BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination	)	
of Need for Citrus County Combined	)	DOCKET NO. 140110-EI
Cycle Power Plant	)	Submitted for filing: August 5, 2014
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DUKE ENERGY FLORIDA, INC.'S NOTICE OF FILING

Duke Energy Florida, Inc. ("DEF" or the "Company") hereby gives notice of filing the Rebuttal Testimony of Benjamin M.H. Borsch in support of DEF's Petition for Determination of Need for Citrus County Combined Cycle Power Plant filed May 27, 2014 (Document No. 02523-14).

Respectfully submitted this 5th day of August, 2014.

/s/ Blaise N. Gamba

John T. Burnett
Deputy General Counsel
Dianne M. Triplett
Associate General Counsel
DUKE ENERGY FLORIDA, INC.
Post Office Box 14042
St. Petersburg, FL 33733-4042
Telephone: (727) 820-5587
Facsimile: (727) 820-5519

James Michael Walls
Florida Bar No. 0706242
Blaise N. Gamba
Florida Bar No. 0027942
CARLTON FIELDS JORDEN BURT, P.A.
Post Office Box 3239
Tampa, FL 33601-3239
Telephone: (813) 223-7000
Facsimile: (813) 229-4133

CERTIFICATE OF SERVICE

I HEREBY CERTIFY a true and correct copy of the foregoing has been furnished to counsel and parties of record as indicated below via electronic mail and overnight mail this 5th day of August, 2014.

/s/ *Blaise N. Gamba*
Attorney

Michael Lawson
Florida Public Service Commission Staff
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850
Phone: (850) 413-6199
Facsimile: (850) 413-6184
Email: mlawson@psc.state.fl.us

Charles Rehwinkel
Deputy Public Counsel
Erik Sayler
Associate Public Counsel
Office of Public Counsel
c/o The Florida Legislature
111 West Madison Street, Room 812
Tallahassee, FL 32399-1400
Phone: (850) 488-9330
Email: rehwinkel.charles@leg.state.fl.us
Sayler.erik@leg.state.fl.us

Jon C. Moyle, Jr.
Karen A. Putnal
Moyle Law Firm
118 North Gadsden Street
Tallahassee, FL 32301
Phone: (850) 681-3828
Fax: (850) 681-8788
Email: jmoyle@moylelaw.com
kputnal@moylelaw.com

James W. Brew
F. Alvin Taylor
Brickfield Burchette Ritts & Stone, PC
1025 Thomas Jefferson St NW
8th FL West Tower
Washington, DC 20007-5201
Phone: (202) 342-0800
Fax: (202) 342-0807
Email: jbrew@bbrslaw.com
ataylor@bbrslaw.com

Robert Scheffel Wright
John T. LaVia, III
Gardner Law Firm
1300 Thomaswood Drive
Tallahassee, FL 32308
Phone: (850) 385-0070
Email: Schef@gbwlegal.com
Jlavia@gbwlegal.com

Marsha E. Rule
Rutledge Ecenia
119 South Monroe Street, Ste. 202
Tallahassee, FL 32301
Phone: (850) 681-6788
Fax: (850) 681-6515
Email: marsha@rutledge-ecenia.com

Gordon D. Polozola
NRG Energy, Inc.
112 Telly Street
New Roads, LA 70760
Phone: (225) 618-4084
Email: Gordon.Polozola@nrgenergy.com

Richard A. Zambo
Richard A. Zambo, P.A.
2336 S.E. Ocean Boulevard, #309
Stuart, FL 34966
Phone: (772) 225-5400
Email: richzambo@aol.com

Linda Loomis Shelley
Buchanan Ingersoll & Rooney /
Fowler White Boggs PA
101 North Monroe Street, Ste. 1090
Tallahassee, FL 32301
Phone: (850) 681-4260
Email: linda.shelley@bipc.com

Alan Seltzer
John Povilaitis
Buchanan Ingersoll & Rooney /
Fowler White Boggs PA
409 North Second Street, Ste. 500
Harrisburg, PA 17101-1357
Phone: (717) 237-4825/(717) 237-4825
Email: Alan.seltzer@bipc.com
John.povilaitis@bipc.com

Amy Fisher
Managing Director
GE Energy Financial Services, Inc.
800 Long Ridge Road
Stamford, CT 062927
Email: amy.fisher@ge.com

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination of Need for Citrus County Combined Cycle Power Plant

DOCKET NO. 140110-EI
Submitted for filing:
August 5, 2014

REBUTTAL TESTIMONY
OF BENJAMIN M.H. BORSCH

ON BEHALF OF
DUKE ENERGY FLORIDA, INC.

JOHN T. BURNETT
Deputy General Counsel
DIANNE M. TRIPLETT
Associate General Counsel
DUKE ENERGY FLORIDA, INC.
299 1st Avenue North
St. Petersburg, Florida 33733
Telephone: (727) 820-5184
Facsimile: (727) 820-5519

JAMES MICHAEL WALLS
Florida Bar No. 706272
BLAISE N. GAMBA
Florida Bar No. 027942
CARLTON FIELDS JORDEN
BURT, P.A.
4221 W. Boy Scout Blvd., Ste.1000
Tampa, Florida 33607
Telephone: (813) 223-7000
Facsimile: (813) 229-4133

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 in this Docket. 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 <u>prior to 2018</u> 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.

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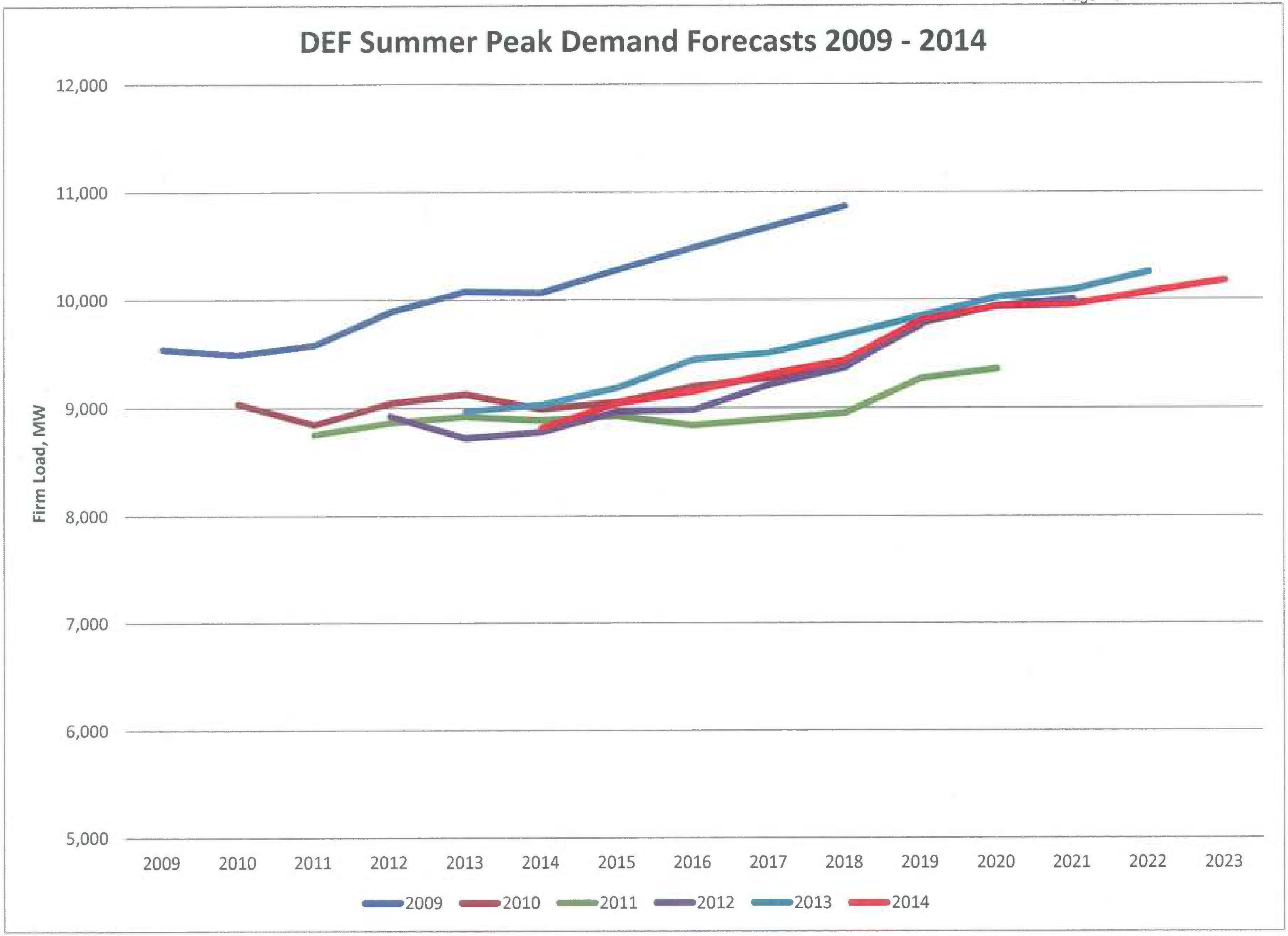

Fixed Costs changes associated with Citrus Delay and CRS Extension

		CPVRR ($M)	
Citrus Delay	Differential - Generation Capital	($61.75)	
Citrus Delay	Differential - Fixed O&M	($6.22)	
Citrus Delay	Differential - Gas Reservation Charges	$13.28	
		($54.69)	
CRS Extension	Differential - Capital RR	$0.46	
CRS Extension	Differential - O&M Capital Budget	$18.55	
CRS Extension	Differential - O&M Alternate Coal	$0.84	
	Differential - Ongoing Capex Annual Budget	$2.46	
		$21.85	
	Seasonal Purchases	$16.75	
	Fixed Costs associated with Citrus Delay and CRS Extension	($16.09)	Savings

Production Costs changes associated with Citrus Delay and CRS Extension

Btm ash cost	$1.34	
CaCO3 cost	$0.44	
CO2 cost	$0.00	
Fuel Cost	$98.91	
Gypsum cost	$0.46	
NH3 cost	$2.93	
NOx cost	$0.21	
SO2 cost	$0.02	
Start Cost	$5.23	
VOM COST	($2.99)	
Production Costs associated with Citrus Delay and CRS Extension	$106.57	Costs

Additional Costs associated with Citrus Delay and CRS Extension	$90.48

Citrus CC	CPVRR $M	Citrus 1640/1820																																										
Escalation Rate		May 2018/Nov 2018-April 2053/Oct 2053	Nominal	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054
		Summer Capacity not degraded	MW	-	-	-	-	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	-
		Winter Capacity not degraded	MW	-	-	-	-	-	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	-
	1,658.39	Generation Capital	$M/yr	-	-	-	-	90.90	205.33	199.04	193.00	187.19	181.59	176.20	170.99	165.88	160.78	155.68	150.59	145.49	140.40	135.30	130.20	125.11	120.01	114.92	109.82	105.26	101.77	98.82	95.86	92.91	89.96	87.00	84.05	81.10	78.14	75.19	72.24	69.28	66.33	63.38	34.94	-
	167.09	Fixed O&M	$M/yr	-	-	-	-	4.17	11.41	11.70	11.99	12.29	12.60	12.91	13.23	13.56	13.90	14.25	14.61	14.97	15.35	15.73	16.12	16.53	16.94	17.36	17.80	18.24	18.70	19.17	19.65	20.14	20.64	21.16	21.68	22.23	22.78	23.35	23.94	24.53	25.15	25.78	16.51	-
	1,739.63	Gas Reservation Charges	$M/yr	-	-	-	-	59.54	158.78	158.78	158.78	158.78	158.78	158.78	158.78	158.78	158.78	158.78	158.78	158.78	158.78	158.78	158.78	158.78	158.78	158.78	158.78	158.78	158.78	158.78	158.78	158.78	158.78	158.78	158.78	158.78	158.78	158.78	158.78	158.78	158.78	158.78	99.23	-
	3,565.11	Fixed Costs	$M/yr	-	-	-	-	154.61	375.51	369.51	363.76	358.25	352.97	347.88	342.99	338.21	333.46	328.71	323.97	319.24	314.52	309.81	305.10	300.41	295.73	291.06	286.39	282.28	279.25	276.76	274.29	271.82	269.37	266.94	264.51	262.10	259.70	257.32	254.95	252.59	250.25	247.93	150.69	-
	[illegible]	[illegible]		-																																								

Citrus CC	CPVRR $M	Citrus 1640/1820																																										
Escalation Rate		May 2019/Nov 2019-April 2054/Oct 2054	Nominal	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054
		Summer Capacity not degraded	MW	-	-	-	-	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640
		Winter Capacity not degraded	MW	-	-	-	-	-	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820
	1,596.65	Generation Capital	$M/yr	-	-	-	-	-	93	210	204	198	192	186	181	175	170	165	160	154	149	144	139	133	128	123	118	113	108	104	101	98	95	92	89	86	83	80	77	74	71	68	65	36
	160.87	Fixed O&M	$M/yr	-	-	-	-	-	4	12	12	12	13	13	13	14	14	14	15	15	15	16	16	17	17	17	18	18	19	19	20	20	21	21	22	22	23	23	24	25	25	26	26	17
	1,752.91	Gas Reservation Charges	$M/yr	-	-	-	-	60	159	159	159	159	159	159	159	159	159	159	159	159	159	159	159	159	159	159	159	159	159	159	159	159	159	159	159	159	159	159	159	159	159	159	159	99
	3,510.42	Fixed Costs	$M/yr	-	-	-	-	60	256	381	375	369	363	358	353	348	343	338	333	328	323	318	314	309	304	299	294	290	285	282	280	277	275	272	270	267	265	262	260	257	255	253	250	152
	[illegible]	[illegible]						60	256	374	367	361	355	350	344	339	334	329	324	319	314	309	304	298	293	288	283	278	274	270	267	265	262	259	256	253	250	248	245	242	239	236	234	141
	(61.75)	Differential - Generation Capital	$M/yr	-	-	-	-	(90.90)	(112.16)	11.42	11.02	10.63	10.27	9.94	9.62	9.38	9.24	9.12	8.99	8.86	8.73	8.61	8.48	8.35	8.22	8.10	7.97	7.31	6.12	5.50	5.42	5.35	5.28	5.20	5.13	5.05	4.98	4.91	4.83	4.76	4.69	4.61	30.02	35.81
	(6.22)	Differential - Fixed O&M	$M/yr	-	-	-	-	(4.17)	(7.13)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.91	16.93
	13.28	Differential - Gas Reservation Charges	$M/yr	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	59.54	99.23
	(54.69)																																											

$M	2014$	2013	2014	2015	2016	2017	2018	2019	2020	2021
Ongoing Capex -Alternate Coal - CRS Retires 2018		0.53	4.08	9.46	1.24					
Ongoing Capex - Alternate Coal - CRS Retires 2019		0.53	4.08	9.46	1.24					
Capital RR - CRS Retires 2018	**16**		-	-	7.50	9.46	2.45	-		
Capital RR - CRS Retires 2019	**17**		-	-	5.44	6.89	6.49	1.71		
Differential - Capital RR	0	-	-	-	(2)	(3)	4	2		
O&M - Annual Budget - CRS Retires 2018	**122**	24	28	45	27	21	11	3	-	
O&M - Annual Budget - CRS Retires 2019	**141**	24	28	45	27	21	21	11	6	
Differential - O&M Capital Budget	19	-	-	-	-	-	11	8	6	
O&M - Alternate Coal - CRS Retires 2018	**5**	-	1	1	2	1	1	0	-	
O&M - Alternate Coal - CRS Retires 2019	**6**	-	1	1	2	1	1	1	0	
Differential - O&M Alternate Coal	1	-	-	-	-	-	0	1	0	
Ongoing Capex - Annual Budget - CRS Retires 2018	**18**	3	2	7	6	3	2	0	-	
Ongoing Capex - Annual Budget - CRS Retires 2019	**21**	3	2	7	6	3	3	2	0	
Differential - Ongoing Capex Annual Budget	2	-	-	-	-	-	2	1	0	
Fixed Costs Revenue Requirement Impact due to CRS Extension	**22**									

Discount Rate 6.46%

3 Yr Avg Except CO2 and Fuel
CO2 & Fuel Escalated Based on 2 Previous Years

TP_1 Duke

Section	Variable	2014 PVRR, K$	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Station_RFP201413481	Btm ash cost	37,431	6,287	6,054	3,521	3,480	3,236	3,555	3,501	2,916	3,032	2,851	2,259	2,108
Station_RFP201413481	CaCO3 cost	55,131	7,381	8,041	4,788	4,824	4,573	5,111	5,138	4,361	4,621	4,416	3,559	3,377
Station_RFP201413481	CO2 cost	11,450,691	0	0	407,752	439,067	471,292	525,227	567,327	597,048	656,090	703,526	741,068	800,548
Station_RFP201413481	Fuel Cost	36,025,023	1,809,326	1,888,551	2,107,348	2,184,037	2,264,761	2,374,435	2,442,098	2,542,021	2,670,879	2,759,935	2,852,305	2,960,635
Station_RFP201413481	Gypsum cost	25,844	7,304	8,568	3,838	3,189	2,666	3,162	2,510	1,532	1,461	645	678	950
Station_RFP201413481	NH3 cost	126,059	14,411	12,562	12,472	11,848	11,234	11,941	11,334	10,656	11,319	10,439	8,379	7,977
Station_RFP201413481	NOx cost	3,023	397	311	258	246	237	255	247	225	229	207	192	198
Station_RFP201413481	SO2 cost	95	21	16	10	9	8	9	9	7	8	7	6	4
Station_RFP201413481	Start Cost	359,542	23,448	22,135	25,483	23,888	25,400	26,784	23,558	23,284	23,709	24,237	26,809	30,310
Station_RFP201413481	VOM COST	1,345,413	80,583	84,508	107,670	103,362	102,030	107,044	108,767	108,744	114,677	112,291	105,816	104,247
PVRR	$49,428,252	$49,428,252	1,949,158	[illegible]	2,673,139	2,773,951	2,885,437	3,057,523	3,164,489	3,290,795	3,486,024	3,618,554	3,741,072	3,910,354

Section	Variable	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Station_RFP201413481	Btm ash cost	2,170	2,370	2,437	2,428	2,483	2,489	2,268	2,113	2,276	2,467	2,360	2,525
Station_RFP201413481	CaCO3 cost	3,538	3,921	4,095	4,142	4,303	4,373	4,041	3,820	4,173	4,444	4,179	4,395
Station_RFP201413481	CO2 cost	875,422	967,231	1,061,628	1,153,451	1,227,494	1,314,081	1,385,203	1,463,804	1,572,021	1,690,893	1,803,035	1,938,266
Station_RFP201413481	Fuel Cost	3,086,021	3,231,243	3,395,338	3,537,816	3,676,573	3,828,521	3,952,890	4,075,236	4,213,955	4,356,271	4,517,189	4,669,759
Station_RFP201413481	Gypsum cost	1,368	548	377	370	372	367	328	301	319	339	319	336
Station_RFP201413481	NH3 cost	8,220	8,818	9,165	9,673	10,072	10,388	9,497	8,824	9,210	9,636	9,964	10,376
Station_RFP201413481	NOx cost	205	220	230	230	246	256	241	237	248	259	265	280
Station_RFP201413481	SO2 cost	4	5	5	5	5	5	5	4	5	5	5	5
Station_RFP201413481	Start Cost	29,506	30,634	31,616	32,933	33,075	33,724	37,475	40,275	40,480	42,728	45,577	45,195
Station_RFP201413481	VOM COST	107,876	113,020	118,773	120,740	126,753	131,217	129,223	127,156	130,468	133,849	140,095	144,898
PVRR	$49,428,252	4,114,331	4,358,008	4,623,664	4,861,788	5,081,376	5,325,420	5,521,170	5,721,770	5,973,155	6,240,892	6,522,987	6,816,034

Section	Variable	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
Station_RFP201413481	Btm ash cost	2,693	2,608	2,684	2,730	2,701	2,773	2,811	2,749	2,775	2,886	2,836	2,833
Station_RFP201413481	CaCO3 cost	4,605	4,382	4,432	4,428	4,303	4,340	4,322	4,149	4,114	4,201	4,055	4,124
Station_RFP201413481	CO2 cost	2,082,940	2,220,739	2,365,505	2,511,368	2,661,322	2,830,827	3,016,418	3,190,195	3,389,816	3,610,266	3,834,969	4,073,657
Station_RFP201413481	Fuel Cost	4,821,663	4,985,783	5,109,461	5,224,852	5,341,184	5,458,852	5,597,590	5,709,976	5,833,748	5,952,920	6,090,452	6,231,162
Station_RFP201413481	Gypsum cost	352	335	338	338	329	331	330	317	314	321	310	315
Station_RFP201413481	NH3 cost	10,824	11,102	11,484	11,535	11,779	11,983	12,007	12,226	12,555	12,667	12,738	12,653
Station_RFP201413481	NOx cost	291	304	307	319	321	328	338	346	355	366	375	365
Station_RFP201413481	SO2 cost	6	6	6	6	6	6	6	6	6	7	7	6
Station_RFP201413481	Start Cost	46,677	48,675	49,815	49,935	50,524	52,660	51,855	53,722	53,854	57,606	58,218	56,559
Station_RFP201413481	VOM COST	149,129	156,439	159,583	163,503	167,406	171,808	175,973	181,307	185,692	189,657	194,143	189,831
PVRR	$49,428,252	7,119,178	7,430,371	7,703,615	7,969,013	8,239,874	8,533,909	8,861,652	9,154,992	9,483,230	9,830,897	10,198,103	10,571,505

TP_1 Duke, One Year Delay

Section	Variable	2014 PVRR, K$	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Station_RFP201413800	Btm ash cost	38,776	7,266	6,852	3,521	3,480	3,236	3,555	3,501	2,916	3,032	2,851	2,259	2,108
Station_RFP201413800	CaCO3 cost	55,575	7,525	8,496	4,788	4,824	4,573	5,111	5,138	4,361	4,621	4,416	3,559	3,377
Station_RFP201413800	CO2 cost	11,450,691	0	0	407,752	439,067	471,292	525,227	567,327	597,048	656,090	703,526	741,068	800,548
Station_RFP201413800	Fuel Cost	36,123,930	1,857,205	1,972,858	2,107,348	2,184,037	2,264,761	2,374,435	2,442,098	2,542,021	2,670,879	2,759,935	2,852,305	2,960,635
Station_RFP201413800	Gypsum cost	26,309	7,446	9,052	3,838	3,189	2,666	3,162	2,510	1,532	1,461	645	678	950
Station_RFP201413800	NH3 cost	128,994	15,858	15,034	12,472	11,848	11,234	11,941	11,334	10,656	11,319	10,439	8,379	7,977
Station_RFP201413800	NOx cost	3,237	554	437	258	246	237	255	247	225	229	207	192	198
Station_RFP201413800	SO2 cost	112	35	25	10	9	8	9	9	7	8	7	6	4
Station_RFP201413800	Start Cost	364,771	25,994	26,576	25,483	23,888	25,400	26,784	23,558	23,284	23,709	24,237	26,809	30,310
Station_RFP201413800	VOM COST	1,342,424	77,268	83,949	107,670	103,362	102,030	107,044	108,767	108,744	114,677	112,291	105,816	104,247
PVRR	$49,534,818	$49,534,818	1,999,151	2,123,279	2,673,139	2,773,951	2,885,437	3,057,523	3,164,489	3,290,795	3,486,024	3,618,554	3,741,072	3,910,354

Section	Variable	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Station_RFP201413800	Btm ash cost	2,170	2,370	2,437	2,428	2,483	2,489	2,268	2,113	2,276	2,467	2,360	2,525
Station_RFP201413800	CaCO3 cost	3,538	3,921	4,095	4,142	4,303	4,373	4,041	3,820	4,173	4,444	4,179	4,395
Station_RFP201413800	CO2 cost	875,422	967,231	1,061,628	1,153,451	1,227,494	1,314,081	1,385,203	1,463,804	1,572,021	1,690,893	1,803,035	1,938,266
Station_RFP201413800	Fuel Cost	3,086,021	3,231,243	3,395,338	3,537,816	3,676,573	3,828,521	3,952,890	4,075,236	4,213,955	4,356,271	4,517,189	4,669,759
Station_RFP201413800	Gypsum cost	1,368	548	377	370	372	367	328	301	319	339	319	336
Station_RFP201413800	NH3 cost	8,220	8,818	9,165	9,673	10,072	10,388	9,497	8,824	9,210	9,636	9,964	10,376
Station_RFP201413800	NOx cost	205	220	230	230	246	256	241	237	248	259	265	280
Station_RFP201413800	SO2 cost	4	5	5	5	5	5	5	4	5	5	5	5
Station_RFP201413800	Start Cost	29,506	30,634	31,616	32,933	33,075	33,724	37,475	40,275	40,480	42,728	45,577	45,195
Station_RFP201413800	VOM COST	107,876	113,020	118,773	120,740	126,753	131,217	129,223	127,156	130,468	133,849	140,095	144,898
PVRR	$49,534,818	4,114,331	4,358,008	4,623,664	4,861,788	5,081,376	5,325,420	5,521,170	5,721,770	5,973,155	6,240,892	6,522,987	6,816,034

Section	Variable	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
Station_RFP201413800	Btm ash cost	2,693	2,608	2,684	2,730	2,701	2,773	2,811	2,749	2,775	2,886	2,836	2,833
Station_RFP201413800	CaCO3 cost	4,605	4,382	4,432	4,428	4,303	4,340	4,322	4,149	4,114	4,201	4,055	4,124
Station_RFP201413800	CO2 cost	2,082,940	2,220,739	2,365,505	2,511,368	2,661,322	2,830,827	3,016,418	3,190,195	3,389,816	3,610,266	3,834,969	4,073,657
Station_RFP201413800	Fuel Cost	4,821,663	4,985,783	5,109,461	5,224,852	5,341,184	5,458,852	5,597,590	5,709,976	5,833,748	5,952,920	6,090,452	6,231,162
Station_RFP201413800	Gypsum cost	352	335	338	338	329	331	330	317	314	321	310	315
Station_RFP201413800	NH3 cost	10,824	11,102	11,484	11,535	11,779	11,983	12,007	12,226	12,555	12,667	12,738	12,653
Station_RFP201413800	NOx cost	291	304	307	319	321	328	338	346	355	366	375	365
Station_RFP201413800	SO2 cost	6	6	6	6	6	6	6	6	6	7	7	6
Station_RFP201413800	Start Cost	46,677	48,675	49,815	49,935	50,524	52,660	51,855	53,722	53,854	57,606	58,218	56,559
Station_RFP201413800	VOM COST	149,129	156,439	159,583	163,503	167,406	171,808	175,973	181,307	185,692	189,657	194,143	189,831
PVRR	$49,534,818	7,119,178	7,430,371	7,703,615	7,969,013	8,239,874	8,533,909	8,861,652	9,154,992	9,483,230	9,830,897	10,198,103	10,571,505

	2014 PVRR, K$
Delta Citrus 1 Yr Delay Minus Citrus Base	$106,566

			2014	2015	2016	2017	2018	2019
MW	Citrus 2018							
50	50 MW - Jun-Aug		-	-	-	-	1,088	-
		846						
MW	Citrus 1 YR Delay							
500	500MW - May - Sep		-	-	-	-	-	18,276
150	150MW - May - Sep		-	-	-	-	5,438	-
			-	-	-	-	5,438	18,276
		17,594						
		16,748						

	Cost	Ratio
Debt	3.75%	50.00%
Equity	10.50%	50.00%
Composite Tax Rate	35.26%	
Discount Rate	6.46%	
Insurance Rate	0.05%	
Property Tax Rate	0.91%	
AFUDC Rate	6.464%	
AFUDC Debt (After Tax)	3.75%	
Capitalized Interest Rate	3.750%	
Construction Escalation Rate	0.0%	