project. This is mere supposition on Mr.

Hibbard's part and it does not justify continued reliance in 2019 on the dependent operational reliability between CR1 and CR2 and CR4 and CR5 when DEF has a readily available, cost effective means of remedying that operational reliability risk with the addition of the Citrus County Combined Cycle Power Plant.

Finally, as I explained above, DEF's analysis of the costs and benefits of deferring the Citrus Combined Cycle Power Plant and continuing to operate CR1 and CR2 another year in Exhibit No. ___ (BMHB-16) does not include the additional operational costs from additional environmental emission and regulatory requirements in 2019. These are the same requirements that Mr. Hibbard acknowledges exists in his direct testimony, but claims without any support that he is "unclear" that they will result in "significant" costs to customers in 2019. By 2019 the Florida Department of Environmental Protection ("DEP") will be implementing the one-hour National Ambient Air Quality Standard ("NAAQS") for sulfur dioxide ("SO2") that will require additional environmental compliance equipment and measures to continue to operate CR1 and CR2 in 2019. DEF's compliance plan to meet these additional one-hour NAAQS for SO2 at CR1 and CR2 is to retire the units before 2019 to avoid incurring these additional costs.

DEF must also face additional compliance measures at CR1 and CR2 in 2019 to comply with EPA's regulatory amendments to Section 316(b) of the Clean Water Act. The 2014 Section 316(b) regulations require facilities like CR1 and CR2 to include measures or controls to eliminate or reduce fish and aquatic organism impingement in cooling water intake structures for the facilities. While DEF would not face the significant costs associated with long term compliance, ongoing studies and mitigation measures will have some cost. The specific cost would depend on future discussions with the Florida DEP since DEP will determine the requirements based, in part, on DEF's commitment to a retirement date. Faced with these additional costs to continue to operate CR1 and CR2 beyond 2018, and the anticipated fleet production cost savings associated with operation of the Citrus Count y Combined Cycle Power Plant, DEF reasonably concluded the most cost effective option for its customers was to retire CR1 and CR2 when the Citrus County Combined Cycle Power Plant is added to the generation system in 2018.

Q. Does the Company's selection of the most cost effective generation capacity to meet its need prior to 2018 impact DEF's need for the Citrus County Combined Cycle Power Plant in 2018?

A. No. As I explained briefly above, the Company needs the Citrus County Combined Cycle Power Plant in 2018 regardless of the selection of generation capacity to meet the Company's need prior to 2018. The Citrus County Combined Cycle Power Plant provides needed base load and intermediate generation capacity commencing in 2018 and continuing beyond 2018 primarily because it is replacing the retired CR3 nuclear power plant and the CR1 and CR2 coal-fired plants that will be retired in 2018. The Company's need prior to 2018 is primarily a need for additional peaking capacity, indeed, DEF plans to meet that need by adding additional CT peakers at its Suwannee power plant site and by adding chillers to the Hines power block units that will increase the summer generation capacity at the Hines plant. The Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project are included in the Company's base generation resource plan that includes the addition of the Citrus County Combined Cycle Power Plant in 2018. The Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project will continue to provide generation capacity to meet the Company's need from 2016 to 2018 and beyond. Both the NRG and the Calpine witnesses are simply incorrect or misleading in their assumptions or statements about the claimed "flexibility" of their proposed plants to somehow impact the need for the Citrus County Combined Cycle Power Plant in 2018. Arguments regarding "flexibility" indicate that DEF might be able to shed the generation from these plants in the future, which would clearly not be the result of the acquisitions suggested by the parties. Arguments that accepting the proposal of one of the parties would allow DEF to defer the in-service date of the Citrus County Combined Cycle Power Plant are not supported by DEF's need resulting from the retirement of the three Crystal River units, and DEF has shown that extension of CR1 and CR2 to 2019 is not cost effective. Exhibit No. __(BMHB-16).

V. CONCLUSION.

Q. What do you make of the NRG and Calpine witness arguments in this Docket involving DEF's Petition for Determination of Need for the Citrus County Combined Cycle Power Plant?

A. I believe it is important to point out that no NRG or Calpine witness expresses the opinion that the Citrus County Combined Cycle Power Plant is not a reliable, cost effective, generation capacity resource addition to DEF's generation system for DEF's customers that improves the quality of DEF's physical reserves and adds diversity to DEF's generation fleet in terms of natural gas fuel supply diversity, technology, age, and functionality of the Plant. These and other quantitative and qualitative benefits, such as the DEF and Florida transmission grid reliability and environmental benefits associated with the addition of the Citrus County Combined Cycle Power Plant to DEF's system, are not challenged.

For example, no witness challenges or even discusses the benefits of adding the Plant in Citrus County adjacent to the Crystal River Energy Center ("CREC") where the Plant can take advantage of existing CREC infrastructure resources and transmission facilities in that area. No witness challenges the costs for the Citrus County Combined Cycle Power Plant, the 2018 RFP, or the 2018 RFP evaluation that resulted in the determination that the Citrus County Combined Cycle Power Plant is the most cost effective alternative available to meet the needs of DEF and its customers.

The Citrus County Combined Cycle Power Plant simply is the most cost effective generation resource to meet customer needs commencing in 2018. No NRG or Calpine witness says that the Citrus County Combined Cycle Power Plant is not the most cost effective generation resource to meet the needs of DEF's customers. Their testimony, at most, is that the undisputed benefits of this Plant should be deferred at least a year, but as I have demonstrated, that deferral will simply delay the valuable benefits of this Plant to DEF's customers at an added cost to them. No NRG or Calpine witness has put forth any valid reason for DEF's customers to incur greater cost and suffer the delayed benefits from deferring the Citrus County Combined Cycle Power Plant even one year. The Company, accordingly, requests that the Commission grant its Petition for Determination of Need for the Citrus County Combined Cycle Power Plant so that DEF can provide this beneficial generation resource to its customers.

Q. Does this conclude your rebuttal testimony?

A. Yes.

IN RE: PETITION FOR DETERMINATION OF COST EFFECTIVE GENERATION ALTERNATIVE TO MEET NEED PRIOR TO 2018 FOR DUKE ENERGY FLORIDA, INC.

BY DUKE ENERGY FLORIDA, INC.

FPSC DOCKET NO. _________

DIRECT TESTIMONY OF BENJAMIN M. H. BORSCH

I. INTRODUCTION AND QUALIFICATIONS.

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

A. My name is Benjamin M. H. Borsch and I am employed by Duke Energy Corporation. My business address is 299 1st Avenue North, St. Petersburg, Florida.

Q. Please tell us your position with Duke Energy and describe your duties and responsibilities in that position.

A. I am the Director, IRP & Analytics – Florida. In this role, I am responsible for resource planning for Duke Energy Florida, Inc. ("DEF" or the "Company"). I am responsible for directing the resource planning process in an integrated approach to finding the most cost-effective alternatives to meet the Company's obligation to serve its customers in Florida. As a result, we examine both supply-side and demand-side resources available and potentially available to the

Company over its planning horizon, relative to the Company's load forecasts, and prepare and present the annual Duke Energy Florida Ten-Year Site Plan ("TYSP") documents that are filed with the Florida Public Service Commission ("FPSC" or the "Commission"), in accordance with the applicable statutory and regulatory requirements. In my capacity as the Director, IRP & Analytics – Florida, I oversaw the completion of the Company's most recent TYSP document filed in April 2014 and the Company's 2013 TYSP. I was also responsible for the Company's evaluation of options to meet its needs for reliable electric power prior to 2018.

Q. Please summarize your educational background and employment experience.

A. I received a Bachelor's of Science and Engineering degree in Chemical Engineering from Princeton University in 1984. I joined Progress Energy in 2008 supporting the project management and construction department in the development of power plant projects. In 2009 I became Manager of Generation Resource Planning for Progress Energy Florida, and following the 2012 merger with Duke Energy accepted my current position. Prior to joining Progress Energy, I was employed for more than 5 years by Calpine Corporation where I was Manager (later Director) of Environmental Health and Safety for Calpine's Southeastern Region. In this capacity, I supported development and operations and oversaw permitting and compliance for several gas fired power plant projects in nine states. I was also employed for more than 8 years as an environmental consultant with projects including development, permitting and compliance of power plants and transmission facilities. I am a professional engineer licensed in Florida and North Carolina.

II. PURPOSE AND SUMMARY OF TESTIMONY.

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

A. I am testifying on behalf of the Company in support of its Petition for Determination of Cost Effective Alternative to Meet Need prior to 2018 for Duke Energy Florida. I will provide an overview of the generation alternatives that the Company proposes to build to meet its need prior to 2018 in the most cost-effective manner for its customers. I will discuss the resource planning process and how that led the Company to identify this need prior to 2018 and I will explain the steps the Company took to identify available, potentially superior supply-side alternatives. Next, I will explain the Company's evaluation of these generation alternatives and set forth the reasons why the Company's self-build generation options are the most cost-effective resource options to meet the Company's need prior to 2018. I will conclude my testimony by explaining the Company's decision to proceed with its self-build generation options to meet its need prior to 2018 in the most cost-effective manner for the Company's customers.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. I am sponsoring the following exhibits to my testimony:

- Exhibit No. ___ (BMHB-1), a copy of the Florida Reliability Coordinating Council ("FRCC") Evaluation of Transmission Impact of the United States Environmental Protection Agency ("EPA") Mercury and Air Toxics Standard ("MATS") --- Transmission Impact Study for Shutdown of Crystal River Unit 1 ("CR1") and Crystal River Unit 2 ("CR2") with retirement of Crystal River Unit 3 ("MATS Study");
- Exhibit No. ___ (BMHB-2), the Company's current, April 2014 TYSP;
- Exhibit No. ___ (BMHB-3), the Company's near-term summer and winter load forecast;
- Exhibit No. ___ (BMHB-4), the Company's forecast of summer peak demands and reserves with and without additional generation capacity in the summers of 2016 and 2017;
- Exhibit No. ___ (BMHB-5), the Company's forecast of physical and dispatchable demand-side resource reserves through the summers of 2016 and 2017;
- Exhibit No. ___ (BMHB-6), the generation options evaluated to contribute to the Company's capacity needs in the summers of 2016 and 2017;
- Exhibit No. ___ (BMHB-7), a confidential chart of the supply-side generation proposals evaluated by the Company to meet its capacity needs in the summers of 2016 and 2017;
- Exhibit No. ___ (BMHB-8), the Company's initial detailed economic analysis results for the most cost-effective generation option to meet the Company's capacity needs in the summers of 2016 and 2017;

- Exhibit No. ___ (BMHB-9), the Company's cost sensitivity analysis results based on the initial detailed economic analysis;
- Exhibit No. ___ (BMHB-10), the Company's final detailed economic analysis results for the most cost-effective generation option to meet the Company's capacity needs in the summer of 2016 and 2017; and
- Exhibit No. ___ (BMHB-11), the Company's analysis of natural gas price and carbon cost ("CO2") sensitivities to the final detailed economic analyses.

Each of these exhibits was prepared under my direction and control, and each is true and accurate.

Q. Please summarize your testimony.

A. DEF needs the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project by the summer of 2016 and 2017, respectively, to meet its 20 percent Reserve Margin commitment and to serve its customers' future electrical power needs in a reliable and cost-effective manner. Faced with generation plant retirements and additional customer and peak load demand, the Company determined in its resource planning process that the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project were superior to any other alternative, including additional renewable energy resources and conservation measures, to meet the Company's near-term generation capacity needs.

The Company further evaluated these projects against power purchase agreement and generation facility acquisition proposals from third-party generators, and none of these proposals compared more favorably, on a quantitative and qualitative basis, to the Company's Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project. DEF has demonstrated that the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project are the best alternatives for maintaining DEF's electric system reliability and integrity, and providing its customers with adequate electricity at a reasonable cost, by the summer of 2016 and 2017, respectively. We, accordingly, request that the Commission approve the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project as the most cost-effective alternatives to meet the Company's need in 2016 and 2017.

III. OVERVIEW OF THE COMPANY'S NEED AND PETITION.

Q. Can you generally explain the Company's need that led to this Petition?

A. Yes. The Company faced resource planning decisions leading up to and early in 2013 that affected the Company's near-term need in the ten-year planning period for generation capacity to meet customer energy needs. As a result, during the Company's annual integrated resource planning analysis, the Company identified substantial generation capacity needs in the near term, beginning in 2016. This analysis was first reflected in the Company's 2013 TYSP. The Company's continuing resource planning process and analysis that resulted in its 2014 TYSP confirmed this need beginning in 2016.

Q. What were these resource planning decisions?

A. In February 2013, the Company decided to retire its Crystal River Unit 3 nuclear power plant ("CR3"). The Company also decided to retire its CR1 and CR2 (also "CRS" for "Crystal River South"), coal plants earlier than originally planned. These generation retirements account for over 1,500 MegaWatts ("MW") of summer generation capacity on DEF's system.

The Company planned to retire its CR1 and CR2 coal plants in 2020. The issuance of new EPA environmental regulations under the Clean Air Act affected the Company's planned retirement of CR1 and CR2. As a result of these new environmental regulations, the Company faced the retirement of CR1 and CR2 as soon as 2015, but, as explained in more detail below, the Company now plans to retire CR1 and CR2 in 2018. Still, these and other retirement decisions and the Company's response to them, coupled with the Company's load growth, create a near term need for generation, commencing in 2016.

Q. What were the environmental regulations that impacted the Company's planned retirement of its Crystal River South coal plants?

A. The EPA issued its MATS regulations in December 2011 and these regulations became effective in April 2012. The EPA MATS regulations are designed to reduce mercury, other metals, and acid gas emissions from coal- and oil-fired power plants. Compliance with MATS is required three years after the effective date, or by April 2015. A one-year MATS compliance extension is available under certain conditions from the Florida Department of Environmental

Protection ("FDEP"). The Crystal River Units 1 and 2 coal-fired units cannot meet the emissions requirements for MATS as currently configured and without changes in the coal fuel source for the units.

Q. What impact did these EPA regulations have on the Company's retirement decision for its Crystal River South coal plants?

A. Initially, the Company faced the retirement of CR1 and CR2 as early as 2015, with a possible extension to 2016. This extension was granted by the FDEP earlier this year, based on the time DEF needed to complete modest upgrades to the CR1 and CR2 units under a plan the Company developed for limited continued operation of CR1 and CR2 in compliance with MATS. The FDEP also recognized that continued operation of CR1 and CR2 deferred or resolved significant Florida electric grid reliability issues identified by the FRCC in its MATS study completed in 2013.

The FRCC MATS Study evaluated the impact of a MATS-required shutdown of CR1 and CR2 on the reliability of the Florida Bulk Electric System ("BES"). The FRCC is responsible for ensuring that the Florida BES is reliable and adequate. The FRCC concluded, based on its analysis in 2013, that shutting down CR1 and CR2 in 2015 as a result of MATS would result in significant, adverse transmission impacts to the BES. The FRCC found that, at a minimum, the one-year extension of the MATS compliance deadline was needed to provide time to alleviate the significant transmission reliability issues that the FRCC identified in the MATS Study. The FDEP considered the FRCC conclusions in its decision to grant the one-year extension to 2016 for CR1 and CR2 to comply with MATS. A copy of the FRCC MATS Study is attached as Exhibit No. ___ (BMHB-1) to my direct testimony.

During 2013, the Company further evaluated the continued operation of Crystal River South in compliance with MATS and other environmental regulations and determined that the Company could continue to operate CR1 and CR2 beyond 2016 with certain modifications to the units and a change to lower sulfur coal blends burned at the plants. The Company evaluated this plan against other options, concluded that the plan was the most cost-effective option, and presented this plan to the Commission in December 2013 as a modification to its Integrated Clean Air Compliance Plan. More detail on the Company's compliance strategy for CR1 and CR2 in response to MATS and other environmental regulations is provided in the Company's petition to modify its Integrated Clean Air Compliance Plan filed in Docket No. 130007-EI. The Commission approved this modification to its Integrated Clean Air Compliance Plan in Order No. PSC-14-0173-PAA-EI (consummating Order No. PSC-14-0218-CO-EI issued May 9, 2014).

The Company now plans to continue commercial operation of CR1 and CR2 until 2018 in compliance with the Commission-approved modification to its Integrated Clean Air Compliance Plan. This decision reduces the generation capacity the Company needs prior to 2018, but the Company still needs generation capacity to reliably serve its customers commencing in this time period.

Q. What were the Company's other generation retirement decisions?

A. The Company projected the retirement of some of its oldest combustion turbines in its fleet in 2014 and 2016. These projected retirements were identified in the Company's resource planning process in the late 2000's and continued to be part of the Company's resource plans in its 2013 and 2014 TYSPs. These combustion turbines were installed in the late 1960's and early 1970's at Avon Park, Turner, and Rio Pinar. They collectively provide 133 MW of summer generation capacity to DEF's system. They are smaller, less efficient combustion turbines and they are increasingly more costly to operate and maintain. The Company will retire all of these combustion turbine units by 2016.

The Company also plans to retire its three 1950's vintage oil- and gas-fired steam generation plants at the Company's Suwannee power plant site by 2016. These are small units, collectively providing 128 MW of summer capacity to DEF's system. These units were slated for retirement in 2018 as they approach the end of their life cycle. DEF will retire these units in 2016 to reduce the cost of the transmission upgrades needed for installation of the proposed peakers.

These generation plant retirements contribute to the Company's generation capacity needs prior to 2018. Coupled with load growth identified in the Company's 2013 and 2014 TYSPs, the Company needs additional generation capacity prior to 2018 to reliably serve customers.

Q. What did the Company do in response to this identified need in 2016?

A. The Company evaluated several alternative generation options to meet this need including (i) construction of new generation; (ii) purchases from or acquisitions of existing generation plants owned by other companies; and (iii) power uprate projects at existing generation plants on the Company's system. The Company identified a need up to 1,150 MegaWatts ("MW") of additional generation capacity beginning in 2016 and established a process for Commission review of the Company's evaluation of this need in its Revised and Restated Stipulation and Settlement Agreement ("2013 Settlement"). In the 2013 Settlement, the Company agreed to evaluate and compare the most cost effective alternative to satisfy its generation capacity needs prior to year end 2017 through its Integrated Resource Planning ("IRP") methodology and to present this evaluation to the Commission.

Q. Does the Company still need up to 1,150MW of generation commencing in 2016?

A. No. As I explained above, the Company's decision to complete projects necessary to permit the continued operation of CR1 and CR2 with alternative, low sulfur coal fuel sources and site averaging to comply with MATS extends the operation of CR1 and CR2 to 2018. This decision reduces the Company's generation capacity needs commencing in 2016. As a result, the Company no longer needs up to 1,150 MW of generation capacity commencing in 2016. The Company's need now is approximately 280 MW of summer generation capacity commencing in 2016 that increases to 470 MW in the summer of 2017.

Q. What is the Company's plan to meet its generation needs commencing in 2016?

A. The most cost-effective resource plan to meet the Company's summer generation capacity needs commencing in 2016 includes the construction of a new 320 MW simple cycle combustion turbine plant consisting of two F class combustion turbine units at the Company's Suwannee power plant site. This is called the Suwannee Simple Cycle Project. This plan also includes the installation of a 220 MW chillers power uprate project for the Company's existing natural gas-fired, combined cycle power blocks at the Company's Hines Energy Complex ("HEC"). This is called the Hines Chillers Power Uprate Project. This is the most cost-effective generation resource plan available to the Company for its customers to meet the Company's near-term generation needs commencing in 2016 based on both price and non-price attributes.

Q. Is the Company's decision with respect to its generation needs prior to 2018 consistent with the 2013 Settlement Agreement?

A. Yes. The Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project are the types of generation options specifically contemplated in the 2013 Settlement Agreement to meet the Company's generation capacity needs prior to 2018. The Company's decision to select these projects to meet its reliability need is the result of the IRP methodology that the Company agreed in the 2013 Settlement Agreement to use to evaluate and compare the most cost effective alternative to satisfy its generation capacity needs prior to year end 2017 and present to the Commission for approval. Indeed, the parties to the 2013 Settlement Agreement agreed that DEF could seek Commission approval for the costs of additional generation to meet a need up to 1,150 MW in the 2013 Settlement Agreement, however as I explained above, the Company's ability to cost-effectively comply with MATS and extend the commercial operation of Crystal River South has reduced the Company's estimated need prior to 2018 from up to 1,150 MW to approximately 500 MW. The Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project are the most cost-effective generation options to meet that need.

DEF has met with the parties to the 2013 Settlement Agreement several times to explain DEF's approach to its generation needs prior to 2018 and, ultimately, DEF's analyses and decision to meet that need consistent with the terms of the 2013 Settlement Agreement. No party to the 2013 Settlement Agreement has expressed to DEF that DEF has not complied with the 2013 Settlement Agreement.

IV. THE COMPANY'S RESOURCE PLANNING PROCESS.

Q. Please explain the Company's Resource Planning Process.

A. The IRP process is an integrated process in which the Company seeks to optimize its supply-side and demand-side options into an integrated optimal plan designed to deliver reliable, cost-effective power to DEF's customers. On an annual basis, and when circumstances materially affecting the Company's current resource plan change, we evaluate the relationship of demand and supply against the

Company's reliability criteria to determine if additional capacity is needed. Based on that evaluation, we develop the most cost-effective overall plan, which becomes the Company's Integrated Optimal Plan. This Integrated Optimal Plan is typically presented to the Commission in April each year in the Company's annual TYSP filing. The Company's current 2014 TYSP is included as Exhibit No. ___ (BMHB-2) to my direct testimony.

Q. What reliability standards does the Company use to determine the need for additional resources?

A. DEF plans its resources in a manner consistent with utility industry resource planning practices, and employs both deterministic and probabilistic reliability criteria in the resource planning process. The Company plans its resources to satisfy a minimum Reserve Margin criterion and a maximum Loss of Load Probability ("LOLP") criterion. DEF has used dual reliability criteria since the early 1990s in its IRP process and this practice has been accepted by the Commission. DEF uses both the Reserve Margin and LOLP planning criteria to ensure that its resource plan has sufficient capacity available to meet customer peak demand, and to provide reliable generation service under all expected load conditions in the Company's service territory.

Q. Why are reserves needed?

A. Utilities require reserves to provide a margin of generating capacity above the firm demands of their customers in order to provide reliable electric service.

Periodic scheduled outages are required to perform maintenance and inspections of generating plant equipment. Also, at any given time during the year, some plants will be out of service due to unanticipated equipment failures resulting in forced outages of generation units. Adequate reserves must be available to accommodate these outages and to compensate for higher than projected peak demand due to forecast uncertainty and abnormal weather. In addition, some capacity must be available for operating reserves to maintain the balance between supply and demand on a moment-to-moment basis. For all these reasons, DEF plans generating capacity reserves into its optimal resource plan.

Q. What is DEF's Reserve Margin in its Integrated Resource Plan?

A. DEF's current minimum Reserve Margin threshold is 20 percent. The Reserve Margin is a deterministic measure of reliability. Reserve margin is the amount of capacity that a utility maintains above the peak forecast load expressed as a percentage of the load. The Commission approved this minimum Reserve Margin threshold for the investor-owned utilities in peninsular Florida in Commission Order No. PSC -99-2507-S-EU.

Q. What is LOLP and what does it measure?

A. The LOLP is a probabilistic criterion that measures the probability that a utility company will be unable to meet its load throughout the year. Where Reserve Margin considers only the peak load and amount of installed resources, LOLP also takes into account a utility's load shape, generating unit sizes, capacity mix, maintenance scheduling, unit availabilities, and capacity assistance available from other utilities. A standard LOLP probabilistic reliability threshold commonly used in the electric utility industry, and the criterion employed by DEF, is a maximum of one day in ten years loss of load probability. In most cases, however, the need for additional generation capacity is triggered by the 20 percent Reserve Margin requirement before the LOLP criterion is considered. DEF's need for additional generation capacity prior to 2018 is also based on DEF's 20 percent Reserve Margin requirement.

Q. How did you start your resource plan that led to the identification of your need beginning in 2016 based on your reliability criteria?

A. As I explained above, there were certain retirement decisions, in particular, the retirement of the Company's CR3 nuclear plant, and the planned retirement of the Company's Crystal River South coal plants around changing environmental requirements, that drove the Company's near-term reliability needs as the Company entered 2013. The generation capacity need resulting from these decisions was coupled with additional load growth as a result of the Company's routine update of its forecast of system load growth for the next ten years as part of the normal IRP process. The Company's load forecast draws on the collection of certain input data, such as population growth, fuel prices, and interest and inflation rates. The load forecast is then developed based on economic and demographic assumptions that impact future energy sales and customer demand. The Company's load forecast is another key driver of the Company's resource plan in the IRP process. The Company's load forecast methodology is described in detail in Chapter 2 of the Company's 2014 TYSP, which is Exhibit No. ___ (BMHB-2) to my direct testimony.

Q. Can you generally describe DEF's system demand and energy forecasts?

A. Yes. The Company's summer firm demand is expected to grow to 9,149 MW by the summer of 2016, which represents approximately a 3.8 percent growth rate from 2014. The net energy for load is projected to grow to 41,098 GWh in 2016, which represents approximately a 3.3 percent growth rate from 2014. The demand and energy forecasts are discussed in more detail in Chapter 2 of the Company's 2014 TYSP, which is Exhibit No. ___ (BMHB-2) to my direct testimony.

Q. What is the impact of the Company's load forecast on the Company's generation resource needs?

A. The Company will experience load growth as the Florida economy recovers from the last recession. DEF expects both more customers and growth in energy demand in the near term, through 2017, albeit at a slower pace than customer and energy demand growth before the recession. This is a change from the loss of customers and reduced demand at the height of the recession in 2009. The Company has slowly recaptured the ground lost during the recession and expects continued growth in customers and demand. This growth, especially in summer peak demand on the Company's system, is one driver of the need for additional generation. Additionally, as I explained above, the need for additional generation is driven by the Company's decisions to retire generation capacity on its system. Together, the Company's projected capacity needs resulting from the Company's projected load growth, and existing and planned retirements, among other factors, demonstrate a need for additional capacity of approximately 280 MW in the summer of 2016 increasing to a need for 470 MW by the summer of 2017. Exhibit No. ____ (BMHB-3) is a summary of the Company's summer load forecast during this period.

Q. What is the impact on the Company's Reserve Margin?

A. DEF needs additional generation in the summer of 2016 and 2017 to meet its 20 percent minimum Reserve Margin requirement. Exhibit No. ___ (BMHB-4) shows DEF's forecast of summer peak demand and reserves, with and without any summer capacity additions. For the period from the summer of 2015 to the summer of 2017, DEF projects that the growth in firm summer peak demand will average approximately 132 MW a year with a projected peak in 2016 of 9,149 MW and in 2017 of 9,307 MW. The exhibit also shows that DEF will have a total generating capability of approximately 11,012 MW by the summer of 2016 and 11,232 MW by the summer of 2017. This capacity includes the installation of the Suwannee Simple Cycle Project in 2016 and the Hines Chillers Power Uprate Project in 2017.

As demonstrated in this exhibit, without these capacity additions, DEF's Reserve Margin will decrease to 16.9 percent in the summer of 2016 and 14.9

percent by the summer of 2017. DEF maintains its Reserve Margin for its summer (and winter) peak demands to ensure reliable electric service to its customers. DEF needs additional generation capacity in the summer of 2016 and the summer of 2017 to meet its obligation to provide reliable electric service to its customers.

Q. Did the Company consider non-generating alternatives to meet the Company's capacity need commencing in 2016?

A. Yes, energy conservation and direct load control programs are always a part of the Company's IRP process and they were considered in connection with the Company's near-term generation capacity need commencing in 2016. The Company's current demand-side management ("DSM") programs were included in the Company's Base Generation Expansion Plan that contains the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate project. As evidenced by the inclusion of these projects in the Company's Base Generation Expansion Plan, however, The Company's current DSM programs cannot replace or defer the Company's need for additional generation on its system to meet the Company's generation capacity needs commencing in 2016.

Q. What are the Company's current DSM programs?

A. DEF's current DSM programs were essentially set forth in the DSM Plan approved by the Commission in Order No. PSC-11-0347-PAA-EG in August 2011. In this Order, the Commission modified the Company's DSM Plan, effectively approving the Company's DSM programs that were in effect in August 2011. In 2012, additional revisions to four Company DSM programs resulting from changes in the Florida Building Code were approved, otherwise the Company's current DSM programs are the same as the programs the Commission approved in Order No. PSC-11-0347-PAA-EG. With these revisions, DEF's Commission-approved DSM Plan consists of six residential programs, eight commercial and industrial programs, one research and development program, and six solar pilot programs. These DSM programs will continue to be offered to the Company's customers through 2014 as the Company's current DSM Plan extends through the end of the year. A more detailed description of the Company's DSM programs is contained in the Company's 2014 TYSP attached as Exhibit No. ___ (BMHB-2) to my direct testimony.

Q. Did the Company's continuing IRP planning process in 2014 reveal new or revised DSM programs or measures that satisfied or deferred the Company's generation capacity needs commencing in 2016?

A. No. DEF performed the DSM evaluations necessary for the Commission's current DSM goals docket that will set DEF's future DSM goals for the period 2015 to 2024. Based on the results of that evaluation, there are no additional DSM measures or programs that can replace or defer the Company's need for additional generation capacity prior to 2018 to reliably serve DEF's customers. There is no reason to conclude, then, that the Company's determination that it needs additional supply-side generation capacity commencing in 2016 will be affected by the outcome of the current DSM goals docket.

Over the next ten years the Company's proposed conservation goals are generally lower than the existing DSM goals. All other things being equal, then, the Company's near-term DSM goals cause an increase in DEF's firm summer peak demand in 2016 and 2017, and, therefore, further establish the need for the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project to meet DEF's reliability needs in 2016 and 2017.

DEF's proposed DSM Plan reflects the successful implementation of cost-effective DSM programs by the Company for the past thirty years to reduce energy demand and energy consumption and therefore avoid the need for new generation. Through 2011, DEF's Commission-approved DSM programs have achieved more than 5,000 GWh reductions in energy consumption and over 1,645 MW in demand savings, effectively eliminating the need for the Company to build and operate approximately eighteen (18) new peaking power plants. The elimination of the need to build additional generation plants has resulted in over $1.2 billion in customer energy savings.

Substantial reductions in energy consumption and demand already have been achieved by the Company in its service territory, necessarily resulting in diminishing future energy consumption and demand reductions from future energy efficiency programs and measures. It is simply more difficult to achieve additional reductions in energy consumption and demand, and more costly to do so too, with continued or new DSM programs. More simply put, DEF's past success with its DSM programs makes it more difficult to get more "bang for the buck" with new or revised DSM programs.

In addition, DEF's new DSM programs are competing with increasing gains in energy efficiency by measures implemented by customers themselves, either independently or as a result of other, non-utility incentives, such as building code changes for new customer construction. The Commission recognized this impact in its 2014 Florida Energy Efficiency and Conservation Act ("FEECA") report to the Florida Legislature, explaining to the Florida Legislature that such changes reduce the amount of incremental energy available to count toward utility savings through utility DSM programs. These impacts also make it more difficult and more costly to achieve each incremental increase in energy efficiency or demand reduction through DEF's DSM programs.

For all these reasons, as more fully explained by the Company in Docket No. 130200-EI, DEF's proposed DSM goals for the next ten years are lower than the Company's current DSM goals. As a result, the Company's proposed DSM goals have no impact on the Company's reliability need in 2016 and 2017. There simply are no cost-effective DSM measures or programs that can offset or defer the need for additional generation capacity beginning in 2016.

Q. Would the Company's reliability need in 2016 and 2017 be impacted if the results of the current DSM goals docket are different from what the Company expects them to be?

A. No. The Company firmly believes that its proposed DSM goals in Docket No.

130200-EI are reasonable, cost-effective goals for the Company and its customers, and that they will be accepted by the Commission. Even if the Commission for some reason departed from these proposed DSM goals, however, for several reasons the resulting goals would have no impact on the Company's reliability need in 2016 and 2017.

First, the future DSM goals will not even be established by Commission Order until the fall of 2014, at the earliest. The Company will then need time to evaluate, develop, and implement new or revise existing DSM programs and measures in an attempt to meet the new DSM goals. After these new or revised DSM programs and measures are implemented, there naturally will be a period of time before any results are observed in the Company's load and peak demand. The Company cannot obtain the new DSM goals, evaluate them, develop and implement new or revised DSM programs or measures to achieve those goals, and see the full results of these new or revised DSM programs or measures by the summers of 2016 and 2017 when the Company has a reliability need for new generation. Accordingly, even if the current DSM goals docket results in different, higher DSM goals for DEF than DEF has proposed in that docket, those DSM goals would have no impact on DEF's reliability need for additional generation capacity in the summer of 2016 and 2017.

Q. Are there other considerations in balancing demand- and supply-side resources?

A. Yes. The Company calculates its Reserve Margin based on the relationship between firm load and total capacity available to serve that load. Firm load represents firm customer load after all DSM capability is implemented. While dispatchable demand-side resources provide important and cost-effective resources to reduce load, they cannot be used as often or as long as physical generation without eventually affecting customer participation levels. Prolonged use of dispatchable DSM resources to meet customer load demand, especially in the summer months, will result in customer attrition in the dispatchable DSM program. Based on the Company's experience, when interruptions in customer service increase in frequency, customers are less willing to accept such service for lower rates. For this reason, DEF carefully evaluates increasing reliance on dispatchable DSM programs to meet load with additional physical reserves to meet that load. In the case of the Company's additional capacity needs in the summers of 2016 and 2017, based on projected load growth and the Company's existing and planned generation retirements, the planned addition of generation projects will increase the Company's share of physical reserves to approximately 54 percent of total reserve capacity (which includes DSM) in the summer of 2017. See Exhibit No. ___ (BMHB-5) to my direct testimony. This level of physical reserves, in the Company's view, is, at a minimum, necessary to maintain coverage of an unplanned outage of the fleet's largest unit or to maintain coverage in an extreme weather event.

Q. Were supply-side alternatives identified and considered to meet the Company's capacity needs commencing in 2016?

A. Yes, in fact, the Company's optimization of its resource plan to meet its capacity needs commencing in 2016 in its IRP process determined that supply-side generation alternatives were necessary to cost-effectively meet customer capacity needs beginning in this time period. DEF examined several alternative generation expansion plans to meet this need, however, the alternative generation expansion plans that could be evaluated were limited by the need to place generation in-service in 2016 and 2017. With this limitation in mind, the Company evaluated generation options to determine those options that were the most cost-effective, screening the options based on cost, fuel sources and availability, technological maturity, and overall resource feasibility within the Company's system.

Generation alternatives that passed this screen were included in the Company's economic evaluation in the EPM production cost computer model. The primary output of EPM is a Cumulative Present Value Revenue Requirements ("CPVRR") comparison of the generation resource options that satisfied DEF's reliability requirements. The most cost-effective supply-side resources were evaluated and ranked by system revenue requirements. The Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project had the lowest CPVRR and were chosen by the Company as its Base Generation Plan to meet the Company's reliability needs in 2016 and 2017.

Q. Did the Company consider supply resources from other generation suppliers in its planning process to meet its capacity needs commencing in 2016?

A. Yes. DEF always takes into account the potential future supply of firm capacity from purchased power contracts during the study period in its evaluation. In fact, DEF determined that a short-term power purchase agreement ("PPA") with Southern Company over the limited transmission import interface was cost effective and included this purchase in its Base Generation Plan to meet its generation capacity needs commencing in 2016. DEF also evaluated several, other PPAs, and even acquisitions of generation facilities, to determine if they were more cost effective, considering all price and non-price attributes, than the Company's self-build new generation Suwannee Simple Cycle and Hines Chillers Power Uprate Projects to meet the Company's capacity needs commencing in 2016. These other, potential generation alternatives, and the Company's evaluation of them, are discussed in more detail later in my direct testimony.

Q. Did the Company consider renewable energy sources and technologies to meet its capacity needs in 2016?

A. Yes. The Company evaluates the timelines for new technologies including renewable energy source and technologies on a continuing basis as part of its IRP process. The Company also has a Request for Renewables ("RFR") that continuously solicits proposals for renewable energy projects. The Company will continue to evaluate the development or purchase of renewable energy in the future to potentially reduce DEF's use of fossil fuels or to defer or eliminate the need to construct more conventional, fossil-fueled generation resources.

Q. Were renewable energy sources or technologies reasonably available to the Company to meet its capacity needs commencing in 2016?

A. No. No commercially available, economically feasible renewable generation resource currently exists to displace or defer DEF's generation capacity needs commencing in the summer of 2016. DEF has a contract with U.S. Ecogen for a 60 MW plant that will use an energy crop as a fuel source with a planned in-service date of January 2017, however, that in-service date is uncertain and, even if this plant achieves commercial operation in January 2017, it does not address DEF's generation capacity need commencing in the summer of 2016, and it does not defer the need for generation capacity in the summer of 2017. Additionally, no other proposal for renewable energy projects have been received in response to the Company's RFR that will displace or defer the Company's generation capacity needs in 2016 and 2017.

V. THE SUWANNEE SIMPLE CYCLE AND HINES CHILLERS POWER UPRATE PROJECTS.

Q. Please explain the Company's plan to meet its capacity needs commencing in 2016.

A. The Company's plan includes the Suwannee Simple Cycle Project in the summer of 2016 and the Hines Chillers Power Uprate Project by the summer of 2017. As

I mentioned above, the Company also executed a short term PPA with the Southern Company for generation capacity commencing in 2016 as part of its base generation plan with the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project. Both Company projects are necessary to meet the Company's summer Reserve Margin requirement in 2016 and 2017 to deliver reliable electric service to the Company's customers.

The Suwannee Simple Cycle Project consists of two F class combustion turbine generators, two generator step-up transformers, fuel oil and demineralized water storage tanks, and related balance of plant facilities installed by June 2016 at the Company's existing Suwannee power plant site in Suwannee County, Florida. The Suwannee power plant site has existing infrastructure to support the Suwannee Simple Cycle Project. The Suwannee plant site has existing gas- and oil-fired combustion turbines, steam units and a transmission switchyard among other facilities. The new F class combustion turbine generators will be connected via a gas lateral to the Florida Gas Transmission gas pipeline and to the existing site metering and regulating station. One combustion turbine will be connected to the existing 115 kv transmission switchyard and the other combustion turbine will be connected to the existing 230 kv transmission switchyard. This existing infrastructure at the Suwannee site reduces the cost of the Suwannee Simple Cycle project. The estimated cost of the Suwannee Simple Cycle project, including the Allowance for Funds Used during Construction ("AFUDC"), is $197 million. The Suwannee Simple Cycle Project is explained in more detail in the testimony of Mr. Landseidel in this proceeding.

The Hines Chillers Power Uprate Project involves the installation of a chiller system designed to cool gas turbine inlet air to 50 degrees F and, therefore, increase the summer capacity of the combustion turbines for all four existing power blocks at the HEC. The HEC contains four natural gas-fired combined cycle units or power blocks with approximately 1,900 MW of total installed capacity. The Hines Chillers Power Uprate Project is projected to increase the total HEC power block summer output by approximately 220 MW. The Hines Chillers Power Uprate Project involves the installation of chiller modules and a large chilled water storage tank, auxiliary power system, pumps and chilled water supply and return piping, and gas turbine air inlet chiller coils including modification of the air inlet ducts on the existing power blocks. The estimated cost of the Hines Chillers Power Uprate Project, including AFUDC, is $160 million. The Hines Chillers Power Uprate Project is also explained in more detail in Mr. Landseidel's testimony in this proceeding.

Q. What impact will the addition of the Suwannee Simple Cycle and Hines Chillers Power Uprate projects have upon DEF's Reserve Margin and its ability to provide reliable service to its customers?

A. As shown in Exhibit No. ___ (BMHB-4), the addition of the Suwannee Simple Cycle Project will increase DEF's summer peak Reserve Margin to 20.4 percent in the summer of 2016. The addition of the Hines Chillers Power Uprate Project by the following summer will increase DEF's 2017 summer peak Reserve Margin to 20.7 percent. See Exhibit No. ___ (BMHB-4). The Suwannee Simple Cycle and Hines Chillers Power Uprate Projects allow DEF to satisfy its commitment to maintain a minimum 20 percent Reserve Margin.

Q. Why did DEF select the Suwannee Simple Cycle and Hines Chillers Power Uprate Projects as the Company's generation options to meet its need in the summers of 2016 and 2017?

A. DEF's resource planning analyses show that the economics favor these projects over other Company generation options that were available to meet its near-term capacity needs in the summers of 2016 and 2017. The Company evaluated new generation, existing plant uprate projects, and existing generation life extension projects to meet this need. This evaluation included the fixed project capital costs, fixed and variable O&M costs, fuel and consumable costs, transmission costs, and the technical feasibility of these generation options. Based on this evaluation, the Suwannee Simple Cycle and Hines Chillers Power Uprate Projects were the most cost-effective generation options, based on price and non-price attributes, to meet the Company's reliability needs in the summers of 2016 and 2017. Exhibit No. ___ (BMHB-6) to my direct testimony shows the range of projects considered. I will note that at this point in the Company's evaluation, the Hines Chillers Power Uprate Project was considering chilling systems on only 3 of the 4 HEC power blocks (Power Blocks 2, 3, and 4). Further evaluation on Power Block 1 was centered around the thermal performance uprate ("TPU"). The TPU was not deemed to be economically favorable and was later dropped for consideration.

Q. What are the transmission impacts and benefits of the Suwannee Simple Cycle and Hines Chillers Power Uprate Projects?

A. There are no additional transmission costs associated with transmission enhancements or modifications for the Hines Chillers Power Uprate Project. These are power uprates to the existing HEC power blocks which are supported by the existing transmission system connecting the HEC to DEF's system. There are limited transmission system network upgrades and costs for the Suwannee Simple Cycle Project associated with the transmission interconnection of the combustion turbines at the existing Suwannee site. These are added customer benefits from installing these projects at existing power plant sites on the Company's system compared to generation at a Greenfield site. These transmission costs and benefits are also explained in the direct testimony of Mr. Ed Scott in this proceeding.

Q. Are there environmental benefits associated with the Suwannee Simple Cycle and Hines Chillers Power Uprate projects?

A. Yes. Both projects are located at existing brown field, power plant sites. Both projects have limited to no additional environmental impact at the existing sites. As a result, the Company is able to add over 500 MW of additional summer generation capacity by the summer of 2017 with little to no additional environmental impact. These projects provide the Company with the ability to substantially increase its summer generation capacity to meet customer energy demand while maintaining the Company's compliance with current and future environmental regulations.

VI. DEF'S GENERATION RESOURCE OPTIONS ASSESSMENT .

Q. Did DEF evaluate other supply-side alternatives to meet its generation needs in the summers of 2016 and 2017?

A. Yes. The Company evaluated PPAs from other utilities and non-utility generators and the acquisition of existing, non-utility generation plants in addition to the Company's self-build generation options. These are the same options that the Company said it was going to evaluate in the 2013 Settlement Agreement approved by the Commission.

Q. Please describe DEF's efforts to solicit proposals from other supply-side providers to meet its capacity needs commencing in the summer of 2016.

A. DEF first contacted other utilities and non-utility generators with the capability of supplying some or all of the Company's near-term capacity needs in September 2012. DEF issued a solicitation for proposals for PPAs. Bids were initially received in October 2012, evaluated in November 2012, and a short list was identified and negotiations over draft PPAs commenced in January and February 2013. Changes with the Company's resource plan, in particular with the decision to retire CR3 and the potential early retirement of CR1 and CR2 in this same time period, required the Company to re-evaluate its resource plan and its generation capacity needs. This re-evaluation led the Company to identify a potential near-term generation capacity need of up to 1,150 MW in the 2013 Settlement Agreement. At the same time, however, the Company was evaluating a plan to continue commercial operation of Crystal River South in compliance with MATS through site averaging for another two years. As I explained above, the Company ultimately determined that it could operate Crystal River South until 2018 under a MATS compliance plan and it has implemented that plan with Commission approval. The implementation of this plan to continue the operation of Crystal River South to 2018 substantially reduced the Company's summer generation capacity needs prior to 2018.

DEF requested renewed proposals for PPAs and solicited interest in potential generation facility acquisitions from the potential generation suppliers who responded to the Company's earlier RFP. These potential suppliers submitted renewed bids for PPAs and generation facility acquisition offers to meet DEF's near-term generation capacity needs in September and October 2013. The Company evaluated these proposals and followed up with the bidders regarding additional information, issues, and potential supplemental offers from October 2013 through February 2014.

Q. Please explain the supply-side proposals you received.

A. The Company invited alternative proposals that offered superior customer value to the Company's self-build generation options to meet the Company's near-term capacity needs prior to 2018. We sought reliable, dispatchable, and financially sound proposals that would provide the Company generation capacity by the summer of 2016 and/or the summer of 2017. We received nine proposals for PPAs or generation facility acquisitions from seven participants. We evaluated all of these proposals by systematically following a structured, orderly evaluation process that evaluated all proposals, including the Company's self-build generation projects, on price and non-price attributes.

After initial screening, DEF evaluated both generation facility acquisition and PPA proposals from two participants. There was one system PPA proposal from another investor-owned utility, two PPA proposals from non-utility generators and three additional generation facility acquisition proposals. A confidential chart of these supply-side generation proposals that were received and evaluated by the Company to meet its capacity needs commencing in the summer of 2016 is included in Exhibit No. ___ (BMHB-7) to my direct testimony.

Q. Please describe the evaluation process.

A. The evaluation process involved an analysis of the price and non-price attributes on all the supply-side generation proposals received and the Company's self-build generation options. The proposals were first segregated into categories distinguished by the type of proposal and term to ensure a consistent and fair evaluation by categorizing and evaluating "like type" proposals. Next, the Company conducted an economic evaluation of the proposals. In this step, the proposals were screened based on the fixed and variable payments or costs and economic optimization screening analyses were performed.

The Company also preliminarily evaluated the technical feasibility and viability of the proposed acquisitions through an analysis of such factors as the operating, maintenance, and physical conditions of the plants. Other non-price attributes, including insurance, project risk, environmental impacts and compliance, and regulatory feasibility, among other factors, were also considered. This preliminary qualitative assessment was undertaken to determine if there were any proposals that were such outliers from a qualitative risk perspective that further economic evaluation was unnecessary. Upon the completion of the economic evaluation, however, a more detailed qualitative evaluation was necessary, assuming that one or more proposals were economic, before the Company could conclude that a proposal was the most cost effective generation capacity option for DEF's customers.

Finally, the Company conducted a detailed economic evaluation of each proposal compared to DEF's self-build generation alternatives, the Suwannee Simple Cycle and the Hines Chillers Power Uprates projects. This detailed economic evaluation included all costs, including transmission cost impacts, in the analysis.

Q. How did the Company perform the detailed economic evaluation?

A. The Company performed a detailed economic optimization analysis of the alternative and Company supply-side generation proposals to meet its capacity needs beginning in the summer of 2016. The purpose of the optimization analysis was to develop an optimal resource plan for each proposal for the detailed economic analysis. The optimization analyses were performed for a period of thirty years to capture all costs associated with each proposal and, in particular, to determine the type of units that make up the optimal resource plan including a proposal.

The optimization analysis was performed using the Strategist optimization model. While the economic screening analysis compared the proposals to each other based simply on the cost of the proposals in isolation, the optimization analyses assessed the impact of each proposal on total system costs and compared those costs to the costs of the Company's base case self-build generation plan. The optimization analysis, therefore, shows the net impact of both the proposal cost and the impact the proposal has on system capital revenue requirements and fixed and operating costs. Such an analysis explicitly examines the relative impacts on system costs for fuel and variable O&M of the other units on DEF's system and any impact on DEF's purchased power costs. DEF integrates the resource plan optimization and fixed cost results including capital revenue requirements for generation and transmission from Strategist with the detailed production cost results from the EPM model in its detailed economic evaluations.

Q. What was the Company's base case generation plan in its detailed economic evaluation?

A. The base case was the Suwannee Simple Cycle and Hines Chillers Power Uprate projects in the summers of 2016, and 2017, respectively, followed by the other planned generation units included in the Company's 2014 TYSP. The base case or "self-build" option included chillers at only three Hines power blocks at this stage of the analysis. See Exhibit No. ___ (BMHB-2).

Q. Please explain what the Strategist optimization model is and what it does.

A. The Strategist optimization model is an industry-recognized utility system production cost model that we use to develop optimal resource plans. Strategist is a detailed, chronological production costing model that simulates each generating resource on the DEF system, both existing and future, and how each resource is used to serve the forecasted peak demand and energy requirements of DEF's customers. The objective function of the Strategist model is to minimize the cumulative present value of revenue requirements ("CPVRR") for the DEF generation system, subject to the 20 percent Reserve Margin constraint.

Thus, for each resource proposal evaluated, the Strategist model provides the optimal generation expansion plan for the 30-year study period, if the proposed resource was selected. Inputs to the model include the load and energy forecast and the costs and characteristics (such as heat rates, outage rates, and maintenance requirements) of the Company's existing generating units and purchase power agreements. Costs and operating characteristics of potential future supply-side resources, which could be generating units or purchases, are also included in the model. Strategist model runs develop alternative resource plans to meet the projected future customer requirements using all possible combinations of resources, and it calculates the CPVRR for each combination. The model then sorts each alternative from lowest to highest cost. From an economics-only perspective, the lowest cost plan is the optimal plan.

Q. How were the results of the Strategist model optimization analysis used?

A. The results of the Strategist optimization cost analyses were used to identify optimal resource plans corresponding to each of the proposals or self-build options selected for evaluation. DEF reviewed the best plans produced by Strategist for each option and selected the plan with the lowest CPVRR for each that was feasible given constraints of transmission, construction, permitting, and other factors. The fixed cost output from Strategist was then incorporated into the financial analysis of each alternative proposal.

Q. How were the production costs associated with each alternative proposal determined?

A. After using Strategist to identify the lowest cost plan candidates, DEF uses the Planning and Risk module of the Energy Portfolio Manager ("EPM") software to further evaluate the production cost results. EPM is a detailed production cost model which evaluates the fleet dispatch in each hour over the period of the study taking into consideration both costs and projected operating constraints such as unit start times, minimum up and down times, reliability must run requirements, and projections of planned and unplanned outages. The analysis must capture these costs because each alternative proposal, due to, for example, its size, heat rate (if relevant), proposed pricing, and other factors, causes the other resources on the DEF generation system to operate in a different manner, resulting in different total system production costs. Production cost results from EPM were combined with fixed cost calculations from Strategist to calculate total 30-year production costs for each proposal and a resulting CPVRR for each proposal alternative. The cost results and CPVRR for each proposal is reviewed individually and then compared to the self build case.

Q. Were any other cost impacts included in the analysis?

A. Yes. The fixed costs of the alternatives, that is, the fixed charges of the proposals and the construction costs and fixed O&M costs of the Company's self-build generation projects, were captured in the financial analysis. The transmission construction costs to integrate each of the proposals and the Company's self-build generation projects into the transmission system were also included in the detailed economic analysis. The annual cash flow pattern of these transmission construction costs was based on typical expenditure patterns. All these costs were captured in the Strategist modeling analysis. Finally, we also evaluated the cost of imputed debt by determining the additional equity cost related to the purchased power proposals. The cost of imputed debt is typically applied to PPA proposals to ensure that the total costs of the PPA proposals include the marginal impact of the fixed future commitment on DEF's capital structure. This additional cost is the direct result of incurring fixed future payment obligations. The cost of imputed debt is a real cost associated with a PPA proposal and it therefore needs to be considered by the utility in determining the most cost-effective resource to meet its customers' reliability needs. In this case, because the term of the PPAs evaluated was five years or less, the impact of the imputed debt was found to be less than $5 million and was deemed to be not material in the results.

Q. What were the results of the detailed economic analysis?

A. In CPVRR terms, the Company's base generation plan --- the Suwannee Simple Cycle and Hines Chillers Power Uprate projects --- was found to be less expensive or more cost effective than all of the PPA proposals and all but one of the potential generation facility acquisition proposals. The Company's base generation plan was only marginally more expensive than one of the acquisition proposals, but in CPVRR terms over the 30-year study period they were nearly equivalent on an economic basis to the Company. Another potential generation facility acquisition proposal ranked third behind this generation facility acquisition and the Company's base generation plan by almost $200 million. Exhibit No. ___ (BMHB-8) to my direct testimony show the results of the initial detailed economic analysis.

Q. Did DEF consider combining one of the self-build projects with the alternative proposals?

A. Yes. DEF tested the proposals with and without the Hines Chillers. Initially, this was because some of the proposals (e.g. Acquisitions 4 and 5) did not supply sufficient MWs to meet DEF's need. During the course of testing alternatives, DEF modeled several of the proposals with and without the Hines Chillers. In each case, addition of the Hines Chillers made the project more favorable from a

CPVRR perspective, even when the capacity of the Chillers was not required to meet the reserve margin. As a result, all of the resource plans represented in Exhibit No. __ (BMBH-8) include inlet chilling on three Hines Power Blocks.

Q. What was DEF's next step in the analysis?

A. Following review of the initial detailed economic results, DEF quantified a number of sensitivity risks around the proposals evaluated. Included in these risks were construction cost sensitivity around the Suwannee and Hines projects, gas transportation contract risks, plant condition and maintenance risks, and transmission cost risks. Exhibit No. ___ (BMHB-9) shows the results of the cost risk sensitivity analysis.

Given the range of values, DEF looked closely at two acquisition proposals as alternatives to the DEF self-build project. These were Acquisitions 1 and 2. In the case of Acquisition 1, while the option had an apparently positive CPVRR relative to the self-build option, DEF recognized that there were a number of costs that might not be fully developed. Chief among these undeveloped costs was the fact that the option had been evaluated based on its existing fuel purchase arrangements. DEF recognized that these existing arrangements provided less firm gas transportation than would be typical for a DEF facility of this type. While this might be suitable for an Independent Power Producer like Acquisition 1, further evaluation would be warranted to determine if this would provide adequate reliability for a utility asset.

In the case of Acquisition 2, DEF had made conservative assumptions regarding the cost of transmission upgrades required to deliver the power from Acquisition 2 to DEF. DEF recognized that further analysis might yield a lower cost solution. For this reason, DEF looked more closely at Acquisition 2. However, in all the acquisition cases, DEF recognized the risk that due diligence might identify differences in maintenance practices, spares stocking, or issues around unit condition, among other factors, that would add cost to these acquisition alternatives. Based on the results of these initial economic analyses, DEF concluded that there was potential for two of the acquisitions to be competitive to the self-build and that it would be prudent to proceed with an evaluation of the FERC market screen risks associated with the two acquisitions before concluding the economic analysis and proceeding to the due diligence evaluation of the potential acquisition options.

Q. What additional analyses with respect to these proposals did DEF perform?

A. Because the cost sensitivities showed that two generation facility acquisition proposals had the possibility of being close in the CPVRR analyses to the Company's base generation plan the Company took the next step in determining the feasibility of any proposed generation facility acquisition by conducting a Federal Energy Regulatory Commission ("FERC") market screen analysis.

The FERC market screen analysis is a required step in obtaining FERC approval under section 203 of the Federal Power Act ("FPA") for any public utility acquisitions of jurisdictional generation facilities. Pursuant to FPA section 203, the FERC must determine that a public utility generation facility acquisition transaction is in the public interest. To make this determination, FERC reviews the proposed transaction to assess its effect on competition in the wholesale market, wholesale rates, and regulation. The FERC market screen, or Competitive Analysis Screen, is part of this review under the Antitrust Agencies' Horizontal Merger Guidelines adopted by FERC. FERC must approve any potential generation facility acquisition by the Company before the Company can complete that acquisition.

Q. How did the Company assess the competitive impact of its proposed generation facility acquisition under the FERC market screen test?

A. The Company retained Julie Solomon with Navigant Consulting, Inc. to perform the FERC market screen analysis. Julie Solomon and Navigant are well-recognized industry experts in this area. Julie Solomon has performed the FERC market screen analysis dozens of times for potential mergers or generation facility acquisitions and she has filed testimony many times at FERC regarding the implementation and application of the FERC market screen to such transactions.

Q. What were the results of the FERC market screen analysis?

A. Both potential generation facility acquisitions that were evaluated failed the FERC Competitive Analysis Screen. Failure of the FERC Competitive Analysis Screen means that FERC likely will not approve the generation facility acquisition transaction without mitigation efforts by the Company to eliminate the screen failures. The FERC market screen analysis and the results of that analysis are explained in more detail in the direct testimony of Julie Solomon filed on the Company's behalf in this proceeding.

Q. What did the Company do with the FERC market screen analysis results?

A. The Company decided, based on these results, that the potential generation facility acquisitions were not cost effective for the Company's customers and should not be considered further by the Company. The Company determined that the Company's base generation plan was the most cost-effective resource plan to meet customer reliability needs in the summers of 2016 and 2017.

Q. Why did the Company make this decision?

A. Both potential generation facility acquisitions failed the FERC Competitive Analysis Screen. As explained by Julie Solomon in her testimony, failure of the FERC Competitive Analysis Screen means that FERC likely will not approve the generation facility acquisition without structural mitigation to mitigate the screen failures. There are two potential FERC-approved mitigation measures. One is for the Company to sell its own generation facilities to reduce DEF's owned or controlled generation capacity in the market. This mitigation measure makes no sense for the Company. DEF cannot sell off generation because DEF needs additional generation capacity to provide reliable electric service to its customers. This remedy is not a reasonable mitigation measure for the Company.

Another FERC-approved mitigation measure is adding transmission import capability to reduce DEF's share of the generation capacity in the market by increasing the total supply of generation in the market. This means the Company must build additional transmission facilities to expand the transmission import capability. The Company cannot rely on currently planned transmission system facility upgrades for this mitigation. The additional transmission must be net new facilities to the DEF system.

Increasing the transmission import capability by building net new transmission facilities is not a reasonable mitigation measure to eliminate the screen failures for these potential generation facility acquisitions. As explained by Julie Solomon in her direct testimony, a range of 600 MW to 800 MW of additional transmission import capacity must be added to DEF's system to mitigate the FERC screen failures for the lowest cost potential generation facility acquisition, and a minimum of 1,000 MW of additional transmission import capacity must be added to DEF's system for the other generation facility acquisition to mitigate its FERC screen failures. Based on our experience with our transmission system and the costs to add transmission facility upgrades, the transmission system facility upgrades -- and the cost of the upgrades -- to provide an additional 600 MW to 800 MW of transmission import capacity would be substantial, in the realm of hundreds of millions of dollars, and, therefore, easily far in excess of any benefits that the potential generation facility acquisitions provide DEF's customers.

The best generation facility acquisition proposal was only marginally more cost-effective on a CPVRR basis over the ~~20-year~~ 30 year study period than the Company's self-build base generation plan. This marginal benefit does not warrant hundreds of millions of dollars in transmission system facility upgrades that DEF and its customers must incur to mitigate the FERC screen failures for this potential acquisition. The other potential generation facility acquisition evaluated under the FERC market screen analysis was already almost $200 million less cost-effective on a CPVRR basis than the Company's self-build generation plan, largely due to transmission system upgrades already required to incorporate the generation facility into DEF's system. The additional transmission system facility upgrades to provide a minimum of 1,000 MW of additional transmission import capability to mitigate the FERC screen failures for this potential generation facility acquisition clearly render this acquisition uneconomic for DEF and its customers.

Q. Were there any other factors that led the Company to determine that pursuit of FERC approval for these potential generation facility acquisitions was not in the best interest of the Company's customers?

A. Yes. Apart from the quantitative factors that render the potential generation facility acquisitions uneconomic, they are also qualitatively not the most cost effective options for DEF and its customers. DEF must still seek FERC approval for the generation facility acquisitions even if DEF elected to pursue mitigation, which as I explained above, is not an economically viable option for the Company. At a minimum, this means the Company must incur the cost and spend the time necessary to retain experts and develop the analyses for the case for FERC approval, and then initiate the FERC proceeding to obtain that approval, which is uncertain. The FERC proceeding, at a minimum, will take six months before the Company obtains a FERC decision. This is unacceptable to DEF and its customers. Setting aside the cost of the expert analyses and the FERC proceeding itself and the uncertainty of the outcome of that proceeding, DEF must make investment decisions now to ensure that it can reliably provide its customers with additional generation capacity in 2016.

Qualitatively too, there were other risks associated with these potential generation facility acquisitions that likely would have rendered them not cost-effective for DEF and its customers. DEF deployed a step-wise approach and evaluated these generation facility acquisitions first on the bases of CPVRR and FERC market screen analyses. Until DEF determined: (1) whether a potential acquisition was economically competitive; and (2) whether or not a potential acquisition could pass the FERC market screen, it did not make sense for DEF to complete its due diligence on these plant acquisitions, or engage in negotiations over the terms of the plant acquisitions. The condition of the plants; the environmental conditions of the plant sites; plant performance history, warranties and guarantees; financial guarantees; insurance and indemnity obligations, among other factors, would be fully evaluated only if the potential acquisition was shown to be economically competitive and capable of passing the FERC market screens. These additional qualitative factors, however, represent additional, unmitigated risk associated with the potential generation facility acquisitions that preclude the Company from determining that they are cost effective for customers.

As a result of the Company's economic and FERC market screen analyses and its evaluation of the qualitative risks associated with the proposed generation facility acquisitions, the Company determined that further review of the generation facility acquisition proposals was unnecessary. The most cost effective generation option to meet customer reliability needs prior to 2018 is the Company's self-build generation plan.

Q. Did you perform additional economic analyses following the results of the FERC market screen?

A. Yes. DEF updated the results of the most favorable remaining alternatives, adjusting the modeling case to the latest assumptions consistent with the 2014 TYSP. While this did not have a significant effect on the results, the results are shown in Exhibit __ (BMBH-10). This exhibit shows the difference in total system CPVRR associated with each supply-side generation alternative proposal compared to the Company's Base Generation Plan. DEF evaluated the highest ranking of the PPA options from the previous review and the remaining PPA-acquisition hybrid that DEF believed would pass the market screen. Both of these were significantly less cost effective than the self-build option. Prior to this point, all analyses had been done assuming that the chillers would be added only to Power Blocks 2, 3, and 4 at HEC. During this period, DEF engineering had concluded that it would be feasible to extend the chiller project to Power Block 1. The results in Exhibit __ (BMHB-10) continue to use the Suwannee project along with the three inlet chillers as the base case, but also shows the evaluation of the project with four chillers, and a resource plan in which the chillers were omitted and replaced by a third combustion turbine at Suwannee in addition to the comparison with the remaining PPA alternatives. These results support the conclusion that the most cost effective plan is the construction of the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project at all four Hines power blocks.

Q. Did you perform any sensitivity analyses?

A. Yes. DEF performed sensitivity analyses of the final alternatives in our High Gas Price sensitivity case and with no CO_2 price. These cases are typically run to establish the robustness of a conclusion and to indicate how the results will vary based on variation in fuel and emission pricing, typically two of the most sensitive inputs to the production cost model. The results of these analyses are shown in Exhibit __ (BMHB-11). Comparison of the results follow generally expected patterns, favoring portfolios with higher proportions of combined cycle in the high gas case and the reverse in the no CO2 case. Since the alternatives are all gas fired, the variations between cases are relatively small. The results of these sensitivity analyses support the conclusion that the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project together form the most cost effective selection for DEF's need in 2016, 2017, and beyond.

VII. THE MOST COST-EFFECTIVE GENERATION ALTERNATIVE.

Q. Is the Company's base generation plan the most cost-effective alternative for meeting the Company's reliability needs in the summers of 2016 and 2017?

A. Yes, it is. The Company conducted a careful screening of various other supply-side alternatives as part of its IRP process before identifying the Suwannee Simple Cycle and Hines Chillers Power Uprate projects as its base generation plan to meet its reliability needs by the summers of 2016 and 2017. Further, through the Company's evaluation of market proposals for alternative generation, the Company determined that the Suwannee Simple Cycle and Hines Chillers Power Uprate projects were more cost-effective, on a quantitative and qualitative basis, than any of alternative supply-side generation proposal on the market.

Q. What caused the Company's Base Generation Plan to be more cost effective than any of the other alternatives?

A. The Suwannee Simple Cycle Project is a new, state-of-the-art combustion turbine plant with higher fuel efficiency than existing combustion turbine PPAs or the acquisition of existing combustion generation facilities. As I explained above and as explained in more detail in the direct testimony of Mr. Landseidel, there are also economic benefits associated with its location at an existing Company power plant site. Further, there are no FERC market screen issues with new generation in the market. FERC is concerned with removing generation or the ability to remove generation from the market. For all these reasons, the Suwannee Simple Cycle Project proved to be a cost-effective part of the Company's base generation plan to meet its reliability needs in 2016.

The Hines Chillers Power Uprate Project is the most cost-effective generation option in every generation alternative scenario. This project adds summer generation capacity with additional combined cycle power generation. As a result, the Company obtains additional summer peaking generation at combined cycle generation efficiency and cost. The fuel efficiency and relatively low cost of the Hines Chillers Power Uprate project make it a highly cost-effective generation option to meet DEF's customer reliability needs.

VIII. CONSEQUENCES OF DELAY

Q. What will be the impact of delaying implementation of the Suwannee Simple Cycle and the Hines Chillers Power Uprate projects?

A. If the Suwannee Simple Cycle and Hines Chillers Power Uprate projects are delayed, DEF would not be able to satisfy its minimum 20 percent Reserve Margin planning criterion by the summer of 2016 and 2017, respectively, in the most reliable and cost-effective manner. This would expose DEF's customers to a risk of interruption of service in the event of unanticipated forced outages or other contingencies for which DEF maintains reserves. Even without an interruption in service, without the Suwannee Simple Cycle and Hines Chillers Power Uprate projects, DEF would be forced to enter into more costly PPAs to meet this near-term reliability need. As a result, DEF's customers would be subject to higher costs to serve their reliability needs in the summer of 2016 and 2017.

IX. CONCLUSION

Q. Please summarize the benefits of the Suwannee Simple Cycle and the Hines Chillers Power Uprate projects.

A. DEF needs the Suwannee Simple Cycle and Hines Chillers Power Uprate Projects to maintain its electric system reliability and integrity and to provide its customers with adequate electricity at a reasonable cost. By building these projects the Company will be able to meet its commitment to maintain a 20 percent Reserve Margin, and it will do so by improving not just the quantity, but also preserving the quality of its total reserves, maintaining an appropriate portion of physical generating assets in the Company's overall resource mix. The Company has exhausted conservation measures reasonably available to the Company and there are no reasonably available renewable energy resources or technologies to meet the Company's near-term reliability needs in the summers of 206 and 2017. The Suwannee Simple Cycle and Hines Chillers Power Uprate Projects are the most cost-effective resources to meet customer reliability needs in this time period. We, accordingly, request that the Commission approve the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project as the most cost-effective alternatives to meet the Company's need in 2016 and 2017.

Q. Does this conclude your testimony?

A. Yes, it does.

IN RE: PETITION FOR DETERMINATION OF COST EFFECTIVE GENERATION ALTERNATIVE TO MEET NEED PRIOR TO 2018 FOR DUKE ENERGY FLORIDA, INC.

BY DUKE ENERGY FLORIDA

FPSC DOCKET NO. 140111-EI

REBUTTAL TESTIMONY OF BENJAMIN M.H. BORSCH

I. INTRODUCTION AND PURPOSE OF REBUTTAL TESTIMONY.

Q. Please state your name and business address.

A. My name is Benjamin M.H. Borsch and I am employed by Duke Energy Corporation. My business address is 299 1st Avenue North, St. Petersburg, Florida.

Q. What is your position with Duke Energy?

A. I am the Director, IRP & Analytics --- Florida. In this role I am responsible for resource planning for Duke Energy Florida, Inc. ("DEF" or the "Company"). In my capacity as Director, IRP & Analytics --- Florida I was responsible for the Company's Integrated Resource Planning ("IRP") process that identified DEF's need for reliable generation capacity prior to 2018 and that led to the selection of the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project as the most cost effective generation alternative to meet DEF's need prior to 2018.

Q. Have you previously filed direct testimony in this Docket?

A. Yes. I filed direct testimony and exhibits on May 27, 2014 in support of the Company's Petition for Determination of Cost Effective Generation Alternative to Meet Need Prior to 2018 for Duke Energy Florida, Inc.

Q. Have any intervenors filed direct testimony in this docket?

A. Yes. Calpine Construction Finance Company, L. P. ("Calpine") and NRG Florida LP ("NRG") have intervened and filed direct testimony in this Docket. Calpine filed on its behalf in this Docket the direct testimony of Todd Thornton, John Simpson, Paul Hibbard, and Dr. David Hunger. NRG filed on its behalf in this Docket the direct testimony of Jeffry Pollock, Jim Dauer, and Dr. John Morris.

Q. Have you reviewed the direct testimony filed by Calpine and NRG in this Docket?

A. Yes. I reviewed the direct testimony and exhibits filed by both Calpine and NRG in this Docket. NRG filed the exact same direct testimony and exhibits in this Docket that NRG filed in Docket No. 140110-EI, which is the proceeding addressing the Company's Petition for Determination of Need for the Citrus County Combined Cycle Power Plant. Calpine also filed the exact same direct testimony and exhibits for witnesses Mr. Simpson and Mr. Hibbard in this Docket that Calpine filed in Docket No. 140110-EI, and Calpine filed slightly different direct testimony in this Docket for Calpine witness Mr. Thornton than what Calpine filed for Mr. Thornton in Docket No. 140110-EI. My rebuttal testimony in Docket No. 140110-EI addresses the direct testimony and exhibits filed by the Calpine and NRG witnesses in that Docket. The purpose of this rebuttal testimony is to respond to the direct testimony, exhibits, and recommendations of the Calpine and NRG witnesses in this Docket.

II. ORGANIZATION AND SUMMARY OF REBUTTAL TESTIMONY.

Q. How is your rebuttal testimony organized?

A. The first part of my rebuttal testimony in this Docket addresses Calpine's and NRG's new and different proposals to meet DEF's customer needs for generation capacity prior to 2018. To explain briefly, the Calpine witnesses rely in their direct testimony on a proposal to meet DEF's need prior to 2018 that was submitted to DEF after DEF filed its direct testimony and exhibits in this Docket. This proposal is different from the Calpine proposal that was submitted to and evaluated by DEF, and that is discussed in my direct testimony and exhibits in this Docket. NRG likewise submitted a new and slightly different proposal from the proposal that was submitted to, evaluated by, and addressed by DEF in my direct testimony and exhibits, but it is not clear from NRG's testimony which proposal NRG is now relying on in its direct testimony and exhibits in this Docket. In any event, the first part of my rebuttal testimony explains the history behind why Calpine and NRG made these different, alternative proposals, the discussions between the parties related to these and other proposals made to DEF after DEF filed its Petition, direct testimony, and exhibits in this Docket, and DEF's evaluation of these different, alternative proposals that demonstrates that, despite NRG's and in particular Calpine's efforts to close the gap between their initial proposals and DEF's Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project, their revised proposals, on a quantitative and qualitative basis, still are not the most cost effective generation alternative to meet DEF customer needs prior to 2018.

Q. How is the rest of your rebuttal testimony organized?

A. I will also address the evidence presented by DEF in support of its Petition in this Docket that is uncontested by any witness, and the evidence that is not disputed by any Calpine or NRG witness, respectively. I believe this discussion of the uncontested DEF evidence is helpful in focusing the Commission on the issues that are really in dispute in this Docket.

Next, I will address the Calpine and NRG witness criticisms about DEF's quantitative and qualitative evaluation of the most cost effective generation alternative to meet DEF's need prior to 2018. This includes their criticisms regarding the evaluation methodology and the quantitative and qualitative factors that DEF considered in that evaluation, including firm natural gas transportation reliability and costs, transmission reliability and costs, and the Federal Energy Regulatory Commission ("FERC") Competitive Analysis Screen. DEF witnesses Jeff Patton and Ed Scott have also filed rebuttal testimony addressing the intervenors' criticisms of DEF's quantitative and qualitative assessment of firm natural gas transportation and transmission reliability and costs, respectively, in DEF's evaluation of the most cost effective alternative to meet DEF's need prior to 2018. In addition, Julie Solomon with Navigant Consulting, Inc. has filed rebuttal testimony addressing the NRG and Calpine direct testimony about the FERC Competitive Analysis Screen.

Finally, I will summarize the quantitative and qualitative benefits to DEF's customers of the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project compared to the Calpine and NRG alternative generation capacity proposals. Simply put, considering all quantitative and qualitative factors, the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project are the most cost effective generation alternative to meet DEF's customer needs prior to 2018.

Q. Please provide a brief summary of your rebuttal testimony.

A. DEF needs the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project by the summer of 2016 and 2017, respectively to meet its 20 percent Reserve Margin commitment to provide its customers reliable, cost-effective power. No conservation measures or renewable resources exist in this time frame to replace or mitigate this need. NRG and Calpine do not dispute the Company's reliability need for generation capacity prior to 2018, rather, they argue the Company should have selected their generation capacity proposals, rather than the Suwannee Simple Cycle Project, to meet the Company's need.

NRG and Calpine do not challenge the cost-effectiveness of the Hines Chillers Power Uprate Project to meet DEF's reliability need in the summer of 2017. No NRG or Calpine witness directly challenges DEF's testimony that the Hines Chillers Power Uprate Project is a cost-effective generation capacity resource for DEF's customers.

NRG witnesses Mr. Pollock and Mr. Dauer claim the NRG plant acquisition proposal – Acquisition 1 – that NRG submitted in response to DEF's request for proposals to meet DEF's need prior to 2018 is more cost effective than the Suwannee Simple Cycle Project based on DEF's <u>initial</u> economic evaluation. NRG ignores the results of DEF's <u>continued</u> quantitative and qualitative evaluation of that proposal that demonstrates the NRG plant acquisition proposal is not more cost effective than the Company's self-build generation projects --- even though Mr. Pollock concedes that DEF must consider quantitative and qualitative factors and should not base its decision on the results of an initial economic analysis. Mr. Pollock and Mr. Dauer ignore the results of DEF's complete evaluation of NRG's proposal because they know the firm gas transportation requirements that DEF requires to rely on the NRG plant as a firm resource to meet DEF's load-serving obligation renders the NRG acquisition proposal uneconomic. Mr. Dauer's claimed ability to operate the NRG plant on non-firm and "spot" market gas transportation arrangements in the past as an Independent Power Producer is not a substitute for DEF's obligations to provide firm power to customers at all times. Further, no NRG witness disputes the fact that the NRG Acquisition 1 proposal failed the FERC Competitive Analysis Screen rendering FERC approval of the NRG plant acquisition unlikely without substantial mitigation. For all these reasons, the Suwannee Simple Cycle Project remains a superior generation capacity resource to the NRG plant acquisition proposal that NRG continues to advance in their testimony to meet DEF's need prior to 2018.

Calpine does not rely on its initial plant acquisition or power purchase agreement ("PPA") proposal in the direct testimony of its witnesses, rather, Calpine relies on the last of its final and best offers that Calpine submitted to DEF after DEF filed its Petition in this Docket. Calpine's final and best offers moved closer to the cost effectiveness of the Suwannee Simple Cycle Project, but they still were not more cost effective than the Company's self-build generation projects to meet DEF's need prior to 2018. Calpine's primary expert witness Mr. Hibbard disputes this determination, but he fails to include all the costs associated with Calpine's final and best offer in his evaluation. To illustrate, he ignores additional transmission wheeling charges that either he or Calpine witness Mr. Simpson acknowledge exist because of the Calpine final and best offer. Mr. Hibbard also ignores qualitative risks associated with Calpine's final and best offer that present additional cost risk to DEF's customers. When all costs are included, and the qualitative cost risks accounted for in the evaluation, the Calpine final and best offer is not a superior generation capacity resource to the Company's self-build generation projects to meet DEF's need prior to 2018.

Calpine's witness Mr. Hibbard also criticizes DEF's evaluation methodology. However, he deliberately ignores or does not understand DEF's evaluation models and tools, criticizes DEF for not employing production cost economic dispatch models that DEF in fact employed, and urges the Commission instead to use his results from a simplistic screening tool for "like type" resources to evaluate different types of resources without understanding the costs and benefits of the dispatch of the resources on DEF's system. His "evaluation" is not a detailed economic analysis of the proposals or a fair and accurate criticism of DEF's detailed evaluation of the alternative generation capacity resource options to meet DEF's reliability need prior to 2018. DEF's detailed evaluation -- which includes an analysis of the economic dispatch of the alternative resources on DEF's system using the very model Mr. Hibbard said DEF should use --- demonstrates that DEF has a need for peaking generation capacity commencing in the summer of 2016 and that the Suwannee Simple Cycle Project is the most cost effective generation capacity resource to meet that need. Even the simplistic screening tool Mr. Hibbard used in his "evaluation" demonstrates that, if peaking generation capacity is needed --- which is the case beginning in the summer of 2016 --- the Suwannee Simple Cycle Project is more cost-effective than the Calpine plant under any Calpine proposal that DEF has received to meet DEF's need.

As a result, the Company decided that, based on the FERC market screen results and the results of its own detailed economic and qualitative analyses, the potential plant acquisitions under the Calpine and NRG initial or final and best offer proposals are not cost effective for the Company's customers. The Company determined that the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project are more cost-effective, on a quantitative and qualitative basis, than any of the alternative supply-side generation proposals. DEF requests Commission approval of the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project as the most cost effective generation capacity resources to meet DEF's need for generation capacity prior to 2018.

Q. Do you have any exhibits to your rebuttal testimony?

A. Yes, I am sponsoring the following exhibits to my rebuttal testimony:

- Exhibit No. ___ (BMHB-12), a composite exhibit of the written communications between DEF and NRG between late May 2014 and early July 2014;
- Exhibit No. ___ (BMHB-13), a composite exhibit of the written communications between DEF and Calpine between late May 2014 and early July 2014;
- Exhibit No. ___ (BMHB-14), NRG's final and best offer to sell its plant to DEF;
- Exhibit No. ___ (BMHB-15), DEF's evaluation of NRG's final and best offer to sell its plant to DEF;
- Exhibit No. ___ (BMHB-16), Calpine's June 16, 2014 final and best offer to sell its plant to DEF;
- Exhibit No. ___(BMHB-17), Calpine's July 3, 2014 final and best offer to sell its plant to DEF;

- Exhibit No. ___ (BMHB-18), DEF's evaluation of Calpine's July 3, 2014 final and best offer to sell its plant to DEF;
- Exhibit No. ___ (BMHB-19), DEF's summary of similar capital projects to the Suwannee Simple Cycle Project; and
- Exhibit No. ___ (BMHB-20), DEF's load forecasts.

These exhibits were prepared by the Company at my direction and under my control and they are true and correct.

III. THE CALPINE AND NRG CONTINUING PROPOSALS AND FINAL DEF EVALUATION OF THEIR PROPOSALS TO DETERMINE THE MOST COST EFFECTIVE GENERATION ALTERNATIVE TO MEET DEF'S NEED PRIOR TO 2018.

A. NRG AND CALPINE INITIAL GENERATION CAPACITY PROPOSALS.

Q. Did Calpine and NRG submit proposals to meet DEF's need prior to 2018?

A. Yes. As I explained in my direct testimony and as Calpine witness Mr. Thornton correctly notes in his direct testimony, DEF originally issued a solicitation for PPA proposals to meet its need for generation capacity in the 2016-2019 time frame in mid-September 2012. (Borsch Direct Testimony ("Test."), pp. 32-33; Thornton Direct Test., p. 6, lines 4-7). Both Calpine and NRG submitted PPA proposals in response to this solicitation. DEF selected both the Calpine and the NRG PPA proposals for further negotiation, but did not complete any agreement on PPA terms with either NRG or Calpine in the first quarter of 2013. The primary reason DEF suspended the negotiations for a PPA with NRG and Calpine is that DEF's need for generation capacity was changing in this time period. (Borsch Direct Test., pp. 32-33).

DEF decided to retire its Crystal River Unit 3 ("CR3") nuclear power plant in February 2013. In 2013, the Company also was evaluating the retirement of its Crystal River Unit 1 ("CR1") and Crystal River Unit 2 ("CR2") coal-fired steam generation units as early as 2015 as a result of the United States Environmental Protection Agency ("EPA") Mercury and Air Toxics Standard ("MATS") Clean Air Act regulations. These impacts are discussed in more detail in my direct testimony (Borsch Direct Test., pp. 7-10), but as a result of the CR3 retirement and the potential CR1 and CR2 retirements, as well as DEF's projected load growth, DEF identified a need up to 1,150 MegaWatt ("MW") prior to 2018. This potential need prior to 2018 was identified in the Company's Revised and Restated Settlement Agreement ("2013 Settlement Agreement") approved by the Florida Public Service Commission ("FPSC" or the "Commission") in Order No. PSC-13-0598-FOF-EI. (Borsch Direct Test., p. 11).

DEF determined that DEF could reduce this need prior to 2018 by completing projects at CR1 and CR2 and employing site emission averaging at the Crystal River Energy Complex ("CREC") to comply with MATS and extend the operation of CR1 and CR2 to 2018. This plan was presented as a modification to the Company's Integrated Clean Air Compliance Plan to the Commission in December 2013 and approved by the Commission in Order No. PSC-14-0173-PAA-EI (consummating Order No. PSC-14-0218-CO-EI issued May 9, 2014). (Borsch Direct Test., pp. 8-9). As a result of this plan for the continued operation of CR1 and CR2 beyond 2016, the Company reduced its generation capacity need prior to 2018 from 1,150MW to about 470MW. (Borsch Direct Test., p. 11, lines 14-23).

Q. What happened after DEF reduced its generation capacity needs prior to 2018 with its MATS compliance plan for the continued operation of CR1 and CR2 beyond 2016?

A. In September 2013 DEF requested the respondents to DEF's earlier PPA solicitation in 2012 to submit revised proposals to DEF to meet its revised generation capacity need prior to 2018. NRG and Calpine, among others, submitted revised generation capacity proposals to meet DEF's need prior to 2018 in the fall of 2013. These supply-side proposals are described in my direct testimony. (Borsch Direct Test., p. 33, lines 19-23, p. 34, lines 1-3 and Exhibit No. ____ (BMHB-7)).

DEF also was developing generation resource options in its IRP process to meet its need prior to 2018. This process and the selection of the Company's Suwannee Simple Cycle Project, and ultimately too the selection of the Hines Chillers Power Uprate Project, to meet DEF's need prior to 2018 are described in detail in my direct testimony. (Borsch Direct Test., pp. 7-27). DEF planned to evaluate the revised bid proposals in 2013 against its Suwannee Simple Cycle Project, and later included the Hines Chillers Power

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Uprate Project, to determine the most cost effective alternative to meet its need prior to 2018.

Q. What were the NRG and Calpine generation capacity proposals to meet DEF's need prior to 2018?

A. NRG made two proposals to DEF to meet DEF's generation capacity needs prior to 2018. One NRG proposal [redacted] and the second was an acquisition proposal or an offer to sell the NRG three combustion turbine ("CT"), 471MW plant to DEF. This is the "Acquisition 1" proposal that NRG witness Mr. Pollock recommends as an alternative to DEF's self-build generation projects in his direct testimony. Both NRG proposals are identified in Exhibit No. ____ (BMHB-7) and Exhibit No. ___ (BMHB-8) to my direct testimony.

Calpine also submitted [redacted] and an acquisition proposal to DEF to meet DEF's need for generation capacity prior to 2018. Calpine's separate acquisition proposal was an offer to sell its 594MW combined cycle power plant to DEF. Calpine's PPA and acquisition proposals are also identified in Exhibit No. ____ (BMHB-7) and Exhibit No. ___ (BMHB-8) to my direct testimony.

These NRG and Calpine proposals were evaluated in DEF's generation resource options assessment that is described in detail in my direct testimony and exhibits in this Docket. As I explain there, based on that assessment, including all quantitative and qualitative costs and risks, the Company determined that the most cost effective generation to meet its need prior to 2018 was the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project. (Borsch Direct Test., pp. 32-49, Exhibits Nos. ___ (BMHB-7) to ____ (BMHB-11)).

Q. Were NRG and Calpine notified by the Company that their proposals were not the most cost effective generation alternative to meet DEF's need prior to 2018 before the Company filed its Petition and direct testimony in this Docket?

A. Yes. Both Calpine and NRG were notified in February 2014 that their PPA proposals were not the most cost effective generation resource option to meet DEF's generation capacity need prior to 2018. In February, DEF also notified both NRG and Calpine of the results of the detailed economic analysis with respect to their acquisition proposals.

In particular, DEF informed both NRG and Calpine about the qualitative factors and costs that were not fully developed in the Company's detailed economic analysis that are represented by the "bars" in the cost sensitivities associated with their proposals in Exhibit No. ___ (BMHB-9) to my direct testimony -- such as, for example, the fuel arrangements for the NRG plant and the transmission constraints associated with the delivery of the Calpine plant's full capacity to DEF. DEF also informed NRG and Calpine about the potential FERC Competitive Analysis Screen issues associated with their acquisitions. DEF told NRG and Calpine that DEF had retained Julie Solomon with Navigant Consulting, Inc. to address the FERC Competitive Analysis Screen for both the NRG and Calpine acquisition proposals. These issues associated with the NRG and Calpine acquisition proposals are discussed in my direct testimony. (Borsch Direct Test., pp. 40-43).

B. NRG AND CALPINE CONTINUING DISCUSSIONS WITH DEF ABOUT THEIR PROPOSALS TO MEET DEF'S NEED PRIOR TO 2018.

Q. What happened after DEF notified NRG and Calpine in February 2014 of these results of DEF's evaluation of their proposals?

A. DEF met with NRG and Calpine by phone or in person to discuss the factors and costs associated with their acquisition proposals that were not fully developed in their proposals that presented quantitative or qualitative risk to the Company if their acquisition proposals were selected to meet DEF's generation capacity need prior to 2018. For example, DEF questioned NRG about firm gas transportation issues associated with the NRG acquisition proposal. DEF also met with Calpine in mid-February 2014 to discuss the firm transmission constraints associated with the Calpine acquisition. DEF further informed both NRG and Calpine of the results of Ms. Solomon's FERC Competitive Analysis Screen that showed both the NRG and Calpine acquisition proposals failing the Screen. DEF later brought Ms. Solomon to Florida to discuss the FERC Competitive Analysis Screen and the results of her Screen analyses for the NRG and Calpine acquisitions with the Office of Public Counsel on May 12, 2014. One purpose of this meeting was to explain the results of DEF's evaluation of the most cost effective generation alternative to meet its need prior to 2018. Other parties attended this meeting, including Calpine's attorney.

The purpose of these discussions between the Company and NRG and Calpine was to focus on the quantitative and qualitative factors in their acquisition proposals that were impediments to the selection of their proposals to meet DEF's need prior to 2018 and to discuss what could be done by NRG and Calpine, if anything, to overcome them. DEF made clear to NRG and Calpine that, based on the quantitative and qualitative risks associated with their acquisition proposals that were identified in DEF's evaluation, their proposals were not more cost effective than the Suwannee Simple Cycle Project and Hines Chillers Power Uprate Project.

Q. Were any revisions made by either NRG or Calpine to their proposals during or following these discussions with the Company?

A. No. DEF received no revisions from either NRG or Calpine to their proposals to meet DEF's need prior to 2018 to address the impediments that DEF identified with the selection of their proposals. DEF formally announced its selection of the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project as the most cost effective generation alternative to meet its need prior to 2018 on May 13, 2014. Both NRG and Calpine were informed of this decision.

Q. Were there any revised proposals from NRG or Calpine after DEF's announcement?

A. No, not before DEF filed its Petition and Direct Testimony and Exhibits in this Docket. NRG did not submit any proposal to DEF during this time period from February 2014 to the end of May 2014. Calpine did submit an acquisition proposal to DEF on April 30, 2014, as Mr. Thornton states in his direct testimony (Thornton Direct Test., p. 7, lines 14-16), but this was the exact same acquisition proposal that Calpine had previously submitted following DEF's September 2013 solicitation and that DEF evaluated in its generation resource evaluation to determine the most cost effective generation alternative to meet its need prior to 2018. Calpine did not submit a revised PPA or acquisition proposal to DEF before DEF filed its Petition and Direct Testimony and Exhibits in this Docket on May 27, 2014.

C. FINAL AND BEST OFFERS.

Q. Did DEF end its discussions with NRG and Calpine about their proposals after DEF filed its Petition in this Docket?

A. No. DEF did not stop taking calls from NRG and Calpine and DEF did not stop communicating with them about their proposals after DEF filed its Petition in this Docket, even though DEF had no obligation to continue such discussions with them. DEF already had informed them about the impediments to selecting their proposals and, although DEF received no response to these impediments prior to DEF filing its Petition in this Docket, DEF was willing to continue the discussions with them because DEF was genuinely interested in purchasing one of their plants if the purchase made sense and offered superior customer value to the Company's self-build generation options. DEF informed both NRG and Calpine of the continuing discussions with DEF and both parties. DEF encouraged both NRG and Calpine to give DEF a final and best offer for the acquisition of their plants with a plan to deal with any FERC Competitive Analysis Screen issue associated with the plant acquisition.

Q. Was there more than one discussion with NRG and Calpine about a final and best offer to DEF?

A. Yes. From late May to early July 2014, DEF had numerous communications and calls with NRG and Calpine regarding their plant acquisition proposals in an attempt to obtain a final and best offer from NRG and Calpine. DEF also met with NRG and Calpine representatives in person, bringing together their lawyers and technical experts with DEF's lawyers and DEF's resource planning and regulatory accounting experts, to determine if there was a way to overcome the economic impediments and qualitative risks associated with their plant acquisitions by DEF structured in a way to get around the FERC market screen failures that DEF's expert had identified with their acquisitions.

Q. Please describe your discussions with NRG.

A. DEF met with NRG on May 27, 2014 and on June 12, 2014. During these meetings DEF discussed the details of its evaluation of NRG's acquisition proposal and the economic, qualitative, and FERC market screen impediments to DEF selecting this acquisition over its self-build generation options. DEF provided the details of this evaluation to NRG and DEF provided NRG with DEF's evaluation of NRG suggested proposals to structure the NRG plant acquisition in a way that evaded any FERC market screen failures while holding DEF and its customers harmless from any costs that would occur if FERC approval was not obtained or if FERC required mitigation to eliminate the market screen failures that DEF's expert identified with the NRG acquisition. DEF continued correspondence and communications with NRG about the structure of the NRG plant acquisition between and after these meeting dates into early July 2014. Copies of the written communications between DEF and NRG during this period are included as a composite Exhibit No. ___ (BMHB-12) to my rebuttal testimony.

Q. Were there similar discussions between DEF and Calpine?

A. Yes. DEF continued its communications with Calpine to obtain a final and best plant acquisition offer from Calpine. DEF met with Calpine on June 2, 2014 and had follow up conference calls with Calpine on June 9, June 11, and July 1, 2014. DEF provided Calpine with the details of DEF's evaluation of Calpine's acquisition proposal and the economic, qualitative, and FERC market screen impediments to DEF selecting this acquisition over its self-build generation options. Following each of these meetings DEF analyzed Calpine's alternative proposals to overcome the economic and qualitative impediments to the acquisition of Calpine's plant. DEF also analyzed and provided Calpine its analysis of Calpine's suggested proposals to structure the Calpine plant acquisition in a way that evaded the FERC market screen failures while ensuring that DEF's customers did not incur any costs if FERC approval was not obtained or if FERC required mitigation to eliminate the market screen failures that DEF's expert had identified with the Calpine acquisition. DEF continued correspondence and communications with Calpine about the structure of the Calpine plant acquisition between and after these meeting dates into early July 2014. Copies of the written communications between DEF and Calpine during this period are included as a composite Exhibit No. ____ (BMHB-13) to my rebuttal testimony.

Q. The structure of these proposals sounds complicated, why were the proposals structured this way?

A. They were complicated proposals. The only proposals to meet DEF's need prior to 2018 that were potentially cost effective for DEF's customers were the proposed acquisitions. These acquisitions were the only long-term proposals ever submitted by NRG or Calpine to meet DEF's need prior to 2018 and they were more economic than the PPA proposals that NRG and Calpine submitted. If DEF was going to do a deal with either NRG or Calpine for the benefit of DEF's customers that deal would be for the acquisition of either the NRG plant or the Calpine plant.

The straight-forward acquisition of the plants, which is what both NRG and Calpine originally proposed, however, failed the FERC Competitive Analysis Screen. FERC approval of the NRG and/or Calpine plant acquisitions was required. The FERC Competitive Analysis Screen failures for both acquisitions meant that DEF likely could not obtain FERC approval to acquire the plants without undertaking substantial transmission mitigation to expand the DEF market and eliminate the screen failures. These FERC Competitive Analysis Screen failures for both the NRG and the Calpine straight-forward acquisition proposals and the likely substantial transmission mitigation required to eliminate the screen failures are described in detail in the direct testimony and exhibits of Julie Solomon in this Docket. No NRG or Calpine witness disputes Ms. Solomon's direct testimony and analysis that the straight-forward acquisitions of the NRG and Calpine plants fail the FERC Competitive Analysis Screen and that substantial transmission mitigation is likely necessary to eliminate the screen failures. In fact, Calpine witness Dr. Hunger expressly agrees with her testimony and analysis of the FERC Competitive Analysis Screen for the straight-forward DEF acquisitions of the NRG and Calpine plants. (Hunger Direct Test., p. 20, lines 1-13). This risk of FERC disapproval, or the likelihood of FERC approval only if substantial mitigation costs were incurred, prevented DEF from pursuing a straight-forward, economic plant acquisition proposal from NRG or Calpine.

Q. Was this FERC problem a primary reason for the complicated structure of the NRG and Calpine proposals?

A. Yes. One of the primary focuses of the continued discussions with both NRG and Calpine to obtain a best and final acquisition offer from them was how to structure the deal to get DEF the value of the acquisition of the plants without running afoul of the FERC Competitive Analysis Screen. Both NRG and Calpine asserted that all DEF had to do was enter into a PPA with an acquisition option or requirement to avoid the FERC Competitive Analysis Screen and, therefore, obtain FERC approval. NRG and Calpine disagreed and continue to disagree on the length of that PPA, and how soon DEF could seek FERC approval of the acquisition in the PPA in order to get out of the PPA if FERC did not approve it or if FERC required mitigation. This is evident in the direct testimony of NRG witness Dr. Morris and Calpine witness Dr. Hunger in this Docket. (Hunger Direct Test., p. 4, lines 8-10, p. 17, lines 21-22; Morris Direct Test., p. 12, lines 20-21, p. 13, lines 1-10, p. 18, lines 18-21).

DEF's position then and now is that if NRG and Calpine are so sure that FERC would approve their proposed PPA structures to consummate DEF's acquisition of their plants as soon as possible, then, NRG and Calpine should bear all risks associated with obtaining or failing to obtain that approval from FERC. This included, among other costs, (i) all the sunk costs and the costs associated with deferring the Suwannee Simple Cycle Power Plant at least a year to attempt to obtain FERC approval of the acquisition; (ii) the additional, extra PPA costs associated with the PPA term until the acquisition could be

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consummated; and (iii) all costs, including legal and expert fees, at FERC to attempt to obtain FERC approval of the PPA with the acquisition option. In other words, DEF expected NRG and Calpine to take all the risk --- not DEF's customers --- that FERC would not approve their proposed PPA structure with the plant acquisition to get DEF the value of the acquisition as soon as possible without substantial mitigation. Structuring the deal to accomplish this objective was complicated.

1. NRG'S FINAL AND BEST OFFER.

Q. Did NRG make a final and best offer to DEF?

A. Yes. NRG submitted a final and best offer to DEF on June 18, 2014. NRG's final and best offer was intended, we believe, to address DEF's quantitative and qualitative concerns with NRG's original acquisition proposal including the FERC Competitive Analysis Screen failure. NRG's final and best offer is included as Exhibit No. ___ (BMHB-14) to my rebuttal testimony.

Q. Were DEF's concerns addressed in NRG's final and best offer?

A. No. NRG's final and best offer was at least [redacted] negative on a Cumulative Present Value Revenue Requirements ("CPVRR") basis compared to the Suwannee Simple Cycle Project and Hines Chillers Power Uprate Project. NRG proposed [redacted]

[redacted]

[redacted]. DEF's response to NRG and evaluation of NRG's final and best offer is included in Exhibit No. ___ (BMHB-15) to my rebuttal testimony.

Q. Does NRG refer to its final and best offer to DEF in its direct testimony?

A. No. No NRG witness in this Docket argues or recommends that DEF should have selected the NRG final and best offer as the most cost effective alternative to meet DEF's generation capacity need prior to 2018.

The only NRG witness is a witness who challenges DEF's firm gas transportation requirements for the NRG plant if DEF acquired the plant. (See Dauer Direct. Test., p.3). He refers only to the NRG initial acquisition proposal --- Acquisition 1 --- to meet DEF's 2018 generation capacity need. (Id.). He does not mention or describe NRG's final and best offer to DEF.

NRG witness Mr. Pollock is an expert retained by NRG to testify in this Docket and NRG witness Mr. Pollock recommends the initial NRG plant acquisition proposal --- Acquisition 1 --- that NRG made to DEF to meet DEF's 2018 need. (Pollock Direct Test., pp. 6-7, 28). NRG witness Mr. Pollock does not even mention much less describe the NRG final and best offer.

The NRG plant acquisition that NRG witness Mr. Pollock recommends is the plant acquisition that was not more cost effective on a quantitative and qualitative basis than the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project, for the reasons provided in my direct testimony, and that failed the FERC Competitive Analysis Screen for the reasons provided in the direct testimony of Julie Solomon in this Docket. (Borsch Direct Test., p. 40-48; Solomon Direct Test., p.20, lines 13-23, p. 21, lines 1-4, pp. 22-23).

Q. Does NRG witness Dr. Morris disagree with the FERC Competitive Analysis Screen analysis performed for the NRG Acquisition 1 proposal recommended by Mr. Pollock?

A. No. NRG witness Dr. Morris does not even mention the NRG Acquisition 1 proposal at all in his direct testimony --- despite the fact that NRG witness Mr. Pollock actually recommends the Acquisition 1 proposal to DEF and the Commission as the most cost effective alternative to meet DEF's need prior to 2018. (Morris Direct Test., p. 5, lines 15-20, pp. 6-6; p. 12, lines 20-21, p. 13, lines 1-10; Pollock Direct Test., p. 6, lines 18-21). No NRG witness testifies that the NRG Acquisition 1 proposal passes the FERC Competitive Analysis Screen or that it would otherwise be approved by FERC without mitigation. NRG, then, does not dispute the testimony of Ms. Solomon that the NRG Acquisition 1 proposal fails the FERC Competitive Analysis Screen and that FERC likely would not approve the acquisition without substantial mitigation.

Q. Does Dr. Morris address the NRG final and best offer in his direct testimony?

A. No. Dr. Morris does not refer to or describe NRG's final and best offer. In fact, Dr. Morris does not refer to any actual NRG contract proposal for the acquisition of the NRG plant by DEF at all in his direct testimony.

Dr. Morris discusses hypothetical PPAs of various terms, from five to ten years, with or without tolling arrangements, with the option for DEF to "purchase the [NRG] facility at <u>some</u> date under <u>some</u> <u>set of terms</u>." (Morris

Direct, Test. p. 12, lines 20-21, p. 13, lines 1-10, p. 18, lines 14-21) (emphasis added). Dr. Morris concludes that these hypothetical PPAs with an acquisition option would pass muster at FERC because they would be -- if they existed -- PPAs under which DEF had the rights to the NRG plant capacity for some time and, therefore, would similarly control that output at the time of the acquisition "several" years later, thus, demonstrating no change of control triggering a FERC market screen analysis or screen failure. (Morris Direct Test., p. 14, lines 5-8). That may or may not be true, Dr. Morris is correct that Ms. Solomon did not perform that analysis (Morris Direct Test., p. 11, lines 3-6), because there is nothing to analyze. There simply are no terms for DEF to evaluate to determine the economic value to customers.

Remarkably, Dr. Morris fails to address the actual facts of this case, involving the NRG initial Acquisition 1 proposal and the NRG final and best offer attempt to address the quantitative and qualitative impediments to the cost-effectiveness of that proposal and the NRG proposed FERC market screen "work around" to sell the plant to DEF. Dr. Morris chooses to ignore NRG's final and best offer.

Dr. Morris also claims that Ms. Solomon and DEF failed to consider a case before FERC where, if the NRG Acquisition 1 proposal was not accepted by DEF --- which is the case because it is not cost effective --- NRG would either exit the DEF Balancing Area Authority ("BAA") by physically moving its CT plant to another location outside the DEF BAA or "moving out" its plant by selling the capacity or plant to another utility outside the DEF BAA. (Morris

Direct Test., p. 11, lines 7-10; p. 14, lines 15-21, pp. 15-16). Dr. Morris is correct that DEF and Ms. Solomon did not consider these "cases" because, again, they have nothing to do with the actual facts in this case.

NRG never told DEF that it was actually going to move its CTs outside the DEF BAA or that NRG had a contract to sell its plant capacity or its entire plant to a utility outside the DEF BAA if DEF did not accept its Acquisition 1 proposal or its final and best offer. See Exhibit No. ___ (BMHB-12) to my rebuttal testimony. NRG's final and best offer to DEF contains no such factual representations. See Exhibit No. ____ (BMHB-14). No NRG witness has testified in this Docket that NRG will in fact move its CTs outside the DEF BAA or that NRG in fact has an alternative contract to sell its plant capacity or its entire plant to a utility outside the DEF BAA if DEF does not accept its Acquisition 1 proposal. Simply put, DEF could not and did not evaluate what factually never existed. Nonetheless, Ms. Solomon addresses these arguments and their impact to FERC issues in her rebuttal testimony.

2. CALPINE'S FINAL AND BEST OFFER.

Q. Did Calpine make a final and best offer to DEF?

A. Calpine made a couple of final and best offers to DEF. The first Calpine final and best offer was presented to DEF on June 16, 2014. Calpine's June 16, 2014 final and best offer is included as Exhibit No. ___ (BMHB-16) to my rebuttal testimony. The last one is the July 3, 2014 proposal that witness Mr. Thornton identifies and generally describes in his direct testimony. (Thornton

Direct Test., pp. 8-9). Calpine's July 3rd final and best offer is included as Exhibit No. ____ (BMHB-17) to my rebuttal testimony.

Q. What was the first final and best offer that Calpine made to DEF?

A. Calpine proposed [redacted]

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[redacted] See Exhibit No. ___ (BMHB-16) to my rebuttal testimony.

Q. What was DEF's response to the Calpine June 16th offer?

A. DEF could not accept this offer because it did not "close the gap" between the [redacted]

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[redacted] DEF explained this to Calpine in a June 26, 2014 letter that is included in Exhibit No. ___ (BMHB-13) to my rebuttal testimony.

Q. What was Calpine's response to DEF's concerns in DEF's June 26, 2014 letter to Calpine?

A. Calpine's response was to make its July 3rd final and best offer to DEF. Calpine witness Mr. Thornton correctly describes this July 3rd offer in his direct testimony as a five-year PPA for 515MW of capacity and energy with a guaranteed heat rate and plant availability. Calpine lowered the capacity payments during the PPA. (Thornton Direct Test., p. 8, lines 2-15; Exhibit No. ___ (BMHB-17) to my rebuttal testimony). [redacted] provided DEF the option to purchase the plant for [redacted] "subject to certain adjustments the terms of which would be negotiated by Calpine" and DEF. (Thornton Direct Test., p. 8, lines 15-19). Calpine further provided for the first time terms that addressed the risk that FERC might not approve the Calpine

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PPA-acquisition proposal or that FERC might approve it only with mitigation. All other terms of the Calpine July 3rd final and best offer remained the same as the June 16th Calpine offer. See Exhibit No. ___ (BMHB-17) to my rebuttal testimony. In this final and best offer Calpine attempted to address DEF's concerns with its initial plant acquisition proposal and its June 16th final and best offer and to "close the gap" between the cost effectiveness of the Calpine plant acquisition and the Company's Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project to meet DEF's need prior to 2018.

Q. Was the Calpine July 3rd final and best offer more cost effective for DEF's customers than the Company's self-build generation projects?

A. No. On a CPVRR basis, accounting for all the costs to DEF of the Calpine July 3rd final and best offer, the Calpine July 3rd offer is still [redacted] less cost effective in a FERC no mitigation scenario, [redacted] less cost effective in a FERC mitigation scenario where DEF has to default to a delayed DEF self-build generation plan, and [redacted] less cost effective if DEF were to accept the full five years of the PPA with no acquisition. Calpine moved closer to the cost-effectiveness of DEF's self-build generation resources to meet DEF's need prior to 2018, but Calpine did not fully close that gap, thus, the Company's Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project are still the most cost effective generation capacity resources to meet DEF's need prior to 2018. Please see DEF's evaluation of Calpine's July

3rd final and best offer attached as Exhibit No. ___ (BMHB-18) to my rebuttal testimony.

Q. Calpine witness Mr. Hibbard claims that the Calpine July 3rd final and best offer not only closed the gap but that it is actually $133 million more cost-effective than the Company's self-build generation projects to meet DEF's need prior to 2018. Do you agree with Mr. Hibbard?

A. No. Mr. Hibbard is wrong. First, he fails to include transmission costs to deliver the Calpine plant capacity across TEC's system to DEF that he and Calpine witness Mr. Simpson acknowledge must exist. Second, he fails to include costs that necessarily result from the deferral of the Calpine plant acquisition to a later point in time. Third, he makes an adjustment to DEF's planned firm gas transportation to incorporate the Calpine plant into DEF's generation system that fails to recognize that DEF is operating a generation system to meet its statutory obligation to serve its customers --- not a single combined cycle plant operated on a merchant basis like Calpine --- and actually results in higher future firm gas transportation costs to incorporate that plant into DEF's generation system. Fourth, he fails to include costs that Calpine itself admits exist if DEF defers its self-build generation project in an attempt to obtain FERC approval of the Calpine PPA-acquisition proposal. Finally, Mr. Hibbard ignores qualitative risks that add cost to the Calpine proposed PPA-acquisition, including the assumption that there is no FERC approval or mitigation risk, even though his own client accounted for that risk in Calpine's July 3rd proposal, albeit in a manner that did not fully address that risk in a cost effective manner. For all these reasons, Mr. Hibbard is wrong and the Calpine July 3rd final and best offer still is not a cost effective option, considering all quantitative and qualitative factors, to meet DEF's need prior to 2018. See Exhibit No. ___ (BMHB-18) to my rebuttal testimony.

Q. Can you explain the transmission costs that Mr. Hibbard does not account for in his analysis of the CPVRR impact of the Calpine July 3rd offer?

A. Yes. Calpine and Mr. Hibbard now acknowledge there are $150 million in transmission costs to provide a direct connection from the Calpine plant to DEF's system to ensure the firm transmission of the full plant capacity to DEF (Thornton Direct Test., p. 14, lines 9-12; Hibbard Direct Test., pp. 25-26). However, the $150 million in transmission costs for the direct connection of the Calpine plant to DEF's system are <u>future</u> costs since even Calpine acknowledges DEF will not want to incur these costs until FERC approves the ultimate acquisition of the Calpine plant (Thornton Direct Test., p. 10, Lines 7-11), and Calpine admits it will take at least three years to construct this necessary transmission to ensure DEF can obtain the Calpine plant capacity "year-round on a long-term basis." (Thornton Direct Test., p. 10, lines 4-7; Simpson Direct Test., p. 14, line 13). In the meantime, under the PPA in the July 3rd Calpine offer, under which Calpine requires DEF to pay for the full

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plant capacity year-round, DEF does not have firm transmission rights to obtain the full plant capacity across TEC's system and onto DEF's system.

Mr. Hibbard admits --- contrary to Mr. Simpson's testimony --- that only 249MW of the Calpine plant capacity can be supplied on a firm basis under the PPA prior to the new $150 million transmission infrastructure. (Hibbard Direct Test., p. 13, lines 21-23). While Mr. Simpson takes the position that the Calpine plant can firmly deliver DEF more than 249MW of plant capacity even before the new transmission infrastructure is constructed with the use of operating procedures and re-dispatch of generation resources by both DEF and TEC, he at least admits that "additional transmission service will need to be purchased from TEC for the delivery of additional energy and capacity" from Calpine's plant to DEF. (Simpson Direct Test., p. 8, lines 12-14). Mr. Hibbard does not include the costs for this additional transmission service to deliver the full plant capacity to DEF under the PPA in the Calpine July 3rd offer in his CPVRR adjustments. DEF, in its evaluation of the Calpine offer, attempted to address these issues by modeling a scenario in which the available transmission capacity was limited to 249MW during four peak months of the year and the full 515MW was available during the remaining eight months, shaping the expected transmission charges owed to TEC accordingly. The cost of this transmission service over the term of the PPA in the July 3rd offer has a negative CPVRR impact of [redacted] for the Calpine PPA-acquisition proposal. Mr. Hibbard ignores these costs in his adjustments to the CPVRR evaluation in his direct testimony.

Q. Do you agree with Mr. Simpson that DEF can receive the full capacity of the Calpine plant and that the plant is not limited to delivering only 249MW of plant capacity to DEF before the additional transmission infrastructure to directly connect the plant to DEF is built?

A. No. On this point Mr. Hibbard is correct, under the proposed PPA before the plant acquisition and the transmission infrastructure is constructed, Calpine is limited to providing DEF 249MW of plant capacity on a firm basis. Mr. Simpson himself concedes that this limit applies during peak load hours of the year --- which of course is when DEF will actually need the full plant capacity -- - unless operating procedures are employed or DEF or TEC or both re-dispatch their generation resources to avoid overloads and other transmission constraints he admits exist on the grid. (Simpson Direct Test., pp. 11-12). Mr. Scott addresses this argument in his rebuttal testimony from the transmission perspective, but from the resource planning perspective, Mr. Simpson's suggested ways around the transmission constraints at peak hours to deliver the full plant 515MW capacity to DEF do not turn non-firm transmission capacity into firm transmission capacity. I am responsible for ensuring that DEF meets its statutory obligation to serve and, during peak load hours, the Calpine plant under the July 3rd Calpine offer is only a 249MW firm generation resource.

No utility with an obligation to serve will rely on transmission operating procedures or the re-dispatch of other generation resources by another utility in an attempt to avoid or limit transmission constraints as firm transmission generation. That simply is not standard utility practice. Indeed, by re-dispatching generation resources Mr. Simpson means that the utilities are deciding to change the economic dispatch of generation resources just to avoid transmission constraints. This might be a temporary measure by a utility managing its own generation resources to mitigate a limited transmission constraint, but re-dispatching otherwise economically dispatched generation to avoid transmission constraints is obviously not the most cost effective allocation of generation resources. Also the suggestion that re-dispatch may be utilized during peak hours is only feasible if the utilities have sufficient generation flexibility at peak to de-rate selected generation units while still being able to meet peak load. Neither Mr. Simpson nor Mr. Hibbard account for the cost of this inefficient allocation of generation resources in their direct testimony despite advocating this approach and Calpine nowhere in its July 3rd proposal offered to pay DEF and its customers for this cost to accommodate the transmission of Calpine's plant capacity to DEF. As discussed above, DEF in its evaluation modeled this constraint by shaping the available transmission in peak and off-peak months.

In addition, neither Calpine, Mr. Hibbard, or Mr. Simpson account for the cost of the uneconomic dispatch on TEC's system, even if TEC was inclined to agree to the uneconomic re-dispatch of its generation resources on its system to accommodate the delivery of Calpine's plant capacity across TEC's system to DEF. Surely Calpine and its witnesses do not expect DEF's

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customers and TEC's customers to assume this uneconomic re-dispatch cost to enable Calpine to deliver its full plant capacity to DEF when it is needed.

Q. What costs are associated with the plant acquisition at a later date under the July 3rd offer that Mr. Hibbard does not include in his analysis?

A. DEF included costs to account for the Calpine plant condition including necessary expected maintenance contract and other costs to align the maintenance of the Calpine plant with DEF's other combined cycle generation plants if the Calpine plant was acquired by DEF. The Calpine plant, despite Calpine's witnesses' claims about its reliable operation, is ten years old and it will be at least 15 years old at the latest time of the acquisition under the Calpine July 3rd PPA-acquisition offer. Notably, Calpine failed to guarantee upon acquisition the performance or maintenance of the Calpine plant in its July 3rd offer. DEF included direct costs of [redacted] with a CPVRR impact o[redacted]. It is unreasonable for Calpine and Mr. Hibbard to ignore any additional cost to DEF to maintain and incorporate a 15-year old plant into its system. See Exhibit No. ___ (BMHB-18).

In addition, DEF included transaction costs for the actual plant acquisition, which again, Calpine failed to include in its July 3rd offer and Mr. Hibbard failed to include in his CPVRR adjustments. Calpine must admit that there would necessarily be such transaction costs, because even Calpine explains that its offer was <u>not</u> final, but instead subject to negotiation. (Thornton Direct Test., pl. 8, lines 15-16; p. 9, lines 10-12). These costs also

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impact the economic comparison of the Calpine July 3rd offer to the Company's self-build generation projects. DEF included a [redacted] estimate for these costs. See Exhibit No. __ (BMHB-18).

Q. Why is Mr. Hibbard's firm gas transportation cost adjustment incorrect?

A. Mr. Hibbard makes a substantial [redacted] adjustment to the CPVRR economic evaluation of the Calpine July 3rd proposal based on his unwarranted and unsupported assumption that [redacted]. (Hibbard Direct Test., p. 32, lines 1-6). In other words, Mr. Hibbard says DEF should simply [redacted] Mr. Hibbard claims this is a fair allocation because DEF purchases gas on a system or fleet-wide basis, and, therefore, according to him, to level "the playing field" between DEF generation resources and third-party proposals the DEF firm gas transportation contracts should be transferable to any proposal including Calpine's proposal. (Hibbard Direct Test., pp. 30-31).

Mr. Hibbard makes an unsupported assumption that the gas transportation contracts which supply the Suwannee site can be redirected to the Calpine Osprey plant location. This is not correct. Different gas transportation contracts have different and specific delivery points and there are limits to the degree to which they can be interchangeable or redirected. Specifically, the Suwannee plant is supplied by Florida Gas Transmission ("FGT") while the Calpine Osprey plant site is supplied by Gulfstream. DEF cannot simply redirect its transportation from one pipeline network to the other and would require service on each system to supply different locational needs. Neither can DEF reasonably release its contracted FGT capacity, which is an integral part of its portfolio with delivery to multiple DEF sites, and "replace" it with the transportation contracted to the Calpine Osprey plant.

Mr. Hibbard, of course, does not work for any public utility, much less DEF, so he has no basis to testify at all to how public utilities and DEF, in particular, purchase firm gas transportation for their systems. Mr. Patton is responsible for firm gas transportation for DEF on DEF's system and provides rebuttal testimony in this Docket addressing Mr. Hibbard's erroneous assumptions. From a resource planning perspective, I know that the fact that DEF purchases firm gas transportation to serve its generation fleet on a system basis does not mean that DEF simply can transfer firm gas transportation from one generation resource to another generation resource on its system or to generation resources not on its system yet, like the Calpine plant under the PPA part of the July 3rd PPA-acquisition offer. This is not the "one-size-fits-all" simplistic view that Mr. Hibbard applies to his firm gas transportation adjustment.

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As mentioned above, there is another reason Mr. Hibbard's simplistic view is inaccurate. If DEF has reserved firm gas transportation now for its Suwannee Simple Cycle Project it does not make economic sense for DEF and its customers to give that firm gas transportation up now for the Calpine proposal or any other proposal only for DEF to have to buy back future firm gas transportation at a higher price when DEF knows its system is growing. Mr. Hibbard's firm gas transportation CPVRR adjustment fails to compensate DEF's customers for the differential cost that is lost if DEF must purchase firm gas transportation in the future at a higher cost to replace the firm gas transportation it has now but must give up to Calpine under Mr. Hibbard's simplistic view of the use of system firm gas transportation resources.

Q. Did Mr. Hibbard account for the costs associated with the extended operation of the Suwannee Steam units?

A. No. One of the benefits of the construction of the Suwannee Simple Cycle Project is that it allows for retirement of the more than 50-year old Suwannee Steam units in 2016. Both Calpine and Mr. Hibbard failed to account for the cost to extend the retirement of the Suwannee steam units from 2016 to 2018 if FERC approves the Calpine July 3rd PPA-acquisition proposal without mitigation. The Suwannee steam units are needed for transmission grid reliability in the North Florida area between 2016 and 2018 if the Suwannee Simple Cycle Project is not placed in commercial operation in 2016. DEF included these costs with a CPVRR impact of [redacted] in its analysis.

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Q. What additional costs did Mr. Hibbard fail to include for the deferral of the self-build generation projects while DEF and Calpine attempt to obtain FERC approval for the Calpine PPA-acquisition proposal?

A. As explained above, DEF announced in May 2014 that the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project were the most cost effective generation capacity to meet DEF's need prior to 2018. DEF filed its Petition and Direct Testimony in support of that determination and DEF necessarily is incurring costs to ensure that the Suwannee Simple Cycle Project can be completed in time to meet DEF's need in 2016 --- all before DEF received the Calpine final and best offer, which is still subject to FERC approval. There are, therefore, sunk costs associated with this Project that Calpine --- not DEF's customers --- must assume. [redacted] Mr. Hibbard fails to include this cost in his CPVRR analysis entirely.

Finally, there obviously will be costs, including legal and expert fees, associated with any attempt to obtain FERC approval of the Calpine July 3rd PPA-acquisition proposal. [redacted] See Exhibit No. ___ (BMHB-17). Mr. Hibbard never included these costs in his CPVRR analysis. DEF and its customers obviously

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should not be responsible for the costs of obtaining FERC approval for Calpine's July 3rd proposal.

Recognizing that these costs totaling at least [redacted] might be the subject of a future "negotiation" on the final purchase price, DEF did not directly include these in its CPVRR analysis, but DEF has identified them as a potential reduction in any benefit to customers if Calpine is not willing to fully net them against the purchase price.

Q: Did Calpine offer any offset to the Suwannee Project Costs?

A. Calpine offered [redacted] its July 3rd offer. (See Exhibit No. ___ (BMHB-17); Thornton Direct Test., p. 9, lines 7-9) [redacted] See Exhibit No. ___ (BMHB-18) to my rebuttal testimony. [redacted] See Exhibit No. ___(BMHB-17).

Q. Please explain the qualitative factors that add risk and cost to the Calpine July 3rd offer.

A. As I explained above, Calpine acknowledges that many of the terms and conditions of Calpine's July 3rd PPA-acquisition proposal remain to be negotiated and, in Calpine's view, are "subject to certain adjustments." (Thornton Direct Test., p. 8, lines 9-10). This includes the terms for the actual purchase price for the acquisition of the Calpine plant by DEF. (Id.). It also includes a reference to the PPA "escape clause" in the event that FERC did not approve the Calpine July 3rd PPA-acquisition offer. (Thornton Direct Test., p. 9, lines 1-13). The fact that these critical terms remain subject to negotiation and "adjustment" hardly means DEF has a deal where all costs are known and all risks have been mitigated or allocated between DEF and Calpine. There are, therefore, qualitative risks associated with the Calpine July 3rd PPA-acquisition offer that represent risk and additional cost to DEF and its customers.

Q. What do you mean by the PPA "escape" clause?

A. As I explained above, the value, if any, of the Calpine proposal to DEF's customers is the <u>immediate</u> acquisition of the Calpine plant. A PPA for the Calpine plant capacity is not economic for DEF's customers and, in fact, the longer DEF is in a PPA prior to the plant acquisition, the less economic the deal is for DEF's customers. In other words, the PPA does not add value to the acquisition transaction; it detracts from the value of the acquisition transaction.

The only reason that DEF entertained a PPA with the plant acquisition was because Calpine claimed that Calpine could structure a PPA to provide the acquisition value to DEF while at the same time passing FERC muster when the straight-forward acquisition failed the FERC Competitive Analysis Screen. DEF was willing to entertain this structure if DEF could get to the

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plant acquisition value --- if there was economic value to DEF customers to the plant acquisition in the deal --- as soon as possible by obtaining early FERC approval of the PPA-acquisition offer, and, if FERC did not approve the PPA-acquisition proposal or FERC approved it subject to required mitigation, DEF could get out of the PPA. Hence, the “escape” clause that DEF required and that Calpine finally provided in the July 3rd PPA-acquisition proposal, albeit still subject to further negotiation on the final terms. See Exhibit No. ___ (BMHB-17).

This “escape” clause provision necessarily committed DEF to a minimum two-year PPA with Calpine while DEF and Calpine sought FERC approval of the PPA-acquisition proposal and, if it was not approved or was only approved subject to required mitigation, DEF deferred the in-service of the Suwannee Simple Cycle Project to 2017. This “escape” clause detracted from the value of the Calpine July 3rd offer. In fact, the minimum two-year PPA under the “escape” clause resulted in a negative CPVRR impact of [redacted] compared to the Company’s self-build generation projects. See Exhibit No. ___ (BMHB-18). Neither Calpine nor Mr. Hibbard account for this negative CPVRR impact. They both ignore it in their direct testimony.

Q: Did Calpine offer an offsetting payment in this case?

A: DEF identified, and Calpine recognized, that in the event that DEF suspended the Suwannee Project during the period of consideration by FERC, DEF would incur costs regardless of FERC’s eventual ruling on the Calpine PPA-

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acquisition proposal. In the event of FERC approval, DEF and Calpine would have to negotiate, in advance, a settlement for the project costs so that they would not accrue to customers as discussed earlier. In the event that FERC does not approve the Calpine PPA-acquisition proposal, or requires mitigation, DEF would incur cost for suspending and restarting the project as well as carrying costs for the funds already committed and the costs for extended operation of the Suwannee steam units.

Calpine offered [redacted] (See Exhibit No. ___ (BMHB-17) and Thornton Direct Test., p. 9, lines 7-9). [redacted] See Exhibit No. ___ (BMHB-18) to my rebuttal testimony. [redacted] See Exhibit No. ___ (BMHB-17). Mr. Hibbard, however, failed to include [redacted] in his analysis.

Finally, [redacted] are based on DEF's ability to exercise the "escape clause" at the end of year two of the PPA (or in 2016). If the PPA were to run the full 5-year period, the alternative would be significantly worse in CPVRR impact compared to proceeding with the Suwannee Simple Cycle Project now.

Q. What does Calpine say about the FERC review of its July 3rd offer?

A. Mr. Thornton claims that Calpine addressed DEF's FERC concerns in Calpine's July 3rd offer. He refers to Dr. Hunger's direct testimony to support this assertion. (Thornton Direct Test., p. 14, lines 16-23). Dr. Hunger does claim a five-year PPA with an acquisition offer at the end of the PPA will easily obtain FERC approval, even without a FERC Competitive Screen Analysis. (Hunger Direct Test., p. 4, lines 7-10, p. 13, lines 1-7). Dr. Hunger's description of a typical five-year, long-term PPA with an acquisition option at the end likely will pass FERC muster without a FERC Competitive Analysis Screen. The problem is, the Calpine July 3rd offer is not a typical five-year PPA with an acquisition option at the end.

DEF has no intention of entering into a long-term PPA for the Calpine plant capacity with an offer to acquire the plant available at the end of that period. DEF knows that PPA is not economic for DEF's customers. The intent of the PPA, again, is to get to the plant acquisition value, if any, and to obtain that value for DEF's customers by obtaining FERC approval for the acquisition as quickly as possible. Mr. Thornton makes clear he understood this was the intent of the deal when he describes the "escape" clause as a means of protecting DEF in the event that FERC denied DEF's application "for approval of the acquisition." (Thornton Direct Test., p. 9, lines 3-6). Dr. Hunger does not specifically opine on whether FERC would or would not approve this PPA, one in which the parties specifically structured it to evade the FERC market screen issues associated with the straight-forward acquisition of the plant.

Indeed, Dr. Hunger backs off the certainty of his opinion of FERC approval of the five-year PPA with an acquisition option at the end of the term when he moves to his discussion of a situation where the FERC application would be filed as soon as the PPA is executed. In this situation, Dr. Hunger simply states that he believes there is FERC support for this type of structure. (Hunger Direct Test., p. 21, lines 8-18). This "type of structure" is closer to the facts surrounding the July 3rd Calpine PPA-acquisition offer, but it is not that offer. No Calpine witness, Dr. Hunger included, testifies that FERC will approve the Calpine July 3rd PPA-acquisition proposal on these facts with certainty. There is no guarantee of FERC approval of the proposal under the unique facts of this proposal.

Q. Can you sum up the CPVRR comparison of the July 3rd Calpine final and best offer to the Company's self-build projects when the costs excluded by Mr. Hibbard in his CPVRR adjustments are included in the economic evaluation?

A. Yes. The net effect of the inclusion of all costs in the economic evaluation of the Calpine July 3rd final and best offer, including the costs Mr. Hibbard failed to include in his adjustments to the CPVRR evaluation, demonstrates that the

Calpine July 3rd final and best offer is less cost effective by [redacted] in a FERC approval scenario and [redacted] to [redacted] less cost effective in a FERC disapproval or FERC mitigation scenario than the Company's self-build generation projects, depending on the length of the eventual PPA. Please see DEF's evaluation of the Calpine July 3rd offer in Exhibit No. ___ (BMHB-18).

IV. DEF EVIDENCE UNCONTESTED BY INTERVENOR TESTIMONY IN THIS DOCKET.

Q. What issues will the Commission decide in this Docket?

A. My understanding is that the Commission will determine:

(i) Are the proposed Suwannee Simple Cycle Project and Hines Chillers Power Uprate Project needed, taking into account the need for electric system reliability and integrity;

(ii) Are the proposed Suwannee Simple Cycle Project and Hines Chillers Power Uprate Project needed, taking into account the need for adequate electricity at a reasonable cost;

(iii) Are the proposed Suwannee Simple Cycle Project and Hines Chillers Power Uprate Project needed, taking into account the need for fuel diversity and fuel supply reliability;

(iv) Are there any renewable energy sources and technologies or conservation measures taken by or reasonably available to DEF that might mitigate the need for the proposed Suwannee Simple Cycle Project and Hines Chillers Power Uprate Project;

(v) Are the proposed Suwannee Simple Cycle Project in 2016 and the Hines Chillers Power Uprate Project in 2017 the most cost-effective alternative available to meet the needs of DEF and its customers; and

(vi) Did DEF reasonably evaluate all alternative scenarios for cost effectively meeting the needs of its customers over the relevant planning horizon.

Q. Do the NRG and Calpine witnesses challenge the need for the proposed Suwannee Simple Cycle Project in 2016 and the Hines Chillers Power Uprate Project in 2017 to meet DEF's need for electric system reliability and integrity?

A. No. The NRG and Calpine witnesses support their generation capacity proposals to meet DEF's electric system reliability and integrity needs prior to 2018. They do not challenge the fact that there is a reliability need for generation capacity on DEF's system prior to 2018.

Q. Do the NRG and Calpine witnesses challenge the need for the proposed Suwannee Simple Cycle Project in 2016 and the Hines Chillers Power Uprate Project in 2017, taking into account the need for fuel diversity and supply reliability?

A. No. In fact, both NRG and Calpine propose existing natural gas-fired combustion turbine or combined cycle generation units as alternatives to meet DEF's need prior to 2018 and the NRG and Calpine plants are served by existing natural gas pipelines in the State, just like the proposed Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project.

Q. Do the NRG and Calpine witnesses challenge whether there are renewable energy sources and technologies or conservation measures that could have been taken or that were reasonably available to DEF that

might mitigate the need for the proposed Suwannee Simple Cycle Project in 2016 and the Hines Chillers Power Uprate Project in 2017?

A. No. Both NRG and Calpine propose existing supply-side generation resources to meet DEF's reliability need prior to 2018. The NRG and Calpine witnesses do not argue that this need for generation capacity prior to 2018 does not exist because of available renewable energy sources or technologies or conservation measures that DEF could have taken to mitigate its need for generation capacity prior to 2018.

Q. **Do the NRG and Calpine witnesses argue that either the proposed Suwannee Simple Cycle Project in 2016, or the Hines Chillers Power Uprate Project in 2017, is not the most cost effective alternative for DEF and its customers to meet the need for generation capacity prior to 2018?**

A. The NRG and Calpine witnesses assert that their supply-side generation proposals are more cost effective than the Suwannee Simple Cycle Project to meet DEF's need in 2016, but they do not appear to dispute DEF's evidence that the Hines Chillers Power Uprate Project is the most cost effective alternative to meet DEF's need in 2017. In other words, the NRG and Calpine witnesses appear to concede that the Hines Chillers Power Uprate Project is a cost effective generation capacity resource regardless of the generation capacity resource selected by the Company to meet DEF's other generation capacity needs prior to 2018.

To illustrate, while NRG's witness argues that its proposal that DEF acquire its plant is the most cost effective alternative to meet DEF's need prior to 2018, NRG's witnesses nowhere contest the economic value of the generation provided by the Hines Chillers Power Uprate Project and, in fact, NRG's witness Mr. Pollock proposes the acquisition of the NRG plant and the Hines Chillers Power Uprate project as an alternative, cost effective resource plan to simply acquiring the NRG plant to meet DEF's need prior to 2018. (Pollock Direct Test., p. 23, lines 25-26). Calpine's witnesses similarly argue that the Calpine July 3 proposal, the PPA with an option to purchase the Calpine Plant, is more cost effective than the Company's self-build generation projects to meet DEF's need prior to 2018 with a focus on the comparison of the Calpine generation proposal to the Suwannee Simple Cycle Project. (see, e.g., Thornton Direct Test., p. 15, lines 19-22; Hibbard Direct Test., p. 48, lines 9-12). But Calpine's witnesses concede as they must the economic value of the Hines Chillers Power Uprate project, explaining in their own simplistic cost analysis that the combination of the Calpine proposal and the Hines Chillers Power Uprate project is nearly equivalent to the Calpine proposal by itself. (Hibbard Direct Test., Exhibit No. ____ (PJH-3).

The apparent position of NRG and Calpine with respect to the Hines Chillers Power Uprate Project is consistent with my direct testimony and exhibits in this docket. As I explained there, the addition of the Hines Chillers Power Uprate Project to every generation capacity resource proposal made every proposal more economically favorable for DEF's customers, and therefore, our evaluation of the generation capacity resource proposals to meet DEF's need prior to 2018 included the Hines Chillers Power Uprate Project in every generation resource option. (Borsch Direct Test., p. 40, lines 17-23, p. 41, lines 1-3 and Exhibit No. ___ (BMHB-8). NRG and Calpine witnesses do not dispute this fact; in fact they both suggest the Hines Chillers Power Uprate Project as an alternative resource in addition to their generation capacity proposals, and the Calpine simplistic cost analysis supports the economic value of this Project for DEF's customers.

V. THE NRG AND CALPINE WITNESS CRITICISMS OF DEF'S EVALUATION OF THE MOST COST EFFECTIVE ALTERNATIVE TO MEET DEF'S NEED PRIOR TO 2018 ARE WRONG AND FAIL TO REFLECT AN UNDERSTANDING OF DEF'S IRP, EVALUATION PROCESS, AND SYSTEM REQUIREMENTS.

Q. Do the Calpine and NRG witnesses also criticize DEF's evaluation of the most cost-effective generation alternative to meet DEF's need prior to 2018?

A. Yes. Calpine witness Mr. Hibbard criticizes DEF's evaluation methodology and utility industry-standard resource planning cost models and, therefore, he rejects the results of DEF's evaluation. (Hibbard Direct Test., pp. 9-12, pp. 19-26). He argues that DEF should have used nothing more than a simplistic screening tool to determine the most cost effective generation alternative to meet its need prior to 2018 and, based on his application of that screening tool, he asserts that the Calpine plant is the most cost effective alternative to meet DEF's customer needs prior to 2018. (Hibbard Direct Test., p. 10, lines

6-10, p. 15). Mr. Hibbard's criticisms demonstrate, as I explain in detail below, that he does not understand the utility industry resource planning tools and models that DEF used in its evaluation of the most cost effective generation alternative to meet DEF's need prior to 2018. Further, his own simplistic levelized cost analysis demonstrates that the Suwannee Simple Cycle Project is the most cost effective generation resource to meet DEF's peaking need prior to 2018.

Alternatively, Mr. Hibbard accepts the CPVRR results of the Company's evaluation of the Calpine proposal compared to the Company's self-build generation projects to meet DEF's need prior to 2018 and he makes "adjustments" to those CPVRR calculations based on new inputs resulting from the July 3rd Calpine final and best offer. (Hibbard Direct Test., p. 27, lines 20-23, pp. 28-32). Mr. Hibbard fails to include all costs of the Calpine July 3rd final and best offer and he improperly removes proper costs, such as firm gas transportation costs, in his "adjusted" CPVRR analysis. These errors in Mr. Hibbard's analysis are explained above at pages 33-48 of my rebuttal testimony.

Mr. Hibbard, Mr. Thornton, and Mr. Pollock also criticize DEF's evaluation because they claim qualitative factors favor the Calpine plant or the NRG plant, respectively, rather than the Company's self-build generation projects to meet DEF's generation capacity need prior to 2018. In sum, they claim that, unlike the Company's self-build generation projects, the Calpine plant, or the NRG plant as the case may be, provides DEF customers price certainty, in-service date certainty, operating condition certainty and flexibility, and, in the case of the Calpine plant, better emissions because it is an existing combined cycle unit. (Hibbard Direct Test., p. 6, lines 6-23, p. 7, lines 1-8, p. 34, lines 20-23, pp. 35-36; Thornton Direct Test., p. 10, lines 13-23, pp. 11-13; Pollock Direct Test., p. 9, lines 11-22, pp. 10-11). These witnesses overstate the benefits and ignore the uncertainties associated with the Calpine plant or NRG plant, and the proposals to sell the plants to DEF.

Finally, Mr. Hibbard and NRG witness Mr. Pollock too criticize DEF's load forecast claiming it has errors or is inherently uncertain and, therefore, actual load conditions may deviate from projected load. (Hibbard Direct Test., p. 42, lines 21-22, p. 43; Pollock Direct Test., p. 21, lines 11-16, pp. 22-23). These criticisms are difficult to understand, not only because they are inaccurate, as I explain in detail below, but also because they seem to focus more on the need after 2018 rather than the Company's need that commences prior to 2018. In any event, to the extent these criticisms focus on the need prior to 2018 it is difficult to understand why both Calpine and NRG believe buying their existing units rather than building new generation units cures their claimed errors or uncertainty in the load forecasts.

NRG witness Mr. Pollock also criticizes DEF's evaluation while steadfastly maintaining that one aspect of DEF's evaluation demonstrates that the NRG initial plant acquisition proposal is more cost effective than the Company's self-build generation projects. I will demonstrate that he cannot "pick and choose" what he likes from the evaluation and discard the rest of the evaluation and explain why his recommendation based on part of that evaluation is simply wrong. In part this involves an explanation why his and NRG witness Mr. Dauer's assumptions that DEF can simply buy gas for the NRG plant the way NRG has done so as a merchant plant in the past fail to recognize DEF's obligation to reliably deliver power to customers during all hours, every day on its system. I will also demonstrate that Mr. Pollock fails to understand DEF's evaluation of the generation capacity resource options to meet DEF's need prior to 2018.

A. DEF'S GENERATION RESOURCE ALTERNATIVE EVALUATION.

Q. What are Mr. Hibbard's criticisms about the methodology and tools that DEF used to evaluate the generation resource alternatives to meet its need prior to 2018?

A. Mr. Hibbard criticizes the Company for, in his view, using <u>only</u> the Strategist resource planning model to determine the most cost effective generation alternative to meet DEF's need. (Hibbard Direct Test., p. 19, lines 19-23, p. 20, lines 1-11; p. 21, lines 11-23, p. 22, lines 11-23). He claims this Strategist model lacks transparency, does not adequately represent the value of different generation resource options --- such as a combined cycle unit and a CT unit ---- in the resource selection process, and is a simplistic rather than an hourly production cost dispatch model that unfairly understates the production cost benefit of the Calpine plant. (Id.). Mr. Hibbard claims that the appropriate production cost modeling tool that DEF should have used is a Ventyx or

General Electric "transmission-constrained, hourly production cost modeling program." (Hibbard Direct Test., p. 22, lines 3-9). In fact, as discussed below, DEF did use such a model in its evaluation.

Apparently because of his perceived problems with the Strategist model and his perception that DEF did not use an appropriate hourly production cost modeling tool, Mr. Hibbard argues that a levelized cost analysis is a more appropriate comparison of the Calpine plant to the Company's self-build generation project to meet the Company's need prior to 2018 and, that based on his levelized cost analysis, the Calpine plant actually is more cost effective than the Suwannee Simple Cycle Project to meet DEF's need prior to 2018. (Id.; p. 15).

Q. What modeling analyses were used by DEF in its evaluation of the alternative generation capacity resources to meet DEF's need prior to 2018?

A. DEF used all three types of modeling tools that Mr. Hibbard discusses in his direct testimony in its evaluation of the most cost effective supply-side alternatives to meet its need prior to 2018. DEF first applied an economic evaluation to screen "like type" proposals based on "the fixed and variable payments or costs." (Borsch Direct Test., p. 34, lines 18-22). This is similar if not identical to the "Levelized Cost of Electricity ("LCOE")" analysis that Mr. Hibbard describes in his direct testimony.

DEF next used the Strategist model to identify optimal resource plans corresponding to each proposal, including Calpine's proposal, and the self-build options. I explained the reasons DEF used the LCOE-type screening analysis and the Strategist optimization model in my direct testimony. The LCOE-type screening "compares the proposals to each other based simply on the cost of the proposals in isolation, the optimization analyses assessed the impact of each proposal on total system costs and compared those costs to the costs of the Company's base case self-build generation plan." (Borsch Direct Test., p. 36, lines 6-9). DEF, therefore, contrary to Mr. Hibbard's assertions did not rely only on the Company's Strategist analysis in its evaluation of the most cost effective generation resource to meet DEF's need prior to 2018. (Hibbard Direct Test., p. 19, lines 18-22).

DEF used the hourly-production cost model that Mr. Hibbard says DEF should have used in its generation resource evaluation. Mr. Hibbard asserts that DEF should have used "either Ventyx's Promod production cost modeling tool or General Electric's GE MAPS tool" because they are "transmission-constrained hourly production cost modeling programs." (Hibbard Direct Test., p. 22, lines 3-9). DEF used a Ventyx detailed production cost modeling tool --- DEF used the Energy Portfolio Manager ("EPM") detailed production cost model, which is a Ventyx production cost model of newer vintage than the Promod production cost model that Mr. Hibbard identifies in his direct testimony. The Ventyx EPM production cost model is a "transmission-constrained hourly production cost model program." I explain how we used

EPM to produce the CPVRR results for each proposal individually and then compared to the self-build projects in my direct testimony. (See Borsch Direct Test., p. 38, lines 12-23; pp, 39-40).

I can only conclude that Mr. Hibbard does not understand the use of production cost modeling in electric utility resource planning or, at the very least, how DEF uses these modeling tools in its resource planning and generation resource evaluations, or that he either did not read or simply chose to ignore my direct testimony, exhibits, and the discovery responses we have provided the parties explaining our evaluation.

Q. Is Mr. Hibbard's LCOE analysis a better tool to evaluate the most cost effective generation capacity resource alternative to meet DEF's need in 2018?

A. No. The LCOE analysis is a screening tool that should be used to compare "like type" generation resource options based on the fixed and variable payments that Mr. Hibbard identifies for the generation resources. This is exactly the way DEF used this screening tool in its evaluation. (Borsch Direct Test., p. 34, lines 18-20). In other words, this tool is used to compare CT proposals to other CT proposals, combined cycle proposals to combined cycle proposals, and so on, to narrow the number of resource options considered in the production cost modeling evaluation to the best of each type of option, i.e., the best CT proposal and the best combined cycle proposal and so on.

The LCOE analysis is not a good tool to compare different types of resource options, such as a CT proposal to a combined cycle proposal, because the LCOE analysis cannot tell you why you should pick one type of generation resource over another type of generation resource.

The LCOE analysis also does not help the utility understand the impact of adding any type of generation resource evaluated in the LCOE analysis to DEF's generation system. The LCOE analysis is not a dispatch model; it is a simple spreadsheet analysis that allows you to visually compare the costs of like type generation resources. To understand the impact of the generation resource option on DEF's system, DEF must evaluate the generation resource option in a production cost model that includes all generation system costs and dispatches the resource generation option in the most cost effective or economic dispatch for the generation system as a whole.

Mr. Hibbard acknowledges that this information regarding the economic dispatch of the generation resource option on DEF's generation system is the "key difference" between the LCOE analysis and a production cost model and that "production cost modeling can provide important insights and perspectives on resource operations and utilization over time, and on the likely value of resources on the system from an energy benefit perspective." (Hibbard Direct Test., p. 21, lines 11-14, lines 19-20). Mr. Hibbard simply criticizes the Strategist production cost model that DEF used only to identify the optimal resource plans for each alternative evaluated, ignores the Ventyx EPM hourly production cost model that DEF did use to obtain the admittedly "important insights and perspectives on resource operations and utilization over time" and "likely value" of resources from an "energy benefit perspective," and instead testifies that DEF should have used the LCOE analysis that provides none of these benefits.

Q. Do you agree with his criticisms regarding the Strategist model?

A. No. The Strategist model is a well-accepted utility industry production cost model that is used, for example, not only by DEF for resource optimization evaluations, but also by Gulf Power Company and the Southern Company utilities. Mr. Hibbard is correct that Strategist is not an hourly production cost model, and therefore, it necessarily is a more simplistic production cost model than a hourly production cost model like the Ventyx EPM hourly production cost model that DEF uses in resource planning. This, of course, is part of what makes the Strategist model a useful resource planning tool; it is more simplistic than an hourly production cost model and, therefore, with its flexible and powerful optimization engine, can be used more easily and in less time to evaluate optimal resource generation plans.

All of Mr. Hibbard's specific criticisms about the Strategist model --- beyond his vague claims that it is "opaque," "lacks transparency," and a "black box," which all mean the same thing (and with which I disagree) --- relate to the fact that the Strategist model is <u>not</u> an hourly production cost model. (Hibbard Direct Test., p. 22, lines 11-23, p. 23, lines 1-12). As I explained above, he does not know or he chooses to ignore that DEF also used the EPM hourly production cost model in its evaluation. Nowhere in his testimony does Mr. Hibbard criticize the EPM hourly production model – he in fact says DEF should use it --- nor does he criticize DEF's use of the EPM hourly production model in its evaluation of the generation resource options, including Calpine's proposal, to meet DEF's need prior to 2018.

Q. What do you make of Mr. Hibbard's criticism regarding the additional generation that is added to the DEF system in the Strategist model to meet the Reserve Margin requirement over the evaluation period?

A. It is difficult to understand Mr. Hibbard's criticism. He seems to say on page 23 that DEF is "building" more combined cycle generation than DEF needs to meet the annual growth in energy that he projects between 2018 and 2043, but then he expressly states on the next page of his direct testimony that he is not testifying that DEF is overbuilding combined cycle generation. (Hibbard Direct Test., p. 23, lines 13-23; p. 24, lines 15-17). I assume his point is that the only combined cycle generation that DEF should add to its system in this time period is Calpine's combined cycle generation plant. But, of course, if his point is that DEF is adding more combined cycle generation than DEF needs, then, DEF doesn't need the Calpine combined cycle generation plant either.

Mr. Hibbard's real concern is that, assuming DEF contracted for and acquired the Calpine plant in 2014, over time the capacity factor of the Calpine plant falls off and the number of starts increase for the Calpine plant as new, more efficient combined cycle generation is added to DEF's system. That is

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the point of Exhibit No. ___ (PJH-6). This means that new generation on DEF's system affects the cost effectiveness of the Calpine plant as a DEF generation system resource in the DEF resource evaluation. So Mr. Hibbard develops a chart comparing the projected energy growth on DEF's system to the projected growth in potential new combined cycle generation from 2018 to 2043 to claim that DEF doesn't need all the new combined cycle generation in its resource evaluation that is negatively affecting the value of Calpine's plant in the production cost dispatch analysis of the system. See Exhibit No. ___ (PJH-5). What Mr. Hibbard has done to create this apparent "overbuild" in future combined cycle generation capacity is to assume that <u>all</u> the existing and new combined cycle generation will <u>always</u> operate at a [redacted]. That assumption is obviously unrealistic and incorrect.

The whole point of resource planning is to add additional generation capacity when it is economic to do so to meet system reliability needs. Arbitrarily forcing the production cost model to run older, more costly to operate and maintain, and less fuel efficient units on the system will yield an overall more expensive system for customers than allowing the production cost model to select the most cost efficient resources even if that means adding new generation and reducing the operation of existing generation on the system. What Mr. Hibbard fails to mention is that the Calpine plant runs at a capacity factor of [redacted] from 2014 to 2026 in his own Exhibit No. ___ (PJH-6) when the Calpine plant is 10 to 22 years old. Of course, the Calpine plant operation will fall off when the plant is over 20 years old as new,

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more fuel efficient generation units are added to the system. DEF's existing, older generation units on the system are not immune from these effects, the same thing happens to the capacity factor and number of starts for DEF's existing combined cycle generation.

Q. You testified that the LCOE analysis that Mr. Hibbard recommends should only be used to compare "like type" resources. Does Mr. Hibbard use the LCOE analysis to compare "like type" resources?

A. No. Mr. Hibbard uses his LCOE analysis to compare combined cycle generation – the Calpine plant – to CT generation --- the Suwannee Simple Cycle Project. It should not surprise anyone in the utility industry that combined cycle and CT generation have different capital, fixed and variable operation and maintenance ("O&M"), and other costs and different capacity factors. Using the LCOE analysis to make a selection between these two different resource options is not a meaningful exercise to determine which generation option is the most cost effective generation on DEF's system.

Mr. Hibbard's Exhibit No. ___ (PJH-3) illustrates this point. According to Mr. Hibbard, Exhibit No. ___ (PJH-3) demonstrates that the Calpine asset sale at $85.3 ($2014/MWh) is more cost effective than the DEF Suwannee Simple Cycle Project at $168 ($2014/MWh). But Mr. Hibbard is comparing the Calpine asset sale value at a [redacted] capacity factor to the value of the Suwannee Simple Cycle Project at a 9.3 percent capacity factor, which is the expected capacity factor for the Suwannee Simple Cycle Project. See Exhibit

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No. ___ (PJH-4). If Mr. Hibbard is suggesting that DEF should always compare combined cycle generation costs on a $/MWh basis at a [redacted] capacity factor to CT generation on a $/MWH basis at a roughly 9 percent capacity factor, then, DEF --- or any other public utility for that matter --- will always select the combined cycle generation over the CT generation. Since this will never be the case in the real world where DEF and every other public utility will build generation to meet base, intermediate, and peaking load the LCOE analysis is clearly a meaningless exercise when the utility must determine what type of generation is the most cost effective generation on its system.

Q. Based on DEF's actual system need prior to 2018, does Mr. Hibbard's LCOE analysis tell you anything about the most cost effective generation resource to meet that need?

A. It could be read this way. DEF identified a peaking generation need prior to 2018 and that is why the production cost model evaluations in DEF's IRP process identified the Suwannee Simple Cycle Project in 2016. Based on DEF's need for peaking generation on its system prior to 2018, Mr. Hibbard's own exhibit demonstrates that the Suwannee Simple Cycle Project is more cost effective than the Calpine plant. On Exhibit No. ___ (PJH-4), at any capacity factor below [redacted], the Suwannee Simple Cycle Project is more cost effective on a $/MWh basis than the Calpine plant. At the expected capacity factor of 9.3 percent for the Suwannee Simple Cycle Project, then, the Company's self-build peaking generation resource is much more cost effective than the Calpine plant.

This is an expected result. Mr. Hibbard admits that "CT capacity is effective providing capacity at times of system peak or otherwise when stressed system conditions require operation of peaking capacity." (Hibbard Direct Test., p. 38, lines 18-20). If DEF needs generation capacity to meet system peak load, then, Mr. Hibbard admits that CT generation like the Suwannee Simple Cycle Project is the effective capacity to meet that need.

In fact, this exactly demonstrates the weakness of LCOE as a stand-alone evaluation methodology. If the analysis assumes a particular use or capacity factor for a given unit, then, the LCOE will almost always support the selection of a unit designed for that service. A more detailed production cost model such as EPM will re-dispatch resources to allow different resources to operate at an optimum capacity factor in the context of the whole portfolio. This allows comparison of different types of resources in light of their impact on the total production cost.

Peaking generation capacity is an effective addition to the DEF fleet prior to 2018. Calpine witness Mr. Thornton is wrong when he says DEF is replacing base load generation due to the retirement of CR3 and the near-term retirement of CR1 and CR2. (Thornton Direct Test., p. 12, lines 8-11). DEF is replacing base load and intermediate generation due to the CR3 retirement and the planned CR1 and CR2 retirement with the Citrus County Combined Cycle Power Plant that is the subject of DEF's Petition in Docket No. 140110-

EI. Prior to the addition of the Citrus County Combined Cycle Power Plant in 2018, the Company can effectively utilize peaking generation capacity and that is why DEF identified the Suwannee Simple Cycle Project as the most cost effective self-build generation capacity option in 2016.

Q. If DEF needs peaking generation capacity prior to 2018, why did DEF consider the Calpine proposal in its evaluation?

A. DEF is always looking for the best overall value for its customers. Even though DEF had identified a peaking generation capacity need prior to 2018, and the Suwannee Simple Cycle Project to meet that need in 2016, DEF would have considered any alternative generation capacity resource option that offered more overall value to customers than the Company's peaking generation self-build option, including the Calpine proposal. As in all comparisons between combined cycle and peaking units, the combined cycle must provide enough operating cost savings in the context of the whole fleet to offset the higher capital cost of the combined cycle. In our evaluation in this case, however, Calpine's reduced acquisition price closed part of, but not all of, the gap between its revised July 3rd offer and the Company's self-build generation, thus, the Suwannee Simple Cycle Project remains the most cost effective generation resource option to meet DEF's need in 2016.

B. DEF REASONABLY CONSIDERED THE QUALITATIVE FACTORS OF ALL PROPOSALS TO MEET DEF'S NEED PRIOR TO 2018.

Q. Mr. Hibbard, Mr. Thornton, and Mr. Pollock all claim that DEF did not appropriately evaluate the qualitative value that their existing Calpine and NRG plants, respectively, provide. Do you agree with them?

A. No. DEF does not understand their claim that DEF did not evaluate these factors in its evaluation. DEF did consider these factors in its evaluation. They are included in Exhibit No. ___ (BMHB-9) and discussed in my direct testimony. (Borsch Direct Test., pp. 41-42 and 46-48). These witnesses simply do not like the fact that this analysis also included qualitative risks associated with the Calpine and NRG proposals and they do not like the results of DEF's evaluation of all the qualitative factors or risks, including the qualitative factors or risks associated with the Calpine and NRG acquisitions. (Id.).

The undisputed fact that the Calpine and NRG plants currently exist and the Suwannee Simple Cycle Project must be built does not render their projects qualitatively more favorable than the Suwannee Simple Cycle Project. First, with respect to the construction and in-service date risk, the cost of the Suwannee Simple Cycle Project accounts for these risks. (Borsch Direct Test., p. 41, lines 5-11; Exhibit No. ___ (BMHB-9)). Second, DEF knows how to build and has built similar projects to the Simple Cycle Project on time and on budget. See Exhibit No. ___ (BMHB-19) to my rebuttal testimony. Finally, DEF further has made it clear in this Docket that, given the unique circumstances of this Petition, DEF accepts the fact that it will be bound by the cost estimate of its self-build projects unless DEF can demonstrate that any cost increase was prudent and point to specific reasons to justify the increase.

In addition, there is no greater price certainty associated with the Calpine and NRG proposals, despite their claims to the contrary. Many terms affecting the price of the plant acquisitions remain to be negotiated with both final and best offers. For example, Mr. Thornton admits the Calpine purchase price was "subject to certain adjustments the terms of which would be negotiated." (Thornton Direct Test., p. 8, lines 15-17).

Likewise, there is substantial uncertainty with respect to the plant condition and operational capability of both plants under both the Calpine and NRG final and best offers. Both Calpine and NRG tout the past performance and operational capabilities of their plants, but past performance is no guarantee of future plant performance, and DEF was buying both plants under their final and best offers in the future. At that future point in time, there were no guarantees of performance and terms addressing the condition of the plant in the final and best offers, and the rights of the parties based on the plant condition at that future point remained undetermined and, thus, uncertain. (See Exhibits Nos. ____ (BMHB-12) and ___ (BMHB-13).

In sum, despite the fact that the Calpine and NRG plants currently exist, there remain unknown terms and conditions associated with their final and best offers for those existing plants that make it clear that the claimed price and operational performance certainty that the Calpine and NRG witnesses tout simply do not exist. There is no reason to believe that these unknown terms and conditions associated with their final and best offers are qualitatively less risky to the Company than completing the construction of a standard CT plant much like Duke Energy has done many times before.

C. DEF'S LOAD FORECAST IS REASONABLE AND DEMONSTRATES DEF'S NEED FOR ADDITIONAL GENERATION CAPACITY PRIOR TO 2018.

Q. You testified that the NRG and Calpine witness testimony with respect to DEF's load forecast is difficult to understand. Can you explain what you mean?

A. NRG witness Mr. Pollock and Calpine witness Mr. Hibbard to a lesser degree criticize DEF's load forecast and resource plan to meet that load in their direct testimony. (Hibbard Direct Test., p. 42, lines 21-22, p. 43; Pollock Direct Test., p. 21, lines 11-16, pp. 22-23). NRG and Calpine filed this direct testimony in this Docket and in Docket 140110-EI, which involves DEF's Petition for Determination of Need for the Citrus County Combined Cycle Power Plant in 2018. While unclear, NRG witness Mr. Pollock and Calpine witness Mr. Hibbard in part of their direct testimony appear to be addressing DEF's need in 2018 and beyond, and, as a result, I have filed rebuttal testimony in Docket 140110-EI addressing this part of their direct testimony. Indeed, one reason I am unclear if these witnesses intended to direct this part of their testimony to DEF's need prior to 2018 is that they both claim that DEF should have selected their acquisition proposals and buying their existing plants to add generation capacity rather than building new generation capacity still does not cure any claimed errors or uncertainty in DEF's load forecast. To the extent that Mr. Pollock or Mr. Hibbard are asserting these arguments in this Docket, I am providing the same rebuttal testimony to these arguments below that I provided in Docket No. 140110-EI in this Docket.

Q. Do the NRG and Calpine witnesses claim that there are errors in DEF's load forecast or load forecast methodology?

A. NRG witness Mr. Pollock appears to claim there is a load forecast error affecting DEF's generation capacity needs, but Calpine witness Mr. Hibbard does not claim there are errors in DEF's load forecast or load forecast methodology. (Pollock Direct Test., pp. 21-22). In fact, Calpine witness Mr. Hibbard specifically says that he did not find anything wrong with DEF's forecasts of load/energy growth or the timing of resource additions or retirements. (Hibbard Direct Test., p. 42, lines 21-22, p. 43, line 1). He admits there will be growth in peak load and energy requirements. (Hibbard Direct Test., p. 43, lines 3-4). Ironically, despite apparently claiming an error in DEF's load forecast, NRG witness Mr. Pollock also concedes it is also possible that load growth could be higher than what DEF projects in its load forecast. (Pollock Direct Test., p. 23, lines 6-9). Both witnesses were provided the same DEF load forecast.

Q. What is the load forecast error that NRG witness Mr. Pollock apparently asserts occurred in DEF's load forecast?

A. NRG witness Mr. Pollock asserts that DEF's need for capacity prior to 2018 is driven primarily by a more than 1,000MW increase in both wholesale and peak demand in 2014-2015. He then claims that, because DEF has not actually experienced such significant load growth in any two years since 2005, there is some unasserted reason to believe there may be a risk of load forecast error in DEF's load forecast. Based on this belief, NRG witness Mr. Pollock assumes an arbitrary 50 percent reduction in DEF's load forecast and develops an argument and exhibits to support his unremarkable conclusion that DEF would not need its planned capacity additions in the 2014 to 2023 time frame if you assumed DEF's load was half of what DEF projects it to be in this time frame. (Pollock Direct Test., p. 21, lines 11-16, p. 22, lines 1-21, Exhibit Nos. ___ (JP-2) and ____(JP-3).

Q. Is there an error in DEF's load forecast?

A. No. NRG witness Mr. Pollock selectively chooses the years in DEF's load forecast to focus on to generate his claimed greater than 1,000MW increase in 2014-2015 that, according to him, is out of line with DEF's load growth for the last ten years. A more comprehensive evaluation of DEF's load forecast demonstrates that there is no such dramatic deviation in DEF's load forecast and that any deviations that do exist are readily explained by changes in DEF's wholesale contracts and retail load during the period selected by Mr.

Pollock. In addition, Mr. Pollock chooses as his reference the actual firm generation peak, net of all load control, for 2013, which was a milder than average summer, and then compares that to the 2014 and 2015 projected total, which are necessarily based on normal weather.

DEF's load forecast is contained in the Company's 2014 Ten Year Site Plan ("TYSP") attached as Exhibit No. ____ (BMHB-2) to my direct testimony. True, based on that load forecast in Schedule 3.1, there is a greater than 1,000MW increase in the net firm demand from 2013 to 2015. But, there is a relatively negligible increase of approximately 100MW in net firm demand from 2010 to 2015. It matters, then, what years you choose to compare in the Company's load forecast as to what conclusions you may draw from the forecast and when comparing actual past years to projected future years what the actual weather conditions were.

Further, the claimed dramatic changes in the load forecast that NRG witness Mr. Pollock claims exist based on the years he selected to compare can be explained in part by changes in the Company's wholesale power contracts during this period of time and the comparison between actual wholesale load and DEF's future commitments.

Additionally, DEF is projecting an increase in retail load from 2013 to 2014 as the Florida economy continues to improve and DEF continues to add customers. This projected increase in retail demand from 2013 is only 200MW greater than the increase in retail load DEF actually experienced from 2012 to 2013 as the Florida economy was just starting to improve after the recession and customer growth was expanding. This continued retail load growth in 2014 and 2015 is certainly reasonable based on what DEF experienced from 2012 to 2013 and what is projected to occur as the Florida economy continues to improve. Again, Calpine witness Mr. Hibbard reviewed the same load forecast and found nothing wrong with the Company's load forecast. (Hibbard Direct Test., p. 42, lines 21-22, p. 43, line 1). And, as I explained above, NRG witness Mr. Pollock himself admits it is possible load growth could be higher than DEF forecasts it to be. (Pollock Direct. Test., p. 23, lines 6-9).

Q. Is there any reason to conclude from DEF's load forecast as NRG witness Mr. Pollock does that there could be a 50 percent reduction in DEF's load growth during the next ten years?

A. No. As I explained above, Mr. Pollock's claimed potential "error" based on his selective reading of DEF's load forecast is not an "error" at all. Even apart from this assertion by Mr. Pollock, however, there is no reasonable basis that I can see for Mr. Pollock to assume a 50 percent reduction in DEF's load growth and he provides none in his direct testimony. He appears to simply have arbitrarily selected 50 percent as his projected reduction in DEF's load forecast in order to make a point. He may draw as many bar charts as he likes showing that if you reduce DEF's projected load growth by 50 percent it results in 50 percent excess capacity, but that result, of course, naturally flows from his arbitrary assumption that there is a 50 percent reduction in DEF's projected load. (Pollock Direct Test., Exhibit Nos. ___ (JP-2) and ____ (JP-3).

Q. If Calpine witness Mr. Hibbard found no errors in DEF's load forecast what does he say the Commission should do with DEF's load forecast?

A. While Mr. Hibbard expressly says he is not suggesting that the Commission "second-guess" the Company's planning efforts (Hibbard Direct Test., p. 43, line 5), that is, in effect, exactly what he asks the Commission to do. He argues the Commission should "provide flexibility around the timing of the" Citrus County Combined Cycle Power Plant because he says he has recognized, "based on his decades of experience as a utility regulator and consultant," that load forecasts are based on assumptions and actual load will almost certainly deviate from the prior assumptions about that load. (Hibbard Direct Test., p. 43, lines 6-10). He claims that the one resource that provides the Commission this "needed flexibility" around the timing of the Citrus Combined Cycle Power Plant that he identifies in his testimony is the Company's acceptance of Calpine's proposal for a PPA with a purchase option to meet the Company's need prior to 2018. (Hibbard Direct Test., p. 43, lines 17-23).

Q. Does Mr. Hibbard identify any error in the assumptions in DEF's load forecast or any assumptions that he believes based on his decades of experience should be changed?

A. No. He in fact said there was nothing wrong with the Company's load forecast or the timing of its resource additions and retirements. (Hibbard Direct Test., p. 42, lines 21-22, p. 43, line 1). That must mean Mr. Hibbard finds nothing wrong with the timing of the Suwannee Simple Cycle Project, the Hines Chillers Power Uprate Project, or the Citrus County Combined Cycle Power Plant.

Mr. Hibbard does refer to the discussion of the accuracy of the utility retail load and energy sales forecast in the Commission's review of the 2013 TYSPs, but it is unclear what he intends the Commission to do with this information. It is hardly surprising that the absolute average error in retail energy sales has increased in "recent years" when Florida has experienced the worst recession since the Great Depression during those years. (Hibbard Direct Test., p. 43, lines 10-12). DEF and other utilities have struggled along with all economic forecasters to properly anticipate the length of the recession and the timing and rate of the recovery. Mr. Hibbard does not suggest that the Commission do anything with this information, and rightly so, because such aberrational economic conditions cannot be accurately predicted and certainly should not be included as an appropriate assumption for a utility's annual load forecasts.

Mr. Hibbard also notes that the "best" forecasts -- which include the Company's load forecasts -- have proven to be accurate to within 1 to 3 percent a year. (Hibbard Direct Test., p. 43, lines 12-16). DEF agrees that it has a demonstrated record of load forecast accuracy. Mr. Hibbard incorrectly concludes, however, that the minor deviations in the accuracy of the annual utility load forecasts can be compounded over several years, thus, leading to significant variations in actual demand. Mr. Hibbard ignores the fact that utilities, including DEF, update their load forecasts regularly, including each year in the utility TYSP. If reasons exist to deviate from prior year forecasts, the load forecasts will be revised, and therefore, there is no statistical or reasonable basis to conclude that prior year deviations in load forecast accuracy can simply be summed up or compounded to determine the overall accuracy of the utility's load forecast. Exhibit No. ___ (BMHB-20) to my rebuttal testimony shows DEF's summer load forecasts over the last six years. This Exhibit shows that DEF updates its load forecast to anticipate the duration and recovery from the recession as well as other trends in expected demand.

In sum, then, his apparent contention that the Commission should simply depart from the assumptions in the Company's load forecasts and the Company's planned generation capacity additions to meet that projected load in DEF's resource plan because actual load conditions in the future may deviate from the assumed load conditions is unprincipled resource planning. The same assertion could be made to justify any deviation anyone wants to make from every single utility load forecast and resource plan because no forecast is absolutely accurate and actual conditions will always deviate to some degree from forecasted conditions. Despite the fact that actual load may be different from what DEF projects it to be DEF must still plan to meet that future load based on reasonable assumptions about future load conditions and resources to meet that load. That is the very nature of DEF's IRP process that is presented to the Commission each year in the utility TYSP and reviewed by the Commission to determine if it is suitable for planning purposes. Mr. Hibbard has not identified any error in that IRP process or any principled resource planning reason for the Commission to deviate from the Company's conclusions based on that IRP process.

D. NRG IS INCORRECT THAT THE NRG ACQUISITION 1 PROPOSAL IS MORE COST EFFECTIVE THAN THE COMPANY'S SELF-BUILD GENERATION PROJECTS.

Q. Can you summarize the position of NRG's witnesses in this Docket?

A. Yes. NRG witness Mr. Pollock, and NRG witness Mr. Dauer too apparently, argue that DEF should have selected the NRG plant acquisition --- the Acquisition 1 proposal --- that NRG submitted in response to the Company's fall 2013 request for renewed proposals to meet DEF's 2018 need. (Pollock Direct Test., p. 6, lines 18-21; Dauer Direct Test., p. 3, lines 4-10). This is the same proposal that DEF evaluated against its Suwannee Simple Cycle Project and Hines Chillers Power Uprate Project and determined, based on all quantitative and qualitative factors, was not a more cost effective resource than the Company's self-build generation projects to meet DEF's need prior to 2018. (Borsch Direct Test., pp. 33-48).

Q. Is the NRG Acquisition 1 proposal NRG's final and best offer?

A. No, it is not. NRG's final and best offer is included as Exhibit No. ___ (BMHB-14) and the Company's evaluation of the NRG final and best offer is included as Exhibit No. ___ (BMHB-15) to my rebuttal testimony. I address NRG's final and best offer in my rebuttal testimony above.

NRG witnesses Mr. Pollock and Mr. Dauer do not describe or even mention NRG's final and best offer in their direct testimony. They do not recommend NRG's final and best offer to the Commission --- they in fact recommend NRG's earlier Acquisition 1 proposal and argue that DEF should have selected the Acquisition 1 proposal. The Acquisition 1 proposal is <u>less</u> cost effective than NRG's final and best offer compared to the Company's self-build projects. In other words, NRG witnesses argue that DEF should have selected NRG's <u>least</u> cost effective proposal.

Q. If the NRG Acquisition 1 proposal was not more cost effective than the Company's self-build generation projects, why do the NRG witnesses argue that DEF should have selected it to meet DEF's need prior to 2018?

A. NRG witness Mr. Pollock at first focuses <u>solely</u> on <u>part</u> of DEF's economic analysis, its <u>initial</u> detailed economic analysis, and claims that this analysis demonstrates that the NRG Acquisition 1 proposal was the most cost effective generation capacity resource to meet DEF's need prior to 2018. (Pollock Direct Test., p. 8, lines 7-17). DEF's <u>initial</u> detailed economic analysis did show that the NRG Acquisition 1 proposal was marginally more cost effective than the Company's Suwannee Simple Cycle Project, but essentially equivalent on a CPVRR basis over the 30-year study period. (Borsch Direct Test., p. 40, lines 4-15; Exhibit No. ___ (BMHB-8)).

This was not the end of DEF's evaluation, however, DEF went on to the next steps in its evaluation which included the cost risk sensitivities analyses, its final detailed economic evaluation, and its qualitative analyses, which included the FERC Competitive Analysis Screen. (Borsch Direct Test., pp. 41-48; Exhibit No. ___ (BMHB-9). Based on the complete evaluation of the NRG Acquisition 1 proposal and other generation capacity proposals, DEF concluded that the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project are the most cost effective alternatives to meet the Company's need in 2016 and 2017.

Q. Do the NRG witnesses argue that the NRG Acquisition 1 proposal should be selected over other resource options based only on the initial detailed economic analysis?

A. No. Despite contending that the NRG Acquisition 1 proposal is the most cost effective option based solely on DEF's initial detailed economic analysis, NRG witness Mr. Pollock agrees that the NRG Acquisition 1 proposal should not be selected simply because it is less expensive over the 30-year period than other resource options in the Company's initial detailed economic analysis. (Pollock Direct Test., p. 11, lines 8-11). He concedes the "cost-effectiveness analysis should not be the sole deciding factor" and that "the Commission should use qualitative criteria in addition to the quantitative cost-effectiveness analysis to determine the resources best suited for meeting DEF's" need. (Pollock Direct Test., p. 11, lines 17-18, lines 23-24). Mr. Pollock ignores, however, most of the qualitative factors that led DEF not to select the NRG Acquisition 1 proposal, many of which DEF asked NRG to address in its final and best offer. These factors are listed on page 47 of my direct testimony.

Q. What factors does Mr. Pollock focus on in his direct testimony?

A. Mr. Pollock makes four claims. First, he claims DEF over-stated the fixed costs associated with the firm gas transportation for the NRG plant in DEF's evaluation of the Acquisition 1 proposal. This is the primary cost risk associated with the NRG Acquisition proposal and addressed in Exhibit No. ___ (BMHB-9) to my direct testimony that rendered the Acquisition 1 proposal uneconomic. Second, Mr. Pollock claims that DEF misapplied the FERC Competitive Analysis Screen in eliminating Acquisition 1 as a viable alternative. Third, Mr. Pollock claims that DEF improperly included imputed debt as a cost in its detailed economic evaluation. Finally, Mr. Pollock argues that DEF did not account for the qualitative benefits of price and operational performance certainty provided by the existing NRG plant. I already addressed this argument in my rebuttal testimony above.

Q. Did DEF over-state the fixed costs associated with the firm gas transportation for the NRG plant?

A. No. Mr. Pollock argues that DEF ignored the existing fuel supply arrangements for the NRG plant in its evaluation but defers to NRG witness Dauer to explain these arrangements. (Pollock Direct Test., p. 10, lines 10-14). Not only did we not ignore these existing fuel supply arrangements in our evaluation of Acquisition 1, we were much very aware of the inadequacies of these arrangements to meet DEF's needs for a system of this type, and had identified this as the principle cost risk associated with the NRG plant acquisition. (Borsch Direct Test., p. 41, lines 14-22; Exhibit No. ___ (BMHB-9). Simply put, if DEF acquired the NRG plant DEF must have sufficient firm gas transportation for all of the plant's capacity to meet peak load needs, otherwise, I could not designate the NRG plant as firm power to meet DEF's Reserve Margin requirements. DEF, unlike NRG, has a statutory obligation to reliably provide electric service to its customers.

I have read Mr. Dauer's direct testimony and it only confirms my concerns with NRG's proposed firm gas transportation for the NRG plant. Mr. Dauer makes no attempt to understand DEF's need as a public utility with a statutory obligation to provide electric service to customers for firm gas transportation for the plant on DEF's system. Rather, Mr. Dauer relies on NRG's past experience operating the NRG plant as an Independent Power Producer. NRG's past experience is no guarantee of the future operation of the plant and DEF is a public utility, not an Independent Power Producer.

Mr. Dauer argues that NRG has managed to obtain gas on a non-firm or spot market basis, at an unspecified price, when NRG needed it to meet the power needs of another utility with different system requirements. (Dauer Direct Test., pp. 5-10). Mr. Patton provides rebuttal testimony to explain DEF's firm gas transportation requirements and why Mr. Dauer's past NRG experience is not an adequate future plan for DEF if it acquired the NRG plant. I can add as the director of resource planning for DEF that I am not prepared to "gamble" on non-firm gas transportation on the market being available at a reasonable price for customers at peak hours when the plant is most needed.

Q. Does Mr. Pollock explain his claim that the Company misapplied the FERC market screen?

A. No. Mr. Pollock defers to NRG witness Dr. Morris. Julie Solomon has filed rebuttal testimony to Dr. Morris' direct testimony. I can add, however, that the NRG Acquisition 1 proposal that Mr. Pollock recommends was analyzed by Ms. Solomon and Ms. Solomon determined that it failed the FERC Competitive Analysis Screen. Neither Mr. Pollock nor Dr. Morris disputes that analysis.

Q. Did DEF improperly include imputed debt in its economic evaluation of the NRG Acquisition 1 proposal?

A. No. The NRG Acquisition 1 proposal that NRG witness Mr. Pollock says DEF should have selected is, as indicated by the name of the proposal, a plant acquisition proposal. There is no imputed debt cost for a plant acquisition.

In addition, while the cost of imputed debt is typically applied to PPA proposals to ensure that the total costs of the PPA proposals include the marginal impact of the fixed future commitment on DEF's capital structure as a result of the fixed future payment obligations under the PPA, I explained that, in this case, because the PPA terms were all five years or less, the impact of imputed debt was immaterial. (Borsch Direct Test., p. 39, lines 15-23, p. 40, lines 1-2). As a result, the cost of imputed debt was not included in the final detailed economic analysis for even the PPAs that were evaluated.

Q. Does Mr. Pollock make any additional arguments in support of the NRG Acquisition 1 proposal?

A. Yes. Mr. Pollock makes an extended argument regarding DEF's customer rates. This argument is irrelevant in this proceeding. The Commission will determine in this proceeding if DEF has demonstrated the most cost effective generation capacity resource to meet its need for generation capacity prior to 2018. The customer price impacts as a result of the most cost effective generation resource to meet the need for generation capacity prior to 2018 will be what they will be. The point is, if DEF had demonstrated a need for generation capacity prior to 2018 --- which is uncontested by any NRG or Calpine witness in this Docket --- then the decision in this Docket is what is the most cost effective generation to meet that need for generation capacity.

VI. CONCLUSION.

Q. Have the NRG or Calpine witnesses presented any evidence that their recommended generation capacity resources to meet DEF's need for

generation capacity prior to 2018 are more cost effective alternatives to meet the Company's reliability needs in the summers of 2016 and 2017?

A. No. The Company evaluated market proposals for alternative generation to meet its need for generation capacity in the summers of 2016 and 2017 --- including NRG and Calpine PPA and plant acquisition proposals --- and the Company determined, for the reasons provided in my direct testimony, that the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project were more cost-effective, on a quantitative and qualitative basis, than any of the alternative supply-side generation proposals. The NRG and Calpine witness testimony in this Docket does not change this determination.

To begin with, no NRG or Calpine witness directly challenges the cost-effectiveness of the Hines Chillers Power Uprate Project as a generation capacity resource to meet DEF's reliability need in the summer of 2017. Their testimony focuses on the comparison of their generation capacity proposals to the Suwannee Simple Cycle Project. It is undisputed, then, that the Hines Chillers Power Uprate Project is the most cost effective generation capacity resource to meet DEF's reliability need in the summer or 2017.

Calpine and NRG both submitted final and best offers after DEF filed its Petition and direct testimony and exhibits in this Docket because they obviously recognized their initial generation capacity proposals proved to be less cost effective than the Suwannee Simple Cycle Project. These proposals moved closer to the cost effectiveness of the Suwannee Simple Cycle Project, but they still were not more cost effective than that Project to meet DEF's need for generation capacity in the summer of 2016.

Calpine continued to press the cost effectiveness of its final and best offer in its Direct Testimony in this Docket. Calpine's primary expert witness Mr. Hibbard deliberately ignores or does not understand DEF's evaluation models and tools, criticizes DEF for not employing production cost economic dispatch models that DEF in fact employed, and urges the Commission instead to use his results from a simplistic screening tool for "like type" resources to evaluate different types of resources without understanding the costs and benefits of the dispatch of the resource on DEF's system. This is not a detailed economic analysis of the proposals or a fair and accurate criticism of DEF's detailed economic analysis of the alternative generation resource options to meet its reliability need commencing in the summer of 2016. That detailed economic analysis, which includes an analysis of the economic dispatch of the alternative resources on DEF's system using the very model Mr. Hibbard said DEF should use, demonstrates that DEF has a need for peaking generation capacity in the summer of 2016 and that the Suwannee Simple Cycle Project is the most cost effective generation capacity resource to meet that need. Even the simplistic screening tool Mr. Hibbard used demonstrates that, if peaking generation capacity is needed, the Suwannee Simple Cycle Project is more cost-effective to meet that need than the Calpine plant.

NRG retreated from its final and best offer to its initial plant acquisition proposal. On a quantitative and qualitative basis, which NRG witness Mr. Pollock agrees is the right evaluation approach, the initial NRG plant acquisition is not more cost effective than the Suwannee Simple Cycle Project. Firm natural gas transportation at all times for all the plant's capacity is an absolute necessity for DEF to rely on this plant as a firm resource to meet DEF's obligation to provide reliable electric service at all times to its customers. DEF simply cannot and will not "gamble" on natural gas transportation being available at a reasonable price on the spot market when DEF needs that plant to reliably serve its customers in the manner that NRG as an Independent Power Producer with no obligation to serve has operated the NRG plant in the past. Further, the NRG plant acquisition fails the FERC Competitive Analysis Screen, preventing DEF from acquiring the NRG plant. No NRG witness disputes the fact that the initial plant acquisition failed the FERC market screen that must be passed to obtain FERC approval for the acquisition.

In sum, the Suwannee Simple Cycle Project is the most cost effective generation capacity resource, on a quantitative and qualitative basis, to meet DEF's need for generation capacity commencing in the summer of 2016. The Suwannee Simple Cycle Project is a new, state-of-the-art CT plant with higher fuel efficiency than existing CT plants located at an existing DEF power plant site where it benefits from the shared resources and further provides transmission stability in the area. It is the most beneficial generation capacity resource to meet DEF's peaking generation capacity needs commencing in the summer of 2016.

For all these reasons, and the reasons provided in DEF's Petition and direct testimony and exhibits in this Docket, DEF requests that the Commission grant DEF's Petition and approve the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project as the most cost effective generation alternatives to meet the Company's need in 2016 and 2017.

Q. Does this conclude your rebuttal testimony?

A. Yes.

BY MR. WALLS:

Q Mr. Borsch, would you please provide a summary -- oh, I guess, do you have a summary of your prefiled direct and rebuttal testimony?

A I do.

Q Would you please provide the Commission with a summary of both your prefiled direct and your prefiled rebuttal testimony at this time.

A Good morning, Commissioners. I am the Director of Integrated Resource Planning and Analytics for Duke Energy Florida. I'm testifying today on behalf of Duke Energy Florida in support of its Citrus County combined cycle power plant and the Hines uprate project.

Regarding the Citrus County combined cycle, DEF needs additional generating capacity in 2018 to reliably serve its customers. The company identified the Citrus County combined cycle power plant to meet this reliability need after conducting a careful screening of various supply-side alternatives and additional renewable energy resources and conservation measures in its resource planning process.

The Citrus County combined cycle is a highly efficient state-of-the-art natural gas-fired combined cycle generation plant located on a favorable site in Citrus County. I conducted the company's request for proposal, and after a thorough evaluation of the bids received we determined that the Citrus County combined cycle is the most cost-effective option to met DEF's 2018 need.

Regarding the Hines uprate project, DEF needs this project by the summer of 2017 to serve its customers' future electrical power needs in a reliable and cost-effective manner. The Hines chiller power uprate project was superior to any other alternative, including additional renewable resources and conservation measures, to meet the company's near-term generation capacity needs.

I have also filed rebuttal testimony in both dockets regarding the Citrus County combined cycle power plant. My rebuttal testimony addresses testimony filed by witnesses for both NRG and Calpine.

None of these witnesses dispute that the Citrus County combined cycle is a reliable, cost-effective generation capacity resource addition to DEF's generation system. They do not dispute that the Citrus County combined cycle is the most cost-effective generation to meet the company's need commencing in 2018 if the company needs that generation resource in 2018.

What they challenge in this docket is whether there is a need for the Citrus County combined cycle in

2018. NRG witness Mr. Pollock hypothesizes load forecast errors that do not exist and arbitrarily projects a 50 percent reduction in DEF's load growth, resulting in an equally arbitrary 50 percent excess capacity to suggest that the plant is not needed in 2018. He presents no analysis to support these projections.

Calpine witness Mr. Hibbard says that he found no load forecast errors in the same DEF load forecast, but he argues that actual load conditions may deviate from projected load, relying on such unusual conditions as the Great Recession to suggest that the plant could be deferred a year until 2019. Both arguments are not only inaccurate but would, if accepted, allow anyone to argue for any deviations they want in a utility's load forecast and resource plan. This is not prudent resource planning.

Mr. Hibbard further suggests that DEF customers could benefit from the deferral of the Citrus County combined cycle if DEF accepts Calpine's proposal and extends Crystal River Units 1 and 2 for another year rather than retiring them in 2018 as the company plans. Mr. Hibbard is wrong.

First, DEF needs the Citrus County combined cycle in 2018, irrespective of which of the proposed options is selected to meet its need in 2018. Second, there is an additional cost of $90 million to customers if Citrus -- if Crystal River Units 1 and 2 are extended, and there are reliability and environmental risks for extending those units.

In sum, NRG and Calpine provide no principled reason to defer the Citrus County combined cycle plant. So the company requests that the Commission grant its petition so that DEF can provide the benefits of this plant to its customers.

I also filed rebuttal testimony to address NRG witnesses regarding DEF's Hines chiller power uprate project. NRG does not dispute the company's reliability need for generation capacity prior to 2018. Rather, they argue that the company should have selected their generation capacity proposals rather than that -- well, rather than the Suwannee project to meet the company's need. No witness directly challenges DEF's testimony that the Hines chiller power uprate project is cost-effective for customers.

This concludes the summary of both my testimonies, and I'm happy to answer any questions that you may have. Thank you.

(Transcript continues in sequence in Volume 5.)

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

I, LINDA BOLES, CRR, RPR, 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' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 2nd day of September, 2014.

Linda Boles

LINDA BOLES, CRR, RPR
FPSC Official Hearings Reporter
(850) 413-6734