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: September 10, 2014

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DUKE ENERGY FLORIDA, INC.'S SEVENTH REQUEST FOR CONFIDENTIAL CLASSIFICATION REGARDING PORTIONS OF DEPOSITION OF BENJAMIN M.H. BORSCH

Duke Energy Florida, Inc. ("DEF" or the "Company"), pursuant to Section 366.093, Florida Statutes, and Rule 25-22.006(3), Florida Administrative Code ("F.A.C."), files this Request for Confidential Classification Regarding Portions of the August 11, 2014 Deposition Transcript of Benjamin M.H. Borsch. An unredacted version of the information and documents discussed above are being filed under seal with the Commission as Appendix A on a confidential basis to keep the competitive business information in those documents confidential.

With respect to the confidential information contained in the deposition transcript, DEF filed its Notice of Intent to Request Confidential Classification on August 20, 2014 (Document No. 04632-14). Pursuant to Rule 25-22.006(3), Florida Administrative Code, this request is timely. DEF hereby submits the following in support of its confidentiality request.

BASIS FOR CONFIDENTIAL CLASSIFICATION

Section 366.093(1), Florida Statutes, provides that "any records received by the Commission which are shown and found by the Commission to be proprietary confidential business information shall be kept confidential and shall be exempt from [the Public Records Act]." § 366.093(1), Fla. Stat. Proprietary confidential business information means information that is (i) intended to be and is treated as private confidential information by the Company, (ii) because disclosure of the information would cause harm, (iii) either to the Company's ratepayers or the Company's business operation, and (iv) the information has not been voluntarily disclosed to the public. § 366.093(3), Fla. Stat. Specifically, "information concerning bids or other contractual data, the disclosure of which would impair the efforts of the public utility or its affiliates to contract for goods or services on favorable terms" is defined as proprietary confidential business information. § 366.093(3)(d), Fla. Stat. Additionally, subsection 366.093(3)(e) defines "information relating to competitive interests, the disclosure of which would impair the competitive business of the provider of the information," as proprietary confidential business information.

DEF is requesting confidential classification of portions of Mr. Borsch's deposition transcript because it contains confidential competitive business and strategic planning information as well as confidential contractual information, and competitively sensitive confidential information of other parties the release of which would harm competitive business interests and potentially violate contractual non-disclosure agreements. Affidavit of Borsch, ¶¶3-4. The disclosure of this information would adversely impact DEF's and other parties competitive business interests. Affidavit of Borsch, ¶ 5.

The Company must be able to assure bidders and suppliers that sensitive business information will be kept confidential. If such assurances are not provided, potential bidders know that the terms of their bids are subject to public disclosure, they might withhold sensitive information necessary for the utility to fully understand and accurately assess the costs and benefits of their proposals. Persons or companies who otherwise would have submitted bids in response to the utility's RFPs might not do so if there is no assurance that their proposals would be protected from disclosure. Affidavit of Borsch, ¶ 5. Indeed, most of the contracts at issue contain confidentiality provisions that prohibit the disclosure of the terms of the contract to third parties. Id. If third parties were made aware of confidential contractual terms and conditions that the Company has with other parties, they may offer DEF less competitive contractual terms and conditions in any future contractual negotiations. Without DEF's measures to maintain the confidentiality of sensitive terms in contracts between DEF and these contractors, the Company's efforts to obtain competitive contracts would be undermined. Affidavit of Borsch, ¶ 6.

Confidentiality Procedures

Strict procedures are established and followed to maintain the confidentiality of the terms of all of the confidential and competitively sensitive documents and information at issue, including restricting access to those persons who need the information and documents to assist the Company. See Affidavit of Borsch, ¶ 7.

At no time has the Company publicly disclosed the confidential information or documents at issue; DEF has treated and continues to treat the information and documents at issue as confidential. See Affidavit of Borsch, ¶ 8. DEF requests this information be granted confidential treatment by the Commission.

Conclusion

The competitive, confidential information at issue in this Request fits the statutory definition of proprietary confidential business information under Section 366.093, Florida Statutes, and Rule 25-22.006, F.A.C., and therefore that information should be afforded confidential classification. In support of this motion, DEF has enclosed the following:

(1) A separate, sealed envelope containing one copy of the confidential Appendix A to DEF's Seventh Request for Confidential Classification which DEF intends to request confidential classification with the appropriate section, pages, or lines containing the confidential information highlighted. **This information should be accorded confidential treatment**

pending a decision on DEF's Request by the Commission;

(2) Two copies of the documents with the information for which DEF intends to request confidential classification redacted by section, pages, or lines where appropriate as Appendix B; and,

(3) A justification matrix of the confidential information contained in Appendix A supporting DEF's Request, as Appendix C.

WHEREFORE, DEF respectfully requests that the redacted portions of the deposition transcript of Benjamin M.H. Borsch be classified as confidential for the reasons set forth above.

Respectfully submitted this 10th day of September, 2014.

/s/ Blaise N. Gamba

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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 10th day of September, 2014.

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination of Need for Citrus County Combined Cycle Power Plant	))))	DOCKET NO. 140110-EI
In re: Petition for Determination of Cost Effective Generation Alternative to Meet Need Prior to 2018 for Duke Energy Florida, Inc.	)))))	DOCKET NO. 140111-EI

Seventh Request for Confidential Classification

Exhibit B

REDACTED

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination of Need for Citrus County Combined Cycle Power Plant, by Duke Energy Florida, Inc.,	**DOCKET NO.** 140110-EI
In re: Petition for Determination of Cost Effective Generation Alternative to Meet Need Prior to 2018, by Duke Energy Florida, Inc., /	**DOCKET NO. 140111-EI**

DEPOSITION OF:	BENJAMIN M.H. BORSCH
TAKEN ON BEHALF OF:	The Intervenors
DATE:	August 11, 2014
TIME:	Commenced at 1:35 p.m. Concluded at 7:47 p.m.
LOCATION:	106 East College Avenue Tallahassee, Florida
REPORTED BY:	MARY ALLEN NEEL, RPR, FPR Notary Public, State of Florida at Large

ACCURATE STENOTYPE REPORTERS, INC.
2894-A REMINGTON GREEN LANE
TALLAHASSEE, FLORIDA 32308
850.878.2221

essentially the same as Hines 1, 2, and 3?

A. Yes. I mean, there are some differences, in that Osprey also has duct firing, and there are some design differences, but the overall configuration is similar.

Q. When the duct firing is not running, would the heat rate of Osprey be comparable to the heat rate of, say, Hines 1 and 2?

A. I would think that it would, although in its proposals to us, Calpine has consistently quoted a slightly higher heat rate.

Q. And the quoted heat rates were in the range of [redacted]

A. I believe that's correct.

Q. Continuing to focus on Calpine's July 3rd offer, since that is the most recent offer that we have made to Duke, the proposed purchase price for Osprey to Duke is [redacted] in nominal 2020 dollars; correct?

A. That's my understanding.

Q. And if you know, what's the present value of that in 2014 dollars?

A. I could look it up. Off the top of my head, I'm going to say that it was about [redacted]

Q. We have also talked about the possibility of Duke purchasing the plant before 2020; correct?

A. Yes.
Q. And generally speaking, we talked about buying it sometime during 2016?
A. Yes.
Q. Would you know what the present value of the purchase price of the [redacted] in 2020 taken back to, say, January 2, 2016, and December 31, 2016, would be?
A. No. I had a number that I had calculated for January 1st or 2nd of 2016. I don't believe I have it in my head. It was closer to something like [redacted]. We didn't calculate the end-of-year value.
Q. The discount rate you used is 6.46 percent?
A. It is. Somewhere somebody is checking my math, but . . .
Q. I would think that [redacted] in 2020 discounted by 6.46 percent to January 1, 2016, would be significantly less than [redacted] Would you agree with that?
A. That seems plausible, and I could probably find something to refer to that would check that value.
Q. Would you do that, please?
A. Let's see if I've got it in my testimony. If not, I'll see where else we can find it. I don't know that it's in here, but hold on.

Okay. The value that I have, Schef -- oh, well, that's the problem. I'm going to apologize to you and tell you that I have been -- the numbers that I have in my head have been CPVRR values and not discounted cash values.

Q. Okay.

A. So to go back to your other question, as it turns out, the [redacted] that I had in mind was the CPVRR value for the [redacted] 2020. I don't off the top of my head, and it does not appear to be in my testimony at this time, have the cash value numbers. I know that I have calculated them, but I don't believe I have them with me.

Q. I think that in our conversations, I've heard a number in the vicinity of the [redacted] that you mentioned a moment ago. Does that sound about right to you?

A. It does.

MR. REHWINKEL: Schef, would you repeat that number? Someone shuffled papers, and I didn't hear the answer.

MR. WRIGHT: Yes. The number itself was [redacted] My question was, I believe that I've heard a figure for a discounted cash value on the order of [redacted] which is a number that Ben mentioned a moment ago, and he agrees that that's about right. Right?

THE WITNESS: Yes.

MR. REHWINKEL: Thank you. It was just the number that got obliterated.

THE WITNESS: So the second value that you asked me about, which was the 2016 value, I don't have that number, although I will say this: It's essentially the same number, because at least in the way that we were considering the transaction, we were considering that the -- we would always start with a value that was [redacted] in 2020 and then -- you know, so it was only a question of discounting the cash to different years. And while I can't tell you what the nominal dollar values were in each one of those years, we were discounting them so that they would always be the same real dollar number as the [redacted] nominal in 2020.

BY MR. WRIGHT:

Q. If you can explain it conveniently, why is the CPVRR value greater than -- as of a given date, greater than the discounted cash value as of the same date?

A. Well, the CPVRR value is the present value, the cumulative present value of the revenue requirements to cover that cash expenditure. So the revenue about a couple of your rebuttal exhibits, particularly BMHB-18.

A. Okay.

Q. Kind of starting at the bottom and then coming back to work through the components, do I understand page 1 of your Exhibit BMHB-18 as indicating that Duke's evaluation of the CPVRR of the July 3rd offer is a negative CPVRR impact of [redacted]

A. Yes.

Q. And does that -- that assumes a purchase price of [redacted] in 2020?

A. Correct.

Q. Would it be true that an earlier purchase would reduce the -- with the purchase price present-valued back to some smaller number, would reduce the negative CPVRR value?

A. Well, actually, what we found was that the CPVRR of the purchase price was relatively constant. I mean, it varied by a million dollars or something like that, depending on when the purchase was executed. So in terms of evaluating the difference in value between an earlier purchase and a later purchase, given that we were using a static set of, you know, real dollar price, the date of the execution -- well, the date of the execution was significant, but it wasn't significant then, of course, related to the cost of the PPA is also the amount of time that we were paying the wheel.

Q. Okay. And looking at BMHB-18, the wheel is [redacted]

A. Uh-huh.

Q. A negative CPVRR impact of [redacted]

A. Correct.

Q. And what is the amount of wheeling charges assumed there in megawatts or kilowatts? Is it 515, 515 megawatts?

A. It's 515 -- no, I'm sorry. Let me take that back. We assumed that Osprey would be available -- because of transmission constraints on the TECO system, we assumed that we would be able to access 249 megawatts that Osprey has firm rights to in the peak months -- and for the purposes of modeling, we used July, July, August, and January -- and that we would have access to the full 515 megawatts in the remainder of the months. So the wheeling charges were calculated monthly based on those megawatts using TECO's current tariff rate.

Q. Just so I'm clear, then, your modeling assumptions were that you paid for 249 megawatts of wheeling in January, June, July, and August; correct?

A. Yes.

Q. And for 515 megawatts of wheeling service in the other eight months of the year?

A. Yes.

Q. I would like to explore the [redacted] value that's shown for the net present value of capacity charges for the PPA.

A. Uh-huh.

Q. That's a pretty big negative number, [redacted] negative.

A. Yes.

Q. Is that just the net present value of the capacity charges under the PPA?

A. I believe that it is.

Q. What, if any, value of avoiding the Suwannee capacity costs is incorporated into this analysis?

A. I'm not sure I understand the question.

Q. If you acquire -- well, would you agree that if you acquire Osprey either through a PPA or a purchase, you would not build the Suwannee peakers?

A. That is the way we modeled it, yes. It was an either/or.

Q. Right. So your analysis shows that there's a negative [redacted] impact on the cost-effectiveness of Osprey due to the PPA capacity costs?

A. Well, the first answer to that question is yes, but -- well, I guess I would just stop with yes for now and let you go on. We'll get to the details in an minute, I'm sure.

Q. Good. So my question is, where, if at all, in the analysis reflected here does the value of not building Suwannee show up?

A. I see. Well, this is a differential analysis, so the values -- let me suggest for a moment that we turn to page 3 of that same exhibit, which is a somewhat less detailed breakdown, but encompasses the same totals, and if you look in the first column under "2020 Osprey Acquisition," where you can see the negative [redacted] at the bottom.

So understand that this is a differential CPVRR analysis. So we took all the costs associated with operating the system in the case where we built the Suwannee peakers, and we took all the costs that we attributed to the system in the case where we had the [redacted] in keeping with the July 3rd offer from the Osprey case, and essentially, we took the differential between those two. And on page 3 of the exhibit, what you can see are those differentials stacked up in the categories that are shown there.

On page 1 of the exhibit, in essence, what we were trying to demonstrate, for purposes of our conversations with Calpine, was what kinds of puts and takes were involved in adjusting from our previous analysis that we had discussed that's in my direct testimony to get to the [redacted] number, so that for the purposes of our conversations, there was sort of an understanding of, oh, yeah, this cost got added, this cost got reduced, and so forth, compared to the original analysis.

So from my perspective, the kind of official view of this is the one which is show on page 3. The analysis which is on page 1, which, knock on wood, is consistent, is to display for the purposes of explanation what the puts and takes were from our previous version.

So to get back to your question, the answer is that the capacity costs attributable to the peakers, which is to say the capital costs of the peakers themselves and the associated revenue requirements, if you turn to page 3, that differential is actually reflected -- it's a very small differential, but that differential is essentially reflected in the negative [redacted] you see at the top, which is that differential between the capital costs in each case. And then you can see the tradeoffs in different other areas.

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Q. Okay. Let's look at that line. In the Osprey [redacted]

A. Yep.

Q. Is the [redacted] good for Osprey?

A. Yes. So that [redacted] represents the fact that in the [redacted] case, because you're deferring build due to the presence of the PPA, there is a capital cost savings in that portfolio.

Q. And similarly, the [redacted] shown in the next cell below the [redacted], that's a fuel cost savings attributable to Osprey?

A. Yes. You need to recognize, however, that part of the reason that fuel cost savings is such a large number is because the fuel for actually running Osprey is included in the PPA row, so there's a trade-off between those two.

Q. So skipping down to the PPA row, we've got a [redacted] but that includes the fuel costs?

A. Yes. That includes both the fixed transportation costs, the actual fuel commodity costs, and the PPA capacity charges. And in fairness, you have to recognize that because the model is holistic, not all of that cost differential is directly related to Osprey, because there is sort of a -- you know, there's change in dispatch effects, so it also may encompass moneys that are changing back and forth between our other PPAs.

Q. For example, the [redacted] value in the cogens row, would that be some reduced purchases from the cogens attributable to Osprey being available?

A. Yes.

Q. What is the makeup of the [redacted] negative impact in the fixed costs column under the [redacted]

A. Ah, now you're going to catch me in having made an error and misspeaking a moment ago. Sorry.

The fixed gas transportation costs are in the fixed costs row. I said they were in the PPA row. I was wrong. Only the variable costs are in the PPA row. The fixed gas transportation costs are in the fixed row. So the lion's share of that differential is the fixed transportation for Osprey, although it also will encompass differentials in fixed O&M between various units and other things like that.

Q. There's a set of numbers under the heading "Additional Costs" just below the middle of the page.

A. Yes.

Q. The plant condition program alignments, what does that refer to?

A. Well, when we were considering the acquisition of the Osprey plant, we went to our engineering staff and asked them, you know, based on their experience with independent power plants, what kinds of costs they thought we might incur to bring Osprey in alignment with our maintenance practice. So the principal cost here is a perceived difference in money that we would be charged by the OEMs to bring Osprey into alignment with an OEM LTSA program, which is consistent with our maintenance practices across the rest of the fleet.

Q. And what was the FOM adjustment line?

A. The FOM adjustment line is an adjustment which we put in, recognizing that Osprey's staffing and salary structure is probably slightly lower than it would be if we were operating the plant. So, you know, without going through the exercise of having tried to calculate on an annual basis, you know, what that differential would be and assigning it out as a string of numbers over 20 years of operation, we made an adjustment of the [redacted]

Q. And what was that an adjustment to?

A. Well, that's a good point. Going back to my point about the pluses and minuses or the puts and takes, if you will, in the analysis that we did that forms the basis of my direct testimony in -- I believe it's Exhibit 8 to my direct testimony. We did not take into account in that analysis a number of these factors which we -- you know, basically, at that point, we were still doing what was a preliminary analysis.

So we had kind of done that preliminary analysis on what I will call straight-up numbers, in the sense that we had not gone through and tried to refine a number of these details. So, for instance, in that analysis, we used Calpine's projected fixed O&M and staffing numbers verbatim. And then we came back later and said, okay, if we were really going to own this plant, we would probably staff a little more, or our union requirements would cause us to pay the staff a little more, and we would have a slightly higher basis for that fixed O&M.

Q. And do I understand what you said a minute ago to indicate that rather than model that over 20 or 30 years of buying and owning the capacity, you just put a one-time capital adjustment in there of [redacted]

A. Yes. For the purposes of this analysis, yes.

Q. And what are the transaction costs shown in that block of cost values?

A. Well, again, we know that if we were to actually consummate an acquisition, we would hire an outside engineer to do due diligence. There would be legal fees and other things that would be encompassed in having to do the transaction.

Q. Moving to the next block of numbers below that, there is a negative [redacted] shown opposite the original purchase price of $300 million. Is that the adverse CPVRR impact of buying the plant for $300 million?

A. Yes. So --

Q. And the -- go ahead.

A. I was just going to say, what we did there was essentially -- you can see the negative [redacted] The [redacted] we talked about a few minutes ago. So we netted those out and showed that overall, that improved the deal, so to speak, by the [redacted] difference.

Q. Down at the bottom, we've got [redacted] of adjustments, [redacted] for Suwannee project sunk costs. Is that part of the [redacted]

A. No, it's not.

Q. What does that reflect?

A. Well, in our conversations with Calpine, we have made it known that, you know, because of the schedule that we're on to meet the June 2016 in-service date for the Suwannee project, that we have begun expending funds for that project. And the current value as of the time this was done for the sunk expenditures on that, which are predominantly the turbine payments, is approximately [redacted]

So one of the things that has been discussed back and forth in the various offers that Calpine has made is that Calpine and DEF would negotiate a settlement of those costs. But those are outside the CPVRR per se.

Q. Okay. Am I correct that Duke does not have advance Commission approval for those expenditures for the turbine payments?

A. I believe you are.

Q. If you know, why didn't Duke seek Commission approval earlier of those expenditures?

A. I think the short answer is that I don't know per se. That's a strategy question that would have to go to other people.

Q. Did it have anything to do, if you know, with when Duke realized that there was a market power concern with the possible acquisition of Osprey or other projects?

A. I don't believe so. I believe that it had more to do with the completion of analysis and the scheduling of our ability to seek Commission approval.

Q. When did you first -- isn't it true that you first identified a need in 2016 or thereabouts as early as 2012?

A. We did, although at the time, that need was different, and we recognized even then that a considerable amount of analysis would have to go on before we nailed down the right mix of resources to fill the need.

Q. In the July 3rd offer, Calpine offered a [redacted] correct?

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

Q. That's shown over here in 17?

A. Uh-huh. I was looking for it. There it is, yes.

Q. Does that value relate to any of the numbers in page 1 of BMHB-18?

A. No.

Q. That relates to a scenario in which Duke would [redacted]

A. Yes, that's correct. And that's reflected, actually, on page 2 of Exhibit 18.

Q. What does the [redacted] and the negative [redacted] in the bottom left cell there show? I can read the words, but I don't quite understand what it means.

A. Fair enough. The negative [redacted] again is the CPVRR relative to the self-build case, and that [redacted]

Q. Back to page 1 of BMHB-18. If we shorten up the -- if we shorten the term of the PPA, does the [redacted]

A. Yes.

Q. And are the wheeling charges impacted?

A. Yes. They would be reduced to the degree that the -- you know, if the acquisition happened sooner, the transmission would be constructed sooner, and we would spend less time wheeling the power.

Q. And the present value of the transmission investment is likewise rolled into this, and that's in the transmission costs and timing adjustments?

A. Right, and again, recognizing that the purpose of this page is to give a reference back to the costs that were calculated in the direct testimony. So in the direct testimony, we assumed that the transmission would cost [redacted] nominal for a 2018 transmission in-service date. In the updated analysis following Calpine's bid, we assumed that the transmission would be -- would cost $150 million nominal for a 2023 in-service date.

Q. And the 2023 in-service date teed off the 2020 acquisition?

A. Correct.

Q. So that was -- just so I'm clear, that was $150 million in 2023?

A. Well, again --

Q. Nominal dollars?

A. Nominal dollars, again recognizing that we used an expenditure pattern that spanned a three-plus-year construction period. But to the point of your question, yes.

Q. In the analysis, then there was some spending in 2020, 2021, 2022, and 2023, the total nominal dollars of which is 150?

A. Yes.

Q. If the transmission were to be built earlier, that $150 million would be less; correct?

A. Well, I guess the --

Q. In nominal dollars?

A. Well, let me explain that for a second. The actual estimate that we have is $150 million, which is actually based on a 2018 in-service date. So it's actually escalated slightly to the 2023. I believe it ends up being 154 million nominal dollars for the 2023 in-service date, and then either way, it's brought back.

So to that point, since we're using an estimate of $150 million with a 2018 nominal and then escalating and discounting, there's not really a material change in the cost sliding it back and forth [redacted] I mean, there's a change but it's $5 million or something like that.

Q. Well, do you assume that transmission construction costs and materials costs are going to be increasing over the next 10 years, let's say?

that's what it's really going to cost."

Q. Do you know what moving the acquisition up from 2020 to, say, very early January of 2016 would do to the negative [redacted] of PPA charges?

A. Off the top of my head, I do not. But I will say in general that the [redacted] essentially represents [redacted] Because of the combination of CPVRR adjustment and the escalation factors involved, it's not exactly linear, but I think it's probably -- you know, you can sort of get a reasonable approximation by saying two versus five.

Q. Two versus five or one versus five?

A. Or one versus five. Well, I guess that depends on where you're setting the acquisition date, yes. So if you were setting the acquisition date on the first of 2016, [redacted]

A. Roughly speaking.

Q. Now, being a differential analysis, does this address the cost of firm transmission for natural gas service?

MR. WALLS: Object to the form.

MR. WRIGHT: If you understood, you can answer, but if not, I'll try again.

REDACTED

for the PPA which results in the [redacted] negative value in BMHB-18, do those values include what you refer to in your direct testimony as imputed debt or imputed equity costs to compensate for imputed additional debt?

A. No.

Q. I'm going to apologize in advance, because I may well have asked this question before, but looking at numbers reminds me that I want to ask questions, not surprisingly.

Looking at page 2 of Exhibit 18, the [redacted] that does not reflect anywhere on page 1 of BMHB-18, does it?

A. No. Those are separate analyses.

Q. I have a couple more questions about the FERC market power issue. And you may have answered the first one, but when did you identify the FERC market power concern, "you" being Duke?

A. Right. We identified that concern, I would say, in about -- somewhere between January and February of this year, late January or early February. I mean, it wasn't that we didn't know it was there. We just -- you know, we hadn't gotten up to looking closely at it.

Q. And to your recollection, how did it come about that you looked more closely at it in late January or early February of this year?

negative, and the point estimate was negative?

A. That's correct.

Q. BMHB-10, is Osprey in there?

A. Only as far as the PPA. The acquisition is not.

Q. All right. So PPA 1 is the Osprey PPA?

A. Yes.

Q. What then is the Acquisition - PPA Mix 1?

A. We were offered a smaller acquisition, 143 megawatts summer-only acquisition by another party. So in evaluating it, because it was only 143 megawatts, we combined it with the PPAs. In this case, the Acquisition - PPA Mix 1 represents a PPA with Osceola and that acquisition combined.

Q. Looking back at Exhibit 18, the [redacted] shown at the very top of that, that's the point estimate shown back in BMHB-9?

A. Yes, which is also reflected on BMHB-8.

Q. If you recall, what were the sensitivity conditions that flipped Osprey into the positive range as shown in BMHB-9?

A. Well, I was looking to see, because I was pretty sure that those numbers were in here as an exhibit. Let me see if I can find it. That's the only Osceola portion of the exhibit.

A. Yes.

Q. So the [redacted] reference number is the CPVRR effect of purchasing Osprey at $300 million, which was the offer on the table in April?

A. Yes, although I'm, to be honest with you, a little confused about how we had gotten to the [redacted] since we went back and recalculated that number and came up with [redacted] although I think most of that difference may be the difference between a 2013 dollar value and a 2014 dollar value.

Q. I'm not seeing a year basis here, but this table, Exhibit 13, is that 2013?

A. Yes, these are 2013 dollars.

Q. And then your assumption in the low transmission at that point was [redacted] in PVRRs?

A. Correct. And I guess I should say that at this stage in the game, we were not actually redoing the calculations in the sense -- you know, we were trying to produce a sensitivity range, so we were using approximations of the numbers and not doing specific calculations where you would tie that number directly to a transmission cost. We were just suggesting that there was a range available based on conversations that at the time my team was having with subject matter experts in these various areas.

Q. Do you know what purchase price was assumed in the "low diff" case there?

A. Not specifically, no.

Q. Can you cipher it out for us based on the [redacted] number that's there?

A. I actually think it's backwards, in the sense that I think that we said, you know, suppose they could whack $150 million or something out of the -- and, you know, we just postulated a round number in CPVRR rather than actually calculating a specific purchase price.

Q. Down toward the bottom of that middle block of numbers on the left, there's a row that says "Case Sensitivities for CPVRR Results." In the "low diff" case, there's a number that looks like positive [redacted]

A. Yes.

Q. Does that correspond to the value that's above the breakeven line in BMHB-9?

A. Yes.

[redacted]

Q. Thank you. Do you know what the assumed purchase price that corresponded to the [redacted] value was?

A. As I said, we just took the [redacted] as a round number to work with. We didn't assume a particular purchase price.

Q. And did this analysis assume an immediate purchase in 2016, or do you know?

A. Actually, it assumed a purchase in -- I think it was mid 2014.

Q. Your response just said you think it was. Are you sure of that, or is there something you can check to be sure of that?

A. I would need to check -- let me see if it's in the testimony -- whether it was sort of, you know, the beginning, middle, or end of 2014. I believe that we assumed June 1, 2014, to make it available for, you know, a summer. But I can look and see if I actually gave that number in my testimony or not.

Q. Thank you.

A. It does not appear that I've given that date in the testimony, so I guess we'll have to check, but subject to check, it was in 2014.

Q. Okay. Thank you. You mentioned that the transmission costs had some different assumptions. The "high diff" case, the reference was [redacted] and the "low diff" was [redacted] And comparing those numbers to BMHB-18, the original base line transmission cost associated with Osprey was [redacted]

A. Yes.

Q. And where did that come from?

A. Well, we had done a preliminary estimate of the direct transmission costs, and the transmission modeling team had produced a routing and a cost estimate for that routing. And then we went back to them and said that the costs seemed kind of high. And they said, well, you know, they thought that it was done on a preliminary basis and that there was probably room for improvement. And at that point, they -- well, I don't know exactly when, but shortly after that, they began a more detailed study to identify more cost-effective routing for the lines and subsequently produced the $150 million estimate which is in Mr. Scott's testimony.

Q. Do you know whether Duke has been buying power from Osprey recently?

A. Not specifically. I know that we have not purchased capacity from Osprey. Whether we're buying power in the daily energy market is not in my area.

MR. WRIGHT: Would you like to take a break? I would.

THE WITNESS: Well, I was really hoping to finish your questions before we got to that point, particular, since our fuel transportation experts looked at the gas contract that Osprey currently has and the remaining duration of the contract and the size of the contract and so forth, we did not.

Q. Would it be fair to infer that that is because you thought that was a certain gas transportation contract?

A. Yes.

Q. Looking at BMHB-9, I note that there's a potential negative on the band associated with the Suwannee peakers of what looks to me to be about [redacted] million.

A. Uh-huh.

Q. How would that come about? What conditions would have to occur to result in that being the number?

A. The biggest piece of that negative number was actually the risk of our needing to purchase additional gas transportation. I think if you'll refer again to page --

Q. Thirteen?

A. Yes, to Exhibit 13, on page 20 of 51. I think the same page appears in more than one place, but I happen to have it open to page 20 of 51.

Q. I am there. Thank you.

A. And if you look at the top left of that page, where the base case is listed there, you'll see that there is a -- there are a list of issues that might arise relative to the self-build projects, which include some potential differences in the costs. And if you run your finger down, you'll see that there is an FT differential of [redacted] potentially contemplated.

And again, because at that point, you know, we had what we believed was a good preliminary estimate, but not a final estimate, we were examining potential risks around all the different options, including the self-build option, and considering -- you know, so at that point, we identified the need for additional FT as a potential risk and took that back to our subject matter experts to verify the primary assumption.

Q. Is it your testimony categorically that there is no risk of there being any such firm transportation costs attaching to the Suwannee self-build?

A. Well, let me say it this way. Throughout our estimates, we have repeatedly engaged our subject matter experts to verify that they believe the portfolio is sufficient to support the Suwannee and the Hines builds without additional fixed transportation, and they have repeatedly and consistently told us that that is the case.

Q. I interpret that, the direct answer to my includes the cost of firm gas transportation service for those units?

A. Yes.

Q. If you know, when Duke modeled just the [redacted] what was the backfill unit in 2022?

A. There's a -- I believe there's a single CT called for in 2022, and then I don't know that it affected the term, you know, much beyond that.

Q. If you know, what were the gas transportation costs associated with the backfill unit?

A. I don't have that number off the top of my head.

Q. Does the figure [redacted] in CPVRR sound familiar to you?

A. That sounds like a reasonable ballpark.

Q. Did you ever know Jerry Gunter?

A. No.

Q. I ask because I'm going to ask you some questions about forecasting. Once upon a time when I was on the staff, he said, "Mr. Wright, is that a forecast?"

I said, "Yes, sir."

And he said, "What do we know about forecasts?" He said, "They're going to be wrong." So I the Citrus County plant, did Duke consider postponing half of the Citrus capacity for any period of time, a year or two or three?

A. We did an analysis of postponing the entire capacity by a year. I cannot recall doing an analysis on partial deferral, except to the extent that it was offset by acceptance of some of the other bids. So that would effectively be no.

Q. Did Duke include any value or potential value of deferring part of Citrus in its evaluation of Calpine's July 3rd offer?

A. No.

Q. At page 26 of your direct testimony, you talk about having entered into a short-term power purchase agreement with Southern Company.

A. I'm sorry. Direct testimony in which docket?

Q. Good question. This is the original file. I think it's the 11, but I won't swear to that, Ben. It's page 26.

A. Well, let's look at page 26 and see if we can figure that out.

Yes. All right. That is in 11.

Q. Oh, good. That's what I thought.

Okay. [redacted]

A. Yes, it is.

Q. Okay.

A. Or I guess I should say I was referring to the gas supply to those units.

Q. Okay. With respect to the FERC market issue, do pages 4 and 5 of your Exhibit BMHB-15 present the DEF [redacted]

A. Yes.

Q. Can you tell me at any time, did NRG offer to [redacted]

A. No, they did not.

Q. Did you ask them to?

A. We did not make specific requests of NRG or, for that matter, any of the counterparties. We made them aware of what the issues were in the analyses, as you can see in this exhibit, and looked for their responses to those issues.

Q. Did Duke ever state to NRG that it was willing to submit a filing to FERC for approval of the acquisition of the Osceola project if NRG would hold ratepayers harmless for pursuing the NRG proposal in lieu of the self-build option?

A. As an overall concept, that was brought up in discussion. I don't know that we made that as a specific offer or any kind of a commitment. I would characterize that as having occurred more along the lines of our saying, "In order for us to move forward with any kind of a deal that we would take before FERC, these issues have to be resolved."

Q. With respect to the Calpine proposals, does BMHB-18 present a summary of the CPVRR evaluation comparison for Calpine's final and best offer with the DEF self-build option, subject to that differential assessment that you went over with Mr. Wright?

A. Yes. I mean, it presents our evaluation of their July 3rd offer.

Q. Okay. Am I correct that the CPVRR of the Calpine best and final offer is about [redacted] less cost-effective than the self-build option?

A. Yes.

Q. And am I also correct that the Hines chiller modification is assumed to be implemented in that calculation of the [redacted]

A. Yes. The Hines chiller modifications are assumed to have been implemented in both cases, both the acquisition case and the self-build case.

Q. Okay. Does the [redacted] figure reflect DEF's assumption regarding costs associated with firm gas transportation and transmission service/upgrade requirements necessary to make the Calpine offer comparable with the self-build option?

A. Let me say it differently. The [redacted] analysis, or the analysis that leads to the [redacted] result assumes that sufficient and adequate electrical and gas transmission for integrating the Calpine plant into the system, subject to the lengthy discussion I had with Mr. Wright earlier, would be part of the deal.

Q. Would you agree that a [redacted] difference to the bad is not a significant difference for the type of CPVRR evaluation that DEF performed in these proceedings over the time frame that you were looking at?

A. No. I think I would believe that the [redacted] is a real and material number.

Q. So would you agree that the real economic concern with the latest Calpine offer are the consequences to DEF's customers associated with delaying the Suwannee unit to apply to FERC, and then not obtaining FERC approval of the acquisition?

A. Well, no. I think there are -- you know, there's more than one concern. And referencing our conversation earlier, we have concerns about the economic benefit or the cost-effectiveness of the acquisition as it is structured in Calpine's July 3rd [redacted] acquisition and so forth. We also have concerns about the effect on our customers of the structure where there would be an adverse decision from FERC. And in our conversations with Calpine, we have attempted to identify issues around both of those scenarios.

Q. Well, in that regard, at any time did Calpine [redacted]

A. I don't believe they made us that specific offer.

[redacted]

A. Yes.

[redacted]

a particular discussion of conditions or, you know, other deal structures for the purpose of doing an initial evaluation of what those acquisitions would look like in modeling, which eventually led to the analysis results that are shown in Exhibits 8 and 9 to my direct testimony.

Q. Did you ever receive a Calpine offer to buy Osprey in a timely fashion that would have allowed you to avoid incurring any of the sunk costs that you have modeled for the Suwannee unit?

A. Well, I suppose that had we been able to move immediately on the offers that were made in late 2013, that would be theoretically possible. But in reality, because of the complications of actually consummating such an acquisition, including the FERC market screen issues, that was probably never a reality.

Q. Okay. I think you answered this with Mr. Wright, but let me make sure I understand. Did you ever give an answer about what the impact on the [redacted] CPVRR would be if you could acquire Osprey at an earlier date, for example, in '16?

A. Well, what I had said was that in general, the less time we had under the PPA and the earlier the acquisition occurred, the more beneficial that was from a cost-effectiveness standpoint. So the -- the actual, a deal.

Q. Let's just look at BMHB-18, page 1.

A. Yep.

Q. Can you tell me which of the numbers here would change if DEF could acquire Osprey at the earliest date that Calpine offered to sell it?

A. Yes. The most notable changes here, if we bring the acquisition earlier, would be to the capacity charge number, [redacted] and the wheeling charge number, [redacted] I mean, I think both of those would be decreased substantially, depending on how much forward you bring the acquisition.

Q. [redacted]

A. [redacted] I'm sorry. I misspoke.

Q. That's okay. And I got lost in the [redacted] thing. What was the other number? The wheeling?

A. The wheeling charge number, which is directly below that.

Q. [redacted] Okay. Are there any others?

A. Well, if I can remember what I've looked at. I mean, those are the principal ones. There may be some other puts and takes around some of the production costing, but in general, those are the big numbers.

Q. Okay. Were there any that would have gone the other direction?

A. The only one that would go the other direction at all is -- I mean, in fairness, this doesn't really go the other direction. It's more about the way we did the puts and takes. But you can see that [redacted] there that's the FOM costs offset by the PPA.

Q. Yes.

A. And what that number reflects is that in our original estimate, the one that I referenced in Exhibit 8, we assumed that we would be -- you know, we, DEF would begin operating the plant in 2014, so we picked up fixed operating cost numbers for those years.

So when we did the analysis that's shown here on this exhibit, where the acquisition was moved back to 2020, you know, obviously, we were paying Calpine to operate the plant during those intervening years under the PPA, so we credited -- as we were doing puts and takes, we credited back that value that we had originally put in our costs under the early acquisition.

Q. Okay. And the --

A. So there would be some --

Q. Go ahead.

A. There would be some puts and -- I guess I would say there would be some puts and takes to the adjustments. But in general, at eye level, what we have found is that bringing the acquisition forward is better, you know, for a number of the reasons. I mean, certainly the reduction in the capacity and wheeling charges is one. The access to the full capacity of the plant because of earlier completion of the transmission is another. So there are definite benefits that come from completing that acquisition earlier if it could be done.

Q. Okay. Let's see. [redacted]

A. It is. But I would hesitate to suggest that it's as simple as that math when you readjust the whole production model.

Q. Okay. Is there any way to ballpark where this would be in a conservative fashion that would kind of keep you within the production modeling adjustments that you might also see?

A. I guess it's fair to say that we have ballparked that there's a potential positive CPVRR value if we could get to a 2016 acquisition, but there are still a number of uncertainties, the primary one which is around the FERC issue.

Q. Right. So setting aside the FERC issue, what is that ballpark number?

A. I don't have that number off the top of my head for you, Charles.

A. The number in that cell indicates that we modeled that we would burn [redacted] worth of gas in Unit 1 of the Osceola units during 2014.

Q. So to the right of that, all the cells would be the burns for that year, the indicated year; correct?

A. Yes.

Q. Okay. How were those numbers produced?

A. These numbers are produced as the results of our dispatch model using the costs, the operating costs and information, heat rates and so forth, provided to us by Osceola.

Q. So you input those numbers into your model, and it produces --

A. Right. It dispatches the entire fleet and dispatches different units relative to their assigned costs, which include variable operating costs, start costs, emissions values, heat rates, and so forth.

Q. And so in order to look behind that, I would have to have access to the calculations in the model?

A. Well, I mean, you could gain a substantial understanding of what's going on with a review of the inputs, but typically to identify the absolute specifics of how a number is calculated, you would have to have access to the model or the opportunity to, you know, experiment with the model by adjusting the inputs.

MR. WALLS: Same objection.

BY MS. RULE:

Q. If you know.

A. Well, I'll take a stab at that question. I think the point here is that Duke has a portfolio of a number of contracts, some of which are quite old, and some of which are more recent. And, you know, we are also in the process of negotiating forward-looking contracts, you know, for instance, for our Citrus combined cycle. Each one of those contracts, based on the time at which it is signed and the terms of the negotiation with the gas transporter, has a different price. The $1.50 that you're referring to was estimated based on the current pricing for new capacity posted by FGT.

Q. Do you have a figure for Calpine per decatherm?

A. Well, Calpine has an existing contract which was negotiated, I believe, in 2003, or maybe 2002. And I believe that contract was negotiated at [redacted] a decatherm. But as I say, that price is not available today. That was the price that they got then.

Q. How much gas is needed to run all of Duke's gas-fired units at peak capacity for 24 hours?

A. I don't know.

hear out NRG's perspective on the same issues from their experts.

Q. And during the course of those discussions, was a proposed PPA to acquisition structure discussed?

A. It was discussed, and I guess eventually resulted in the proposal that was made by NRG in June.

[redacted]

A. Yes.

[redacted]

A. Yes.

[redacted]

[redacted]

[redacted]

REDACTED

[redacted]

[redacted]

REDACTED

[redacted]

[redacted]

going to build a single CT in 2022, assuming the construction of combined cycles in between. So, you know, there were some pluses and minuses to the different portfolios.

Q. I'm sorry. I was on mute because my cellphone is ringing over here, so you just might have to tolerate that noise in the background.

Is it your testimony that NRG, as a bidder to meet Duke's generation capacity needs, should bear all the sunk costs that Duke has incurred associated with the competing Suwannee project?

A. That has been a consideration in our evaluation of the -- or perhaps our consider -- our evaluation of offers made late in the process since the May time frame. It was not, obviously, a consideration in the evaluations that we conducted in January and February prior to the need to start those projects.

Q. And what types of sunk costs has Duke incurred associated with its proposed Suwannee project?

A. The current value that we have represented is that we have incurred approximately [redacted] in costs to date. The lion's share of those costs are associated with the early turbine payments for the Suwannee turbines.

Q. And were those payments made prior to February of 2014?

A. No.

Q. When were they made?

A. I believe that they began in [redacted]

Q. Do you recall when the contract was entered into associated with those costs?

A. I do not. I don't know.

Q. Is it your testimony that Duke is incurring costs for a turbine for the proposed Suwannee project prior to obtaining Commission approval for moving forward with that project?

A. Yes.

Q. And if Duke's analysis revealed that a project other than the proposed Suwannee project was the most cost-effective generation alternative to meet its customers' needs, who would bear those sunk costs?

A. I don't know specifically. That would be a matter of negotiation between us and the counterparties, and presumably approval by the Commission.

Q. Let's go to your rebuttal testimony on page 6. You state there that Mr. Dauer claimed the ability to operate the Osceola plant on nonfirm and spot market gas transportation arrangements.

A. That is my understanding of his testimony.

Q. Is it your testimony that Mr. Dauer is negative [redacted] CPVRR value.

A. Yes.

Q. The question was whether it was fair to view that [redacted] negative CPVRR value on page 2 of 3 of BMHB-18 in your rebuttal testimony as the risk of an FERC adverse decision. Do you recall that?

A. Yes.

Q. I believe you said yes; right?

A. Yes. Well, perhaps I should say that is the consequence of an adverse decision in this scenario.

Q. And does that pick up all the costs that would be incurred as a result of a FERC adverse situation? And in particular, I'm going to refer you to page 1 at the bottom.

A. Well, in the case that you're talking about here, the assumption here is that the FERC decision would be rendered early enough that we would be able to resume the Suwannee project with only a single year's delay. So the only cost that's over here on the first page that would relate to that that I can think of is the actual cost of the FERC filing, because the deferral of the Suwannee project by the year, there are certainly costs associated with that, and those are accounted for here on page 2. So that cost is, you know, picked up, here, and the assumption is that we would recapture --

REDACTED

except for that adjustment, we would recapture the lion's share of sunk costs associated with the payments that have already been made.

Q. But not all of the sunk costs; right?

A. No, not all. But again, I think the attempt was to account for that "not all" in the [redacted] CPVRR adjustment that you see on page 2.

Q. Okay. And you were also asked a question by Mr. Wright about if you had asked Mr. Scott if he could obtain the 515-megawatt plant capacity for the Osprey plant during firm peak times, and you had referred to the TEC significant upgrade cost to make it available on peak. Do you recall that?

A. Yes.

Q. Is it just a cost issue, or is there another issue related to obtaining the 515 megawatts prior to 2010?

A. Well, there is definitely a construction timing issue. As I was discussing it with Mr. Wright, we were talking specifically about costs. But it also true that if we were to ask or negotiate with TEC to make those upgrades there, they have estimated, I think, somewhere in the vicinity of four to five years to do the upgrades on their system.

Q. Okay. And in connection with that as well,

ATTACHMENT C

DUKE ENERGY FLORIDA
DOCKET NO. 140110-EI
Sixth Request for Confidential Classification
Confidentiality Justification Matrix

DOCUMENT	PAGE/LINE/ COLUMN	JUSTIFICATION
Deposition of Benjamin M.H. Borsch, August 11, 2014	Page 15, Line 13 in its entirety, Line 18, 3rd and 4th words, Line 23, last two words; Page 16, line 6, fifth word, Line 11, first two words, Line 16, fifth and sixth words, Line 18, fourth and fifth words; Page 17, Line 8, fourth and fifth words, Line 9, fifth and sixth words, Line 15, eight and ninth words, Line 23, first two words, Line 25, third and fourth words; Page 18, Line 12, seventh and eighth words, Line 18, seventh word; Page 22, Line 8, last two words, Line 11, second and third words; Page 24, Line 4 in its entirety, Line 6, last two words; Page 25, Line 3, second and third words from end, Line 8, first two words, Line 22, second and third words; Page 26, Line 12, first two words, Line 18, all words except last two; Page 27, Line 4, sixth and seventh words, Line 22, first two words; Page 28, Lines 2 through 4 in their entirety, Line 6, third and fourth words, Line 7, fourth and fifth word, Line 8, third through sixth words, Line 11, fourth and fifth words, Line 12, fifth and sixth words, Line 20, first two word; Page 29, Line 4, fourth and fifth words, Line 8, last two	§366.093(3)(a), Fla. Stat. The document in question contains proprietary confidential information relating to trade secrets, the disclosure of which would impair DEF's business operations. §366.093(3)(d), Fla. Stat. The document portions in question contain confidential contractual information, the disclosure of which would impair DEF's efforts to contract for goods or services on favorable terms. §366.093(3)(e), Fla. Stat. The document portions in question contain confidential information relating to competitive business interests, the disclosure of which would impair the competitive business of the provider/owner of the information.

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DOCUMENT	PAGE/LINE/ COLUMN	JUSTIFICATION
	words, Line 10, all words; Page 30, Line 20, all words; Page 31, Line 19, last two words; Page 32, Line 4, six and seventh words, Line 11, second and fourth words from end, Line 14, fourth and fifth words, Line 15, second and third words from end, Line 16, second and third words, Line 17, last two words; Page 33, Line 2, last two words; Page 34, Line 8, all words except last word, Lines 17, 18 and 19, all words, Line 22, fourth and fifth words, Line 23, first two words; Page 35, Line 1, second and third words from end, Line 3 through 20, all words, Line 23, all words; Page 36, Line 12, second and third words; Page 37, Line 21, first four words; Page 41, Line 4, fourth and fifth words, Line 6, sixth and seventh words, Line 7, second through fifth words, Line 16, last eight words, Line 17 and 18, all words; Page 52, Line 1, second and third word from end, Line 11, first two words; Page 54, Line 15, last two words; Page 56, Line 2, third word, Line 6, last word, Line 8, third word, Line 15, third and fourth words; Page 57, Line 5, first two words, Line 15, all words, Lines 20 through	

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	23, all words, Line 25, last two words; Page 58, Line 2, third and fourth words from end, Line 24, seventh word, Line 25, third word; Page 59, Line 2, last word; Page 65, Line 11, last word; Page 66, Line 6, third and fourth words; Page 69, Line 5, first four words, Line 14, fourth and fifth words; Page 79, Line 24, all words except first word; Page 98, Lines 6 through 9, all words, Lines 12 through 15, all words; Page 99, Line 18, second and third words from end, Line 23, last two words; Page 100, Line 2, fourth and fifth words, Line 7, last two words, Line 8, last two words, Line 13, second and third words from end, Line 19, first two words; Page 101, Lines 5, 12 through 15, 18, 19, and 21 through 25, all words; Page 103, Line 20, first two words; Page 105, Line 9, third through sixth words, Line 10, fourth through seventh words, Line 14, all words; Line 15, first two words, Line 16, last word, Line 20, first word; Page 106, Line 5, last three words; Page 107, Line 9, last six words; Page 128, Line 2, sixth and seventh words; Page 140, Line 20, second and third words from end; Page 145, Lines 7 through	

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DOCUMENT	PAGE/LINE/ COLUMN	JUSTIFICATION
	9, Lines 11, 12 and 14 through 25 in their entirety; Pages 146 through 151 in their entirety; Page 153, Line 21, third and fourth words from the end; Page 154, Line 4, last three words; Page 181, Line 1, second and third words, Line 4, second and third words; Page 182, Line 6, last two words	