BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

FILED 5/17/2018
DOCUMENT NO. 03713-2018
FPSC - COMMISSION CLERK

In the Matter of:

DOCKET NO. 20170260-EI

PETITION FOR LIMITED PROCEEDING TO APPROVE FIRST SOLAR BASE RATE ADJUSTMENT (SOBRA), EFFECTIVE SEPTEMBER 1, 2018, BY TAMPA ELECTRIC COMPANY.
_________________________________/

VOLUME 1
PAGES 1 through 209

PROCEEDINGS:	HEARING
COMMISSIONERS PARTICIPATING:	CHAIRMAN ART GRAHAM COMMISSIONER JULIE I. BROWN COMMISSIONER DONALD J. POLMANN COMMISSIONER GARY F. CLARK COMMISSIONER ANDREW G. FAY
DATE:	Tuesday, May 8, 2018
TIME:	Commenced: 1:30 p.m. Concluded: 5:25 p.m.
PLACE:	Betty Easley Conference Center Room 148 4075 Esplanade Way Tallahassee, Florida
REPORTED BY:	DEBRA R. KRICK Court Reporter

PREMIER REPORTING
114 W. 5TH AVENUE
TALLAHASSEE, FLORIDA
(850) 894-0828

APPEARANCES:

JAMES D. BEASLEY, and J. JEFFRY WAHLEN, ESQUIRES, Ausley & McMullen, Post Office Box 391, Tallahassee, Florida 32302, appearing on behalf of Tampa Electric Company.

JON C. MOYLE, JR., and KAREN PUTNAL, ESQUIRES, Moyle Law Firm, P.A., 118 North Gadsden Street, Tallahassee, Florida 32301, appearing on behalf of Florida Industrial Power Users Group.

J.R. KELLY, PUBLIC COUNSEL; CHARLES REHWINKEL, DEPUTY PUBLIC COUNSEL; Office of Public Counsel, c/o the Florida Legislature, 111 W. Madison Street, Room 812, Tallahassee, Florida 32399-1400, appearing on behalf of the Citizens of the State of Florida.

WALTER TRIERWEILER, KURT SCHRADER, AND JENNIFER CRAWFORD, ESQUIRES, FPSC General Counsel's Office, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing on behalf of the Florida Public Service Commission Staff.

KEITH HETRICK, GENERAL COUNSEL; MARY ANNE HELTON, DEPUTY GENERAL COUNSEL; JENNIFER CRAWFORD, ESQUIRE, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, Advisor to the Florida Public Service Commission.

I N D E X

WITNESSES

EXHIBITS

NUMBER:		ID	ADMITTED
1	Comprehensive Exhibit List	7	7
2-12	As identified on the comprehensive exhibit list		8
13	FPL's Response to Staff's Third Set of Interrogatories, No. 24	38	
14	NREL Q1 2016 Benchmark Report Excerpt	38	
15	2017 Agreement	40	104

P R O C E E D I N G S

CHAIRMAN GRAHAM: Okay. Good afternoon, everyone.

COMMISSIONER BROWN: Good afternoon.

COMMISSIONER POLMANN: Good afternoon.

CHAIRMAN GRAHAM: Let the record show it is Tuesday, May 8th still. It is 1:30 in the afternoon, and this is a hearing for Docket 20170260-EI.

We will convene this hearing, and if I can get staff to read the notice, please.

MR. TRIERWEILER: By notice issued April 16, 2018, this time and place was set for this hearing in Docket No. 20170260-EI. The purpose of this hearing is set out in the notice.

CHAIRMAN GRAHAM: Okay. Let's take appearances. Let's start with TECO.

MR. WAHLEN: Afternoon, Commissioners. I am Jeff Wahlen appearing with Jim Beasley, of the Ausley McMullen law firm, P.O. Box 391, Tallahassee, Florida, on behalf of Tampa Electric Company.

MR. MOYLE: Good afternoon, Mr. Chairman. Jon Moyle with the Moyle Law Firm appearing on behalf of the Florida Industrial Power Users Group, and I would also like to enter an appearance for Karen Putnal with our firm.

MR. REHWINKEL: Good afternoon, Mr. Chairman, Commissioners. Charles Rehwinkel, Deputy Public Counsel. Appearing here with me is J.R. Kelly, Public Counsel. And at the table with me is Marshall Willis from the Public Counsel's office.

MR. TRIERWEILER: Good afternoon. I am Walt Trierweiler, and together with Kurt Schrader, we represent the Commission staff.

MS. HELTON: And Mary Anne Helton here as advisor. I would also like to enter an appearance for your General Counsel, Keith Hetrick.

CHAIRMAN GRAHAM: Okay. Welcome all.

Preliminary matters, staff.

MR. TRIERWEILER: There are none.

CHAIRMAN GRAHAM: Stipulations.

MR. TRIERWEILER: There are none.

CHAIRMAN GRAHAM: Exhibits.

MR. TRIERWEILER: Staff has prepared a comprehensive exhibit list, which includes the prefiled exhibits attached to the witnesses' testimony, as well as staff exhibits.

The list itself has been previously identified as Exhibit 1 and has been provided to the parties, Commissioners and the court reporter. Staff requests that the list be marked as Exhibit 1 for the record.

CHAIRMAN GRAHAM: We will mark that exhibit as Exhibit 1.

(Whereupon, Exhibit No. 1 was marked for identification.)

MR. TRIERWEILER: At this time, staff would request that Exhibit No. 1 be entered into the record, and that all other exhibits be marked as identified therein.

CHAIRMAN GRAHAM: We will enter Exhibit 1 into the record.

(Whereupon, Exhibit No. 1 was received into evidence.)

CHAIRMAN GRAHAM: Are we also entering Exhibits 2 through 12?

MR. TRIERWEILER: That is correct. We have a stipulation to the admissibility of the comprehensive exhibit list, and those are Exhibits 2 through 12, which we request to be moved in.

CHAIRMAN GRAHAM: Any concerns or questions about entering Exhibits 2 through 12 into the record?

MR. REHWINKEL: None.

MR. WAHLEN: None.

CHAIRMAN GRAHAM: Let the record show there is no objections, so we will enter two through 12 into the record.

(Whereupon, Exhibit Nos. 2 - 12 were received into evidence.)

CHAIRMAN GRAHAM: All right. Let's click along.

Opening statements.

MR. WAHLEN: Thank you, Commissioners --

CHAIRMAN GRAHAM: You have five minutes.

MR. WAHLEN: Good afternoon. Today, Tampa Electric Company seeks approval of its first solar base rate adjustment for two solar projects totaling approximately 145 megawatts. The Payne Creek project is approximately 70.3 megawatts, and has a projected installed cost of $1,324 per kilowatt AC. The Balm project is 74.4 megawatts, with a projected installed cost of $1,480 per kWac. The projected weighted average installed cost for the two projects together is approximately $1,404 per kilowatt AC.

The company seeks approval of this first SoBRA pursuant to order number PSC-20170456, issued November 27th, 2017. That order approved the 2017 amended and restated stipulation and settlement agreement between Tampa Electric, Office of Public Counsel, FIPUG and other consumer parties. We refer to that agreement as the 2017 agreement throughout the company's testimony, and will refer to it that way during the hearing today.

Paragraph six of the 2017 agreement creates a path for approval of solar projects and solar base rate adjustments. Paragraph six was carefully negotiated to allow the company to build and get cost recovery for solar projects that meet specified criteria.

One criteria requires that the projects together must be cost-effective as assigned -- as defined in the agreement. Another requires that the individual projects have an installed cost of less than $1,500 per kilowatt AC. It also specifies the rate design criteria to be used to recover the cost of the solar projects.

All of the cost data you will be hearing today is projected data that will be trued up in the future in SoBRA proceedings once the final actual numbers come in.

Tampa Electric Company will present three witnesses today, Mr. Mark Ward will describe the two projects, explain the steps the company has taken to bring the project -- projected installed costs of the projects as far below the $1,500 cap as possible, and he will also explain what the costs are, and that they are under the cap.

Mr. Ward then will hand off to Mr. James Rocha, who will show that the two projects in the first SoBRA satisfy the cost-effectiveness test in the 2017 agreement. He will also present the annual revenue requirement needed to recover the projected costs of the two projects in accordance with these 2017 agreement.

Finally, using the annual revenue requirements calculated by Mr. Rocha, Mr. Ashburn will present evidence supporting the customer rate changes and tariffs for the first SoBRA to be effective September 1st of this year.

Once our three witnesses have testified and the exhibits are in the record, Tampa Electric is confident that it will have made its burden of prove for the first SoBRA.

Thank you.

CHAIRMAN GRAHAM: Thank you.

OPC.

MR. REHWINKEL: Thank you, Mr. Chairman, and

Commissioners.

The Public Counsel is here today in apparent opposition to the first solar projects that Tampa Electric is proposing under the agreement that this office and other intervenors entered into in 2017 with the company. This agreement was historic because it is essentially a four-year base rate freeze and a four-year solar generation build-out opportunity that is intended to have a transformative impact on Tampa Electric's generation profile.

As he said, when the settlement was signed and approved, the Public Counsel believed then, and believes now, this agreement to be in the public interest.

When adopted by the Commission, the agreement became the Commission's policy for base rate recovery for Tampa Electric for the next four years. That means that all of the provisions within it must be honored and adhered to.

The Commission has already had an opportunity to partially implement specific provisions when it considered and approved an implementation stipulation among the signatories to preliminarily address the recovery of 2017 hurricane damage costs and the prompt return of tax savings. The Public Counsel firmly believes that the initial implementation of those provisions adhered to the letter of the agreement.

This case today, likewise, will be something of a preliminary implementation of a major provision of the agreement that will, like the preliminary implementation of the storm and tax provisions, be subject to a final accounting and true-up.

Commissioners, even though it is a preliminary implementation, it is important to get it right and to follow the provisions of the agreement, so that the rates the customer will pay, if the projects are approved, will be the lowest they are entitled to pay for the service they will receive from those solar facilities.

The public counsel has taken positions in the prehearing statement that are in opposition to the company, we believe that the company must make its case measured against the standards contained in paragraph six of the agreement.

The Public Counsel will cross-examine the company witnesses to determine if the evidence that the company has put forward meets the test set out in the agreement.

And this is the important part: At the conclusion of the evidence in this case, we will ask you for a brief recess, followed by an opportunity to address the Commission in closing statements. If we are satisfied that the provisions of the agreement are met by the evidence put on, the Public Counsel will be prepared to state that and waive briefing so that if the Commission is so inclined a bench vote can be held at the conclusion of this case.

Thank you.

CHAIRMAN GRAHAM: Thank you.

Mr. Moyle.

MR. MOYLE: Thank you, Mr. Chairman.

I am going to give you my opening comments, but I just want to share with the Commission, if I could for a minute, that I had an opportunity last week to have some unintended reflection time as a result of miscalendaring -- I miscalendared the prehearing conference.

And I want to say I had some reflection time, because this is a small bar that practices before you regularly, and I was so grateful that so many people, lawyers, staff, others were concerned about my well-being and reached out to me. I was well, but I goofed, and I am sorry for that, and we've addressed it. But I wanted to thank everyone for their graciousness in dealing with an error that was my fault. So I wanted to do that on the record. Public Counsel carried the order for me, so anyway, my apologies to the Commission for that miscalendaring that I was responsible for.

To talk about the SoBRA issue, my client, the Florida Industrial Power Users Group, I don't think it's a secret, has not been wild about the SoBRA concept. This is the second time, I believe, that you will be hearing about this issue. The first was in Florida Power & Light, and we contested the SoBRA issues at hearing.

We did not have a settlement agreement signed with Florida Power & Light. This case is somewhat different in that we do have a settlement agreement, and we, as you would expect, will honor our settlement agreement and ask questions we believe in accord with the settlement agreement, which allows questions about cost-effectiveness, and we are going to ask questions about the incentive mechanism, which is a unique component of the Tampa Electric SoBRA component; ask some questions about solar trends, because I think, as I stated, but I just want to reiterate, that my client's position with respect to renewable energy is that we support renewable energy. And there is a lot of different kinds of renewable energy, you know, solar, wind is talked about a lot, but there is also biomass renewable energy, and a whole array of solar energy. And we believe that solar energy should be pursued under two conditions, if it's cost-effective and if it is needed.

So those are kind of the polestars that FIPUG has set forth with respect to SoBRA.

Again, our questions will be respectful of the settlement agreement. And while we have taken positions in opposition, like Public Counsel, we also want to have some of the facts adduced during this hearing to make sure they are carrying their burden of proof, and that -- ask for a break at the end of the hearing, I think, will be helpful so we can consider whether we want to file briefs or waive the filing of briefs.

So, again, thank you -- thank you for the chance to be here and present FIPUG's position. I appreciate it.

CHAIRMAN GRAHAM: Thank you, Mr. Moyle.

Okay, that's opening statements.

Witnesses -- this is mainly for the attorneys. You guys all know because you have all been here many times before. There is no friendly cross.

For the witnesses, when you are asked a question, please try your best to answer it yes or no, and we will give you a brief period to explain the yes or no. If you can't answer yes or no, or you don't understand the question, you can ask them to repeat it, or maybe you can restate it back the way you understand it and go from there.

I will let you editorialize as long as you want. It's going to be controlled by the person actually asking you the questions. So those attorneys that are cross-examining, if you just want them to say a simple yes or no and a brief sentence or two, then I will allow you to control that. If you want him to elaborate, then I will let you guys make that call. And after you object the first time, I will make sure that they adhere to it more stringently from that time on.

That's all I have.

If you are a witness here that is going to speak today, if I can get to you stand and raise your right hand, please, so I can swear you in.

(Whereupon, all witnesses present were sworn.)

CHAIRMAN GRAHAM: Thank you.

Okay. TECO, let's call your first witness.

MR. WAHLEN: Thank you, Mr. Chairman. Tampa Electric company calls Mr. Mark Ward.

Whereupon,

MARK WARD

was called as a witness, having been previously duly sworn to speak the truth, the whole truth, and nothing but the truth, was examined and testified as follows:

EXAMINATION

BY MR. WAHLEN:

Q Good afternoon. Could you please state your full name for the record?

A Mark D. Ward.

Q Mr. Ward, have you been sworn?

A I have.

Q And who is your current employer, and what is your business address?

A My employer is Tampa Electric. My business address is 702 North Franklin Street, Tampa, Florida.

Q And did you prepare and cause to be filed in this docket on December 14th, 2017, prepared direct testimony consisting of 16 pages?

A I did.

Q Do you have any corrections to that testimony?
A I do.
Q Would you please point out the page and line number for your correction?
A Page six, line 25, I would like to insert in lieu of 150 megawatts, approximately 145 megawatts.
Q Okay. Any other changes?
A No. Thank you.
Q With that one change, if I were to ask you the questions contained in your prepared direct testimony today, would your answers be the same as those contained in the document?
A They would.
MR. WAHLEN: Mr. Chairman, Tampa Electric company requests that the prepared direct testimony of Mr. Mark Ward, dated December 14th, 2017, with the one correction be inserted into the record as though read.
CHAIRMAN GRAHAM: We will insert Mr. Ward's prefiled direct testimony with the one change into the record as though read.
MR. WAHLEN: Thank you.
(Whereupon, prefiled direct testimony was inserted.)

TAMPA ELECTRIC COMPANY
DOCKET NO. 2017____-EI
FILED: 12/14/2017

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

MARK D. WARD

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

A. My name is Mark D. Ward. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director of Renewables.

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

A. I earned a Bachelor of Science in Mechanical Engineering from University of Alabama in Huntsville in 1984. I have 33 years of combined professional experience as a Department of Defense contractor, and working for public utilities and independent power producers. Twenty-one years of my experience has been with electric utilities and independent power producers.

I worked for Tampa Electric from 1996 to 2001 where I served as Manager of Generation Planning and provided management support for the development of Tampa Electric’s Bayside Power project. From 2001 to 2007 I served in mid- to senior level management positions at various companies involved in the power industry. These companies included; Entergy Asset Management, an unregulated subsidiary of Entergy, the Shaw Group, an engineering and construction firm, and TXU, a regulated electric utility. From 2007 to 2014 I served as President of the Mesa Power Group. Mesa Power was a renewable energy developer with a primary focus in large scale wind development. From 2014 to 2016 I managed an energy consulting practice with clients primarily in solar, wind and combined heat and power.

I was re-hired by Tampa Electric in December 2016 as Director of Renewables. My responsibilities in this position include management oversight with respect to Tampa Electric’s renewable energy strategies and projects. This includes the execution of Tampa Electric’s 600 MW of utility scale solar projects described in the 2017 Amended and Restated Stipulation and Settlement Agreement (“2017 Agreement”) that was approved by the Commission in Order No. PSC-2017-0456-S-EI, issued in Docket Nos. 20170210-EI and 20160160-EI on November 27, 2017.

Q. Have you previously testified before the Commission?

A. Yes. I submitted direct and rebuttal testimony on behalf of Tampa Electric in Docket No. 19981890-EI (In re: Generic Investigation into Aggregate Electric Utility Reserve Margins Planned for Peninsular Florida). I submitted direct and rebuttal testimony on behalf of Tampa Electric on the prudency of replacement fuel and purchased power costs in Docket No. 19990001-EI (In re: Fuel and Purchased Power Cost Recovery Clause and Generating Performance Incentive Factor). I submitted direct testimony on behalf of Tampa Electric regarding the Gannon Repowering Project in Docket No. 19992014-EI (In re: Petition by Tampa Electric Company to Bring Generating Units into Compliance with Clean Air Act).

In addition, while working for Mesa Power Group, LLC, I submitted direct testimony before the Minnesota Public Utilities Commission on behalf of AWA Goodhue, LLC in MPUC Docket No. IP6701/WS-08-1233 (In the matter of the Application by AWA Goodhue Wind, LLC for a Site Permit for a Large Wind Energy Conversion System for a 78 MW Wind Project in Goodhue County).

I also served as a member of a panel of witnesses during the November 6, 2017 hearing on the 2017 Agreement.

Q. What are the purposes of your direct testimony?

A. The purpose of my direct testimony is to: (1) explain the company's plans to build solar photovoltaic generating facilities to serve its customers; (2) describe the company's first two new solar projects ("Tranche One Projects") expected to be in service by September 1, 2018; and (3) demonstrate that the projected installed costs for the two Tranche One Projects are below the $1,500 per kilowatt alternating current ("kW_{ac}") installed cost cap contained in the 2017 Agreement.

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

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

Document No. 1	Payne Creek Solar Project Specifications
Document No. 2	Payne Creek Solar Project General Arrangement Drawing

Document No. 3	Payne Creek Solar Project Projected Installed Cost by Category
Document No. 4	Balm Solar Project Specifications
Document No. 5	Balm Solar Project General Arrangement Drawing
Document No. 6	Balm Solar Project Projected Installed Cost by Category

Q. How does your prepared direct testimony relate to the prepared direct testimony of the company's other two witnesses?

A. My prepared direct testimony describes the two Tranche One Projects (Payne Creek Solar and Balm Solar) for which cost recovery is requested via the company's First Solar Base Rate Adjustment ("SoBRA") as well as their projected in-service dates and installed cost per KW_{ac}. Tampa Electric witness R. James Rocha uses the projected installed project cost in my direct testimony to calculate the annual revenue requirement for the First SoBRA. The company's cost of service and rate design witness, William R. Ashburn, uses the annual revenue requirement to develop the proposed customer rates for the First SoBRA.

Tampa Electric's Solar Plans

Q. Please describe the company's overall plan to install solar photovoltaic ("PV") generating facilities.

A. Over the next four years, Tampa Electric plans to add 6 million solar modules in 10 new solar PV projects across its service territory in West Central Florida. This amounts to a total of 600 megawatts ("MW") of cost-effective solar PV energy, which is enough electricity to power more than 100,000 homes. When the projects are complete, about six (6) percent of Tampa Electric's energy will come from the sun.

These solar additions are a continuation of Tampa Electric's longstanding commitment to clean energy. The company has long believed in the promise of renewable energy because it plays an important role in our energy future. As a member of the Emera family, Tampa Electric is committed to transitioning its power generation to lower carbon emissions with projects that are cost-effective for customers.

The 600 MW of cost-effective solar PV will be added to the company's generating fleet in four tranches. The company plans ~~150~~ approximately 145 MW of PV solar generation with an in-

DK

service date of September 1, 2018, another 250 MW in service as of January 1, 2019, another 150 MW in service by January 1, 2020 and 50 MW in service by January 1, 2021.

The focus of my direct testimony is the company’s planned first tranche, which consists of two projects totaling 145 MW with a projected in-service date of September 1, 2018.

Tranche One Projects: Payne Creek Solar and Balm Solar Projects

Q. Please describe the two Tranche One Projects.

A. The two projects in Tranche One are known as the Payne Creek Solar and Balm Solar Projects. The projects are single axis tracking systems, each designed to produce optimal MW of energy for the particular site conditions. The 70.3 MW Payne Creek Solar Project is located in Polk County, Florida on reclaimed phosphate mining land. The 74.4 MW Balm Solar Project is located in Hillsborough County, Florida on agricultural land. My Exhibit No.____(MDW-1) contains project specifications, a general arrangement drawing and projected installed costs in total and by category for each project.

Q. When does the company expect the Tranche One Projects to begin commercial service?

A. Based on the current engineering, procurement and construction ("EPC") schedules, the company expects both projects to be complete and in service on or before September 1, 2018.

Q. What arrangements has the company made to design and build the Tranche One Projects?

A. The company used a competitive process to review qualifications and experience and identify and select full-service solar developers. Three full-service solar developers were selected to enter into contract negotiations to provide project development and EPC services for the 600 MW of Tampa Electric solar projects.

Tampa Electric employed a Request for Information ("RFI") process to collect information from the bidders with respect to their qualifications, capabilities and experience as full-service solar developers. The RFI was provided to more than 60 companies with whom Tampa Electric had met or discussed the development and construction of utility scale solar projects. Tampa

Electric received more than 30 responses from solar developers or solar EPC companies. The company used the information from the RFI responses to select a shortlist of four full-service solar developers.

The shortlisted developers were asked to provide pricing for seven solar PV projects that ranged in size from 20 to 74.5 MW_{AC}. The pricing information was broken out for engineering and permitting, equipment, balance of system, installation and interconnection. The projects were based on sites that Tampa Electric has purchased or for which it has site control. During the pricing phase of the selection process one developer withdrew. The pricing evaluation was conducted during May 2017 and included interviews with each developer.

In early June 2017, Tampa Electric selected First Solar Electric, LLC as its full-service solar developer and EPC contractor for the Tranche One projects. First Solar Electric was selected based on its qualifications, experience and proposed project costs. First Solar Electric is based in Tempe, Arizona and has engineered, developed and installed more than five (5) gigawatts of solar generation worldwide.

Q. Has the company procured the land necessary for the solar projects?

A. Yes, Tampa Electric has purchased land for the two projects. Tampa Electric employed a screening and due diligence process to select its solar sites. The Payne Creek and Balm sites were evaluated and selected after considering environmental assessments, size of the project sites, proximity to Tampa Electric transmission facilities, cost of land, and suitability of the sites for solar PV construction. The two sites are each approximately 500 acres in size.

Q. What is the status of project design and engineering for the Tranche One Projects?

A. The Payne Creek and Balm projects are being engineered and designed, with documentation and permit applications being completed. Long lead time equipment is being procured, and meetings are being scheduled and held with Hillsborough and Polk Counties and the Florida Department of Environmental Protection. The company expects design and permitting for the projects to be complete in early 2018.

Q. Has the company purchased PV modules necessary to construct the projects?

A. Yes. The company has entered into a contract for the purchase of PV modules (i.e., solar panels) from First Solar, Inc. First Solar is obligated to complete the delivery of the modules needed for the Payne Creek Solar and Balm Solar Projects before August 6, 2018. The delivery of modules to the projects will be staged over several weeks between May 2018 and August 6, 2018 to ensure the projects are operational by September 1, 2018.

Q. What other procedures did the company use to ensure that the costs of the projects are reasonable?

A. Tampa Electric's primary procedure used to ensure that the costs of the projects are reasonable was the RFI process. The four shortlisted candidates were selected from the 30 respondents to the RFI. Each of the four candidates were provided several sites that Tampa Electric had purchased or controlled and were asked to provide proposals for the specific sites. The proposals were reviewed, and meetings were held with the candidates. The cost proposals submitted by the candidates for Payne Creek and Balm were within five and seven percent of one another, respectively.

Tampa Electric also monitors published costs of other projects, particularly those in Florida. The Tampa Electric project costs compare favorably to the costs of those projects. Lastly, Tampa Electric occasionally receives unsolicited proposals from developers. The company's solar projects compare favorably to these proposals.

Q. Are the costs of the solar modules to be used in the Tranche One projects subject to increase from tariffs or import duties?

A. No. In a recent Section 201 Trade Case, the United States International Trade Commission found that solar module manufacturers Suniva and SolarWorld suffered economic injury by solar modules from overseas, which could result in the future imposition of tariffs or import duties on certain solar modules manufactured outside the United States. Tampa Electric has mitigated its exposure to this potential cost increase by executing a module purchase agreement with U.S. manufacturer First Solar, Inc. for 600 MW of modules at prices that are competitive with module prices prior to the Suniva filing. This will ensure that Tampa Electric's Tranche One projects are competitive, even if the Suniva Section 201 Trade Case results in the imposition of tariffs or import duties.

Projected Installed Costs

Q. What are the projected installed costs for the Tranche One Projects?

A. The projected installed costs of the Payne Creek and Balm Solar Projects are $1,324 kW_{ac} and $1,480 kW_{ac}, respectively.

Q. What costs were included in these projections?

A. The projected total installed cost broken down by major category for the Tranche One Projects are shown on Document Nos. 3 and 6 of my exhibit.

The projected costs shown in my exhibit reflect the company's best estimate of the cost of the projects; they include the types of costs that traditionally have been allowed in rate base and are eligible for cost recovery via a SoBRA. These costs include: EPC costs; development costs including third party development fees, if any; permitting and land acquisition costs; taxes; utility costs to support or complete development; transmission interconnection cost and equipment costs; costs associated with electrical balance of system, structural balance of system, inverters and modules; Allowance for Funds Used During Construction ("AFUDC") at the weighted average cost of capital from Exhibit B of the 2017 Agreement; and other traditionally allowed rate base costs.

Q. How were the projected cost amounts in your exhibit developed?

A. Tampa Electric has worked continuously with the developer to develop the all-in-cost for the Tranche One projects while also maximizing cost-effectiveness. It has been an iterative approach to develop project costs as site due diligence and engineering and design have been conducted. This includes negotiating and executing the module supply agreement, reviewing equipment specifications and pricing, reviewing the scope of work and balance of system costs, and acquiring land and cost estimates to engineer, permit and construct the projects.

Q. Are the projected installed costs shown in your exhibit eligible for cost recovery via a SoBRA pursuant to the 2017 Agreement?

A. Yes. The SoBRA mechanism in the 2017 Agreement includes a strict cost-effectiveness test and a \$1,500 per kW_{ac} installed cost cap to protect customers. The projected installed costs shown in my exhibit are lower than the \$1,500 per kW_{ac} installed cost cap, so the first test for cost recovery under the 2017 Agreement has been met. Witness Rocha demonstrates that the two projects are cost-effective in his direct testimony.

The actual installed costs will be trued up through the SoBRA mechanism once the projects are complete and the work orders have been closed.

Summary

Q. Please summarize your direct testimony.

A. Tampa Electric is developing two single axis tracking solar PV projects for an in-service date of September 1, 2018. The Payne Creek Solar site is located in Polk County, Florida, and the Balm Solar site is located in Hillsborough County, Florida. Each site is approximately 500 acres and will support a 70.3 to 74.4 MW project. The anticipated cost for each project will range from \$1,324 /kW_{ac} to \$1,480 /kW_{ac}.

Q. Does this conclude your prepared direct testimony?

A. Yes, it does.

BY MR. WAHLEN:

Q Mr. Ward, did you also prepare and cause to be filed with your direct testimony an exhibit marked MDW-1 consisting of six documents that has been identified on the comprehensive exhibit list as Exhibit No. 2?

A I did.

MR. WAHLEN: And, Mr. Chairman, I believe that has been entered into the record.

CHAIRMAN GRAHAM: Duly noted.

MR. WAHLEN: Thank you.

BY MR. WAHLEN:

Q Mr. Ward, would you please summarize your prepared direct testimony?

A I will.

Good afternoon, Commissioners. My name is Mark D. Ward. The last time I was present before this commission, I served as a member of a panel of witnesses during the November 6th, 2017, hearing on Tampa Electric's settlement and stipulation, which ended in a solar base rate adjustment, or SoBRA.

The direct testimony I am prepared -- I prepared, describes the two Tranche One projects which cost recoveries requested via Tampa Electric's first SoBRA. It also addresses Tampa Electric's process and plans to develop and construct 600 megawatts of cost-effective photovoltaic SoBRA in its service area. The projects in-service dates will be staged in four phases, or tranches, beginning September 1, 2018, and ending January 1, 2021.

My direct testimony provided a description of the projects in the first phase, or tranche. Payne Creek solar and Balm Solar. Together the two projects will produce almost 145 megawatts, and are scheduled to be in service by September 1, 2018.

The Payne Creek solar project is being constructed on approximately 500 acres of reclaimed phosphate mine site in Polk County, and will produce more than 70 megawatts. Balm Solar is being constructed on 540 acres of agricultural land in Hillsborough County, and will produce more than 74 megawatts. Both projects will deploy single axis tracking technology and first solar modules.

My direct testimony describes Tampa Electric's process in selecting full service developers for its projects and ensuring the cost of the projects are competitive.

The First Solar was selected to develop, engineer and construct Payne Creek solar and Balm Solar projects. First Solar, a U.S. owned company, is not only a world-class manufacturing of thin film modules, but has developed and constructed more than five gigawatts of successful PV solar projects.

The project install costs for the Tranche One projects, Payne Creek and Balm, are $1,324 per kW, and $1,480 per kW respectively. Both projects costs are less than the $1,500 for kW cap and comply with the terms of the settlement agreement.

Thank you.

MR. WAHLEN: Mr. Ward is available for cross-examination.

CHAIRMAN GRAHAM: Okay. Mr. Rehwinkel, you want to go first or second? You have the man.

MR. REHWINKEL: Thank you, Mr. Chairman.

EXAMINATION

BY MR. REHWINKEL:

Q And good afternoon, Mr. Ward.

A Good afternoon, Mr. Rehwinkel.

Q I was going to be nice, but the Chairman admonished no friendly cross, so I will try to make this as hostile as possible, if that will put you at ease.

A I am glad to be here.

MR. REHWINKEL: In all seriousness, Mr. Chairman, I have passed out a couple of exhibits that, at your pleasure, we can just mark here.

CHAIRMAN GRAHAM: Let's mark them now.

MR. REHWINKEL: Okay. So would 13 be the first?
MR. TRIERWEILER: That's correct.
MR. REHWINKEL: And the first one would be FPL's Response to Staff's Third Set of Interrogatories --
CHAIRMAN GRAHAM: Okay.
MR. REHWINKEL: -- No. 24.
(Whereupon, Exhibit No. 13 was marked for identification.)
CHAIRMAN GRAHAM: Okay.
MR. REHWINKEL: And 14 would be NREL Q1 2016 Benchmark Report Excerpt.
CHAIRMAN GRAHAM: All right.
(Whereupon, Exhibit No. 14 was marked for identification.)
MR. REHWINKEL: I will put those aside. We will get to these later.
CHAIRMAN GRAHAM: Mr. Ward, if I can get you to mark those two. Did you do that?
MR. REHWINKEL: Just put on -- for the FPL 13, just write 13 up there. There you go.
THE WITNESS: And the other one is 14?
MR. REHWINKEL: And the other one is 14, yes.
BY MR. REHWINKEL:

Q Mr. Ward, you are the company witness who was responsible for testifying to the compliance with the technical provisions related to SoBRA in the 2017 agreement, is that correct?

A That's correct.

Q Okay. And you are also the witness responsible for testifying to any questions about the discovery responses that are identified next to your name in the staff exhibit, is that right?

A That's correct.

Q Okay. Mr. Ward, do you have a copy of the 2017 agreement with you?

A The stipulation?

Q Yes.

A Yes, I do.

MR. REHWINKEL: Mr. Chairman, I had talked to counsel for TECO about a copy of the agreement. The 2017 agreement is contained in a Commission order, and I think we are going to have questions about them. He had -- Mr. Wahlen had indicated they had already made copies, so I didn't bring another set --

CHAIRMAN GRAHAM: Okay.

MR. REHWINKEL: -- and I would ask if we could distribute those at this time.

And, Mr. Chairman, the process has been both ways, where Commission orders are given an exhibit number, and sometimes they are not. It would be my suggestion, since this is going to be discussed a good bit, that we give it a number, if there would be no objection.

CHAIRMAN GRAHAM: I have no problem with that. We will give it No. 15.

MR. REHWINKEL: Thank you.

(Whereupon, Exhibit No. 15 was marked for identification.)

MR. REHWINKEL: And the sort title would be 2017 agreement.

CHAIRMAN GRAHAM: All right.

BY MR. REHWINKEL:

Q Mr. Ward, two of the witnesses for Tampa Electric, Mr. Ashburn and Mr. Rocha, filed revisions to their testimony, but you did not, correct?

A Except for the one correction.

Q Yes. But you didn't revise yours in February, and the reason for that is is that the tax reform that was passed eight days after you filed your original testimony did not have any impact on your numbers, is that right?

A That's correct.

Q Now, you made a revision in your introduction to change the number of 150 -- 150 to 100, what was it, approximately 145?

A That's correct.

Q And the question I have for you is is there a possibility that the company would build more than 144.7 or 145 megawatts for these two projects?

A No.

Q Okay. In the agreement, there is a provision that you may be familiar with that allows the company to carry over in union used capacity below the targeted amounts for 2018, that would be 150?

A Correct.

Q Is there -- would the company be planning to carry over the five megawatts that are unused in 2018 for consideration in another year?

A Yes.

Q Okay. Now, when we see in your testimony, and testimony of others about 144.7 or 145 megawatts of solar, is that based on some sort of technical ability the facilities that you are installing to generate that much solar on a maximum basis? Is it a nameplate, or is it some sort of average? Can you give me a little bit of background on that?

A It would be like a nameplate. It's a design.

It's part our contract with the developer for each of those projects, so that's a maximum output.

Q Okay. So would you expect, on an average basis throughout the year, to achieve that, or would it be based on conditions and --

A It's based on weather. You need a really good day to hit those numbers, but that would be the maximum output of the projects.

Q Okay. And at this point, there are no plans between now and the actual installation of the project to increase the two projects from 144.7 to another number, is that correct?

A That's correct. These are turnkey contracts, and the output is agreed to in the contract.

Q Okay. Earlier, I asked you about your responsibility for interrogatory responses that are identified in the staff exhibit. And am I correct that interrogatories, the responses of the company to staff interrogatories four and five are your responsibility?

A That's correct.

Q Okay. And do you have those -- I want to ask you about the answers to Interrogatory 4C and Interrogatory 5C. Do you have those with you?

A Yes.

MR. REHWINKEL: Before I continue with

Mr. Ward, Mr. Chairman, I have -- I am assuming that the staff -- that the Commission has copies of the documents, at least the nonconfidential documents that are identified in the staff exhibit.

CHAIRMAN GRAHAM: Yes.

MR. REHWINKEL: Okay.

BY MR. REHWINKEL:

Q So the documents I am going to ask you about are contained in Exhibit 7. And I would ask you to turn to the answers to 4C and 5C. Do you have those?

A I do.

Q Okay. All right. Now, if I could get you to look first at 5C. I think the staff asked how many acres are in the Balm property -- how many acres in the Balm property would be suitable for future development as a solar installation, or for other utility purposes. Do you see that?

A Yes, I do.

Q And could you read the answer to that one?

A Approximately 111 acres may be available for future cost-effective battery storage to be integrated with the solar project. There are no plans to expand the project beyond 74.4 megawatts AC.

Q Okay. Now, the reference to expansion for battery storage is not -- there are no costs in your

proposal that's before the Commission for cost recovery for SoBRA under the battery storage, is that right?

A That's correct.

Q Okay. And if I could get to you look -- turn now to Interrogatory 4, and this is a question about the Payne Creek project. The same question is asked in 4C that I read aloud, except for Payne Creek, and would you read the answer?

A Yes. Approximately 80 acres may be available for a future cost-effective battery storage project to be integrated with the solar project.

Q Okay. Thank you.

And again, with respect to battery storage, there is no battery storage costs included in the project submitted for cost recovery in this docket related to battery storage, is that right?

A No, sir.

Q My penultimate question about this is, is in 5C there is an affirmative statement there are no plans to expand the project beyond 74.4 megawatts AC, but no similar statement in 4C related to Payne Creek. Do you see that?

A Yes, I do.

Q Okay. Is that an oversight, or is it --

A Yes, it is.

Q Okay. So the statement that we see in 5C about no plans to expand the project if it was -- what's the Payne Creek project?

A It's roughly 70.3 megawatts.

Q And it's going to stay 70.3?

A Yes, sir.

Q Okay. In your testimony, on page eight, lines four through seven, you make the statement within that testimony that says: The company expects both projects to be complete and in service on or before September 1, 2018. Do you see that?

A Yes, sir.

Q Okay. You would agree with me that the agreement in paragraph 10, page 10, the -- and paragraph 11, say that the company can't recover for the 2018 tranche before September 1, 2018; is that right?

A That's correct.

Q Okay. So just for the record, if you put the -- this project in service before September 1, 2018, customers would not be paying for the cost of that project prior to September 1; is that right?

A That's correct. They would receive the fuel benefits, though.

Q They would, though, yes.

A Yes.

Q Is -- and just so I understand, is your statement about on or before, is that designed to convey that it's going to be right in that neighborhood? It might go on a day or two earlier, or is there a possibility it could be a lot earlier than September 1?

A We are going to try to land it on a head of a pin.

Q Okay.

A Yes. Yes.

Q And that way you would recover exactly the costs that you have in the project?

A Yes, sir.

Q Okay. All right.

All right. In your testimony on pages eight through 12, you describe the selection process that led the company to select First Solar as your vendor for this project; is that right?

A That's right.

Q Okay.

A Yes.

Q And Mr. Ward, my reading of the timeline of events that you lay out would lead me to believe that the company had already selected and acquired the land for the projects when the proposals from developers were solicited and vetted by the company, but I am not sure

that that's the case; and I would ask if you can clarify whether I am correct in the sequence, or testify here today, whether any of the pieces of property at issue were under consideration as part of projects that were already under development.

Do you understand my question?

A Could you repeat the last part there?

Q Okay. So I am asking if you can clarify whether I am correct in my sequence that you already had the land and then you went to the developers, or whether any of the pieces of property, either Baum Road or Payne Creek, were being considered by those developers before you talked to them?

A Okay. So do I need to answer yes or no?

Q No. You can say whatever you want on this one.

A Okay. The way this process was unfolding is -- so we were out actively looking for land in our service area. And when we identified land that we thought was going to be a viable candidate for projects, we would enter into an option with the landowner at a prenegotiated price, and would give us usually 90 to 180 days of due diligence. And so at the time that we were selecting our developers, we had several pieces of land under option, including Payne Creek and Balm.

Q Okay. So when I look at the staff discovery and 4C and 5C, so if I could get you to look back at those.

A Okay.

Q You would agree with me -- well, first of all, I think it's in another part of the discovery.

The land that was acquired for Payne Creek, the cost of that land was -- well, let's see, if you could look at nine, Interrogatory 9. I am sorry, I had it wrong in my notes. Can you look to paragraph -- to Interrogatory Response 9 --

A Yes, sir.

Q -- and this is the redacted version of it.

A Yes, sir.

Q It shows that the land cost for Payne Creek was $1,290,816. Do you see that?

A That's correct.

Q And then in Interrogatory 9, for Balm, the land cost for Baum Road is $18,624,873. Do you see that?

A That's correct.

Q Okay. Now, the per acre cost of the Payne Creek land that was 84 acres, that comes out to roughly $2,700 an acre; is that right?

A Pretty close.

Q Okay. And then the Baum Road land was 541 acres, is that right?

A Close.

Q And that would come out to the neighborhood of $34,500 an acre --

A Correct.

Q -- is that right? Okay.

A Yes.

Q All right. Can you tell me if -- well, first of all, can you generally explain the difference between why those two pieces of property were so much different in cost?

A Yes. First, let me state that these two projects really are bookends on the cost for land, so we had the cheapest land that we were able to find, the lowest cost, which would be Payne Creek, and the highest cost which is Baum.

Payne Creek is a reclaimed mine site that was reclaimed by Mosaic, and it has some challenges as far as constructability, but it was -- due to the cost of the land, we were able to make this a viable site for solar.

Balm, on the other hand, is in an area that's right on the edge of growth in Hillsborough County. And let me just take a step back. We have a very compact service area. It's highly developed. There are -- in a lot of parts in Florida, there are a lot of wetlands. It's very hard to find what we would call upland, or dry land.

Balm is an agriculture sight for berries, strawberries and watermelons, and very profitable, very near a highway developed area, and so the -- the cost for Balm was -- was much higher than Payne Creek.

Q Okay. Can you state for the Commission, for the benefit of the record, whether the purchase of the Baum Road land was an arm's-length transaction?

A Yes, it was.

Q Okay. And there -- by that, you mean the seller of the property was in no way affiliated with Tampa Electric, or anyone who works for Tampa Electric, or related to anyone who works for Tampa Electric?

A That is correct.

Q Okay. So I appreciate your description.

Is there any -- are there any other characteristics of the Balm property that led you to purchase it versus another property with respect to, say, location to your facilities?

A Operationally, it was a good site for our system. We have a transmission line that runs directly over the site, so it did minimize our interconnect costs. Those are also two drivers. And it was a very constructable site since it was flat and dry.

Q Okay. So I noticed in the interrogatory response that I asked you for the dollar figures. The interconnection costs for Balm was 2.5 million -- the projected interconnection costs, and the projected interconnection costs for Payne Creek is 4.4 million?

A That's correct.

Q Is that a indication of relative distance between the output of the solar array and interconnection to the transmission system?

A You are correct.

Q Now, I know Mr. Rocha is the -- is testifying about the revenue requirements, but you are familiar with the per kWac costs of both projects, right?

A Yes.

Q Okay. And the Balm Creek -- the Baum Road project came in at $1,480 on an estimated basis, or $20 under the cap; is that right?

A That's correct.

Q Okay. Now, you are also familiar with the provision in the agreement on 6(e). It's on page 13 of the agreement. Where it says: The installed cost cap is not a safe harbor or billed to number for the company. The company will use reasonable efforts to

design and build solar projects at installed costs below the cap.

Do you see that?

A Yes, sir.

Q Okay. And do you understand -- do you have an understanding of what that's intended to --

A I do.

Q What is your understanding of that?

A It's my understanding that I need to build the lowest cost project possible.

Q Okay.

A And if you talk to my developer, I wish he was here to testify, he could tell you that we had discussions on this every day.

Q Okay. Mr. Ward, and I am asking this question so I can develop the record and understand what the company did in regard to this.

On first blush, it might look to some that the money that was paid for the -- well, let me -- let me step back and ask this: Would you agree that basically the numbers, given the variance in the output of the two projects, the big driver in the difference in cost is transmission and the land cost is a delta between those two?

A I would agree with that.

Q Okay. And we've already discussed the difference between the transmission cost is a littlest than $2 million?

A That's correct.

Q So the biggest driver would be the land?

A And keep in mind, again, I will tell you that you are looking at our project with the lowest cost land and our project with the highest cost land.

Q Okay. So on the face, it could appear to some observer that the land price was paid up to something just below the cap so that there would be a maximum value paid to the land. Now, I am just asking you to disabuse the Commission and observers of that notion, if you could.

A That's not correct. With Balm, when we originally -- you know, we go through our selection process on land, it's pretty exhaustive, and it's really a balancing act between land, equipment, balance of system and interconnection costs.

And when we decided to purchase the land for Balm first, I was really happy to find 500 acres without a lot of wetlands on it, but our original screening cost was quite a bit lower than the 1,480. As we developed the project, there were some costs that were added to the project that increased it to the $1,480 per kW.

Q Okay. And I know this is not directly at issue here today, but you have made a point that these are bookend costs, lowest and highest. For the Commission's edification, can you give an idea of what's the next most expensive property on a per-acre basis?

A Yeah. It's probably around $30,000 an acre. The average cost per acre for our 10 projects is just above $20,000 an acre.

Q Okay. So obviously there must be a mix of some more reclaimed phosphate land?

A Not at this price that we see Payne Creek, but we do have another project that is reclaimed mine site.

Q Okay. All right. Now, I made some issue recently here in my questions about the fact that you pay just under the cap -- well, that the price of the Baum Road land pushed the cost of the project up to just under the cap, would you agree with that?

A It's $20 less --

Q Yeah.

A -- than the cap, yes.

Q But it is also true that to the extent you move that cost closer to the cap, the shareholders earn less of an incentive --

A That's correct.

Q -- on this? Okay.

So -- and to the extent you pay less for land, the shareholders earn more than incentive?

A If the -- well, I don't -- they have the opportunity. I don't -- I can't say that that's for certain.

Q Okay. All right. Just a -- one more question about Baum Road, then I will move on.

Is it your testimony that there was no other comparable property suitable for this project that would have been significantly less in cost?

A I agree with that statement.

Q Okay. Can you -- do you have your interrogatory -- your response to Interrogatory 10 with you? And I am just going to ask you about the redacted version. If you have a -- if you have the complete version to refer to, that's fine.

A I have got a copy.

Q Okay. Now, I am asking you -- I don't want you to disclose anything in those -- in the yellow that's on your page, okay?

A Yes, sir.

Q All right. So I am going to ask you a general question about, there is developer one, two and three, and this is your response to the staff's question about your testimony on page nine, lines six through 15 of

your testimony, where they are asking you about the short listed developers.

A Okay.

Q And I think you said initially you had four and one dropped out?

A That's correct.

Q So three competed, is that fair?

A Originally 60 competed.

Q But on the short list, it came down to three?

A Well, yes, after one dropped out.

Q Okay. And I assume these are identified as developer one, two and three that First Solar, who became your vendor for all of your solar projects under this agreement, is that right?

A First Solar is a vendor for eight of the 10 projects.

Q Okay. First Solar is one of these three, is that right?

A They are.

Q Okay. Now, can you tell me, of the three, was First Solar the lowest on the projects that -- well, let me step back.

What you have are some pieces of property that were not necessarily the ones that were used, but how would you put an array on these properties, and then you

compare, is that fair?

A That's fair. So there were one, two -- three of the properties are actually projects. They are just under a different name.

Q Okay. So was First Solar the lowest price? How did that shake out?

A So I need to step back here and kind of walk you through the process.

So when we went to the short list of four developers, we had one drop out, originally I split the projects -- or we split the projects, the awards primarily between two developers that manufactured modules, one of them being First Solar.

As momentum picked up on this module import duty that was signed in January, we began talking with First Solar, and felt that we could protect ourselves with their technology because it was exempt from the import duty. So we ended up procuring all of our modules from First Solar.

When that happened, they became the developer of choice, because they are able to install their modules at a lower rate than anybody else.

Q Okay. So if the Commission and its staff were to look at the confidential version of Interrogatory 10, would it be apparent to them what you just said about

the modules and the price of those, would they be reflected in the relative pricing here if they knew which one of these was First Solar?

A Probably not.

Q Okay. Now --

A And let me just explain.

So you have three developers all using, at this point, three different types of modules. And so, you know, when we decided to go with First Solar, we did ask -- we did ask the other developers if they would be willing to use First Solar modules. The other module manufacturer declined, and so he bowed out.

And so then I was left with First Solar and one other developer, and they were able to meet the price for their project -- and they brought the land to us, by the way, that's how they stayed in the game. And they were able to meet a price that we thought was competitive for that site. But First Solar, by far, can install their modules cheaper than other developers.

Q Okay. So the pricing that's reflected in this comparison isn't necessarily what led to the selection of First Solar?

A It was part of the process.

Q Okay. But it's not -- it wouldn't be a true comparison because of what you described about the

certainty of the modules that First Solar was bringing to you?

A That's correct.

Q On page 12, lines three through 19 -- well, actually, three through nine you talk about receiving unsolicited proposals from developers. Do you see that?

A One second. Oh, you're on my testimony.

Q I'm sorry.

A I was looking in the agreement.

Q I am sorry. So page 12, lines three through 19.

A Okay.

Q All right. You state there that Tampa Electric occasionally receives unsolicited proposals from developers, and then you state, the company's solar projects compare favorably to these proposals. Do you see that?

A Yes, sir.

Q Okay. Now, when you state the company's solar projects, are you specifically talking about Payne Creek and Baum Road?

A Yes, I am talking about our SoBRA projects.

Q Okay. And when you say these proposals, does that mean you got concrete proposals for specific sites?

A I wouldn't call any proposal concrete, but I did get proposals for specific sites.

Q All right. And when you say compare favorably, what does that mean specifically on a -- on a kind of a tangible basis?

A Well, they were favorably -- compared favorably as far as cost goes, but as far on a dollar per megawatt basis, they were not favorable.

Q Okay. So what you're saying is that the projects, at least the two that are before the Commission today, were, from a customer bill perspective, lower than any proposals you received -- of these unsolicited proposals; is that right?

A That's correct. And let me explain.

The proposals that we got, we received were for projects that were on land outside our service area, and so they would be subject to wheeling costs, and that really eliminated them from consideration.

Q Okay. Let me ask you a question about that. If you could look on page 11 of the agreement.

A Okay. The agreement or my testimony?

Q Of the agreement. And I want to take you to, 0I believe it's the first full sentence that starts: A SoBRA tranche. Do you see that sentence?

A A SoBRA tranche, yes.

Q Okay. So it says: A SoBRA tranche may

consist of a single project, or may include multiple individual solar projects which may be located throughout the company's retail service territory.

My question to you is, do you read that as requiring that the -- your projects that are eligible for SoBRA recovery must be located in the service territory?

A That's the way I read it, yes.

Q Okay. So -- and to your knowledge, all of your projects were selected based on their location within Tampa Electric's defined service territory?

A They were based on a lot of reasons. That was one of them.

Q Okay. But that certainly is one that applies to all the selected projects?

A It does.

Q Okay. So even if -- so is it also then, in these unsolicited proposals, some of them were outside of your territory?

A I believe all of them were. I believe all of them were during the selection process.

Q Okay. So if you got an unsolicited proposal that just blew your socks off, it was really good, and even with wheeling, it was better than anything you would do, you would either have to let it go, or come to

the Commission and the signatories and get a waiver? Without asking for a legal opinion.

A Under the stipulation, we have the right to build 600 megawatts of SoBRA, and that's what we've been executing.

Q Okay. But I am saying, if you had a good proposal that was out of territory, you really wouldn't be able to take advantage of it?

A Mainly because of wheeling costs.

Q Okay. And this language in the agreement?

A That is correct.

Q Okay. All right. All right. Let's go to page 14 of your testimony, and I want to direct you to line 13. And on line 13, you use a term "all-in-cost," do you see that?

A Yes, sir.

Q All right. Tell me what that means to you with -- in the way you used it in this testimony.

A So the all-in-cost is really, to me, self-evident. It's the equipment, modules, the balance of system, including electrical and structural. It's development cost. It's the transmission interconnect. It's the project substation. It's the land, including the acquisition costs. It's the owners costs, that is all the all-in-costs.

Q AFUDC included in that?

A Thank you. AFUDC as well.

Q Okay. And when you use all-in-cost in your testimony, is that intended to comport with the general requirements of the agreement that all of the costs that are required for bringing these solar projects into service are what is measured -- or what are measured against the $1,500 cap?

A Yes.

Q Okay.

A In fact, I think the stipulation spells out those costs.

Q Okay. So let's look at page 12 of the stipulation, and in 6(d), is what you just testified about the items that are listed in what looks like the last sentence that starts on that page, about seven or eight lines up. It says: The types of solar -- types of costs. Do you see that sentence?

A Yes, sir. That's correct. I think I omitted EPC costs, and obviously that's included as well.

Q Okay. All right. So let's just go -- let's just review these if we can.

There is a reference -- and I just want to go -- let's see, so EPC costs, that's -- is that what First Solar does?

A First Solar is really what I would call a full service developer. They have been involved in developing the project, designing the project and overseeing the engineering procurement construction for the project as well.

Q So are EPC costs included in the price they -- that you -- in what you pay them?

A Yes, sir.

Q All right. So are they subcontracting with a contractor?

A On some of the work, they subcontract. On some of it, they self perform.

Q Okay. In any event, EPC costs are included in what you pay them completely?

A Yes, sir.

Q All right. And then development costs, including third-party development fees, is that what you pay First Solar?

A For some of the development, we pay First Solar. We also have consultants that we use for assistance in the permitting, we pay them. We pay attorneys.

Q Okay. And so all of those costs would be -- that you just listed, are considered development costs, including third-party development fees?

A Yes, sir.
Q And then permitting fees and costs, do you have those kind of costs in this project?
A Yes, sir.
Q And then we talked about the land cost. So when it says actual land cost and land acquisition cost, all of those $18 million and $1.29 million that we discussed in that interrogatory response includes those two elements of land?
A Actually, the acquisition costs are broken out in that exhibit right below the land costs.
Q Okay.
A I think it's 4 and 5.
Q No. That would be nine.
A That's right. You are right. The land acquisition costs for Payne Creek was $117,540; and for Balm Solar, $95,255.
Q Okay. Well, let's keep this document out as we go through this -- these items on this list.
So if we could step back, I asked you about EPC costs. On these two pages for Payne Creek and Balm, where would the EPC costs be on these line items?
A Well, so EPC would include engineering. It would include modules, inverters, substation, trackers, site prep roadwork, installation. It becomes kind of a

mixed bag between balance of system and EPC costs.

Q Okay. So it's spread throughout?

A Right.

Q All right. So we talked about land cost and land acquisition cost.

Taxes, is that primarily property taxes?

A Primarily, because I think most of the equipment costs are not under any kind of sales tax, so property taxes would be future operations cost.

Q Okay. So there are no property taxes in the 12 -- the 1,324 and the 1,480?

A I don't believe so. It would more than likely be in our O&M projection.

Q Okay. All right. So taxes are going to be fairly small in this?

A Fairly small.

Q Okay. But there are some taxes in the -- in the --

A They are embedded.

Q Okay. And then utility costs to support or complete development. Is that considered owners costs?

A No, the utility costs are probably somewhere in the -- so the owners costs are our costs.

Q Yeah.

A Everything else -- and the land costs are beared by Tampa Electric. They -- the turnkey project costs are primarily the equipment, the trackers, SCADA, balance of plant, most of the permitting, engineering, installation, site prep, fencing, transmission costs is a Tampa Electric cost.

Q So what I am tying to understand is utility cost is --

A Oh, so the utility costs, those -- they are somewhere in these costs. That was the responsibility of First Solar to provide any costs on-site power --

Q Okay.

A -- for instance, or water.

We made a commitment early on that we wouldn't use water for the operation of the projects, and so we are requiring the developer to bring water on the site.

Q Okay. So they will bring a tanker truck in?

A Yes, sir.

Q All right. And -- now, when I asked you about owners costs, owners costs that are required because of this project are included in the 1,324 or the 1,480; is that right?

A Yes, sir.

Q Okay. And costs associated with the electrical balance of system, those are -- we see balance of plant?

A Yes.
Q All right. And these are the pieces of equipment that actually --
A Cabling, combiner boxes -- it's primarily cabling and combiner boxes.
Q Okay. And then the structural balance of system, are those costs in here?
A They are. Some of those would be in balance of plant, and also you have some structural costs with the trackers.
Q Okay. And, of course, inverters are included?
A Inverters and air pad mounted transformers are included.
Q Say that again. What was that?
A So there is transformers with the inverters, they are included together.
Q Okay. And then modules, we talked about that --
A Right.
Q -- those are actually the solar --
A First Solar.
Q Okay. AFUDC, we talked about that. There is a AFUDC component?
A Yes, sir.
Q And then, I know in your testimony, you talk,

on lines six and seven of page 14, other traditionally allowed rate base costs which are taken from the agreement. Are there any of those that we haven't talked about that's sort of a catch-all? I am in your testimony on page 14, lines six and seven.

A Could you ask the question again, please?

Q Yeah. My question is, are there any costs that we haven't talked about that would be sort of in that catch all of other?

A I don't believe so.

Q Okay. So the itemization on staff's Interrogatory 9 are pretty much all of the elements that this is the all-in-cost, is that right?

A That's correct. Yes.

Q Okay. All right. I have passed out these exhibits, 13 and 14 that I would like to just ask you about before we leave this subject. And 13 is an interrogatory response that Florida Power & Light provided to the Commission staff in a docket last year. Have you seen this before?

A I haven't.

Q Did you say you have?

A I have not.

Q Oh, you have not, okay.

Well, when you looked at what Tampa Electric

was going to build, and how you were going to decide whether to meet the cap or not, did you look to see what other utilities had done under similar SoBRA arrangements?

A We've tracked that, but we were -- we were moving towards developing our strategy and executing it before a lot of the SoBRA information was available.

Q Okay. Have you compared what Tampa Electric is including in the all-in-costs compared to what Florida Power & Light submits as all-in-costs in their SoBRAs?

A I have.

Q And can you tell me, are there things that you have included that they haven't, or that they've included and you haven't? And when I say things, I mean cost components.

A I don't believe so. They use a fixed mounting structure so -- and we use single axis tracking. So there is a difference there, but I believe we are both including the same costs.

Q Okay. So I guess another way to ask that is you haven't gleaned anything that they've included that you haven't?

A No, sir.

Q And vice-versa, there is nothing that you have

included that doesn't appear to be something they've included? I am not trying to get you to tattle on them, I am just tying to understand.
A I don't believe so.
Q Okay. You mentioned single axis tracking. That's the technology you are using as required in the agreement, right?
A That's correct.
Q And single axis tracking means that solar array, to some degree, moves with the transit of the sun?
A It follows the sun throughout the day.
Q Okay. And fixed tilt does not?
A It does not.
Q Okay. If I could get you to look at page 12 of the agreement.
A The agreement or the --
Q The agreement.
A Okay.
Q And just above that area where we were going through all the costs that were in the agreement, there is the sentence that says: Each project qualifying for SoBRA treatment must consist of either single axis tracking or other solar electric generating equipment or tracking technology that yields greater efficiency, or

higher capacity value, or both, for the benefit of customers all within the cost cap stated in this paragraph six.

Do you see that?

A Yes, sir.

Q Now, at the time you developed the 2018 tranche subsequent to the signing of this agreement, was the single axis tracking technology the best available technology, as described in that sentence, available to the company?

A Yes. And primarily, you could also say that it was the best technology for First Solar modules as well.

Q Okay. And I know we are not here about the next 450 megawatts, but is there a possibility that dual axis tracking would be used? Is there something that's better?

A I will answer that no, and then I will explain.

Q Okay.

A I don't think -- or at least as of where we sit today, dual axis tracking is just not cost-effective and not economical.

Q Can you just tell us why?

A It's expensive. It's more expensive than single axis tracking, and it's not as well proven.

Q Okay. So it's unlikely that you will be looking at that in the horizon?

A We look at a lot of different things throughout the year just to check ourselves. So the answer would be, yes, I will be looking at other technologies as we go forward.

Q Okay. All right. So I just have a few more questions about the all-in-costs. I think that your testimony is that everything that is included in the 1,324 and the 1,480 numbers are what it costs to put these solar arrays and systems into service; is that fair?

A That is -- yes.

Q Okay. So I am going to ask you some questions that are kind of long. If you don't understand them, I will break them up for you, but I just want to ask you questions that would sort of test that.

So is it your testimony that there will be no costs included in Tampa Electric jurisdictional retail cost of service after September 1, 2018, that is either not included in the 1,324 and 1,480 numbers, either projected or actual, and would not be included in your jurisdictional retail cost of service but for the two solar projects in the first tranche provided for in the

2017 agreement?

A You are going to have to break that up.

Q Okay. So what I am trying to understand, when you -- when you find -- these are projected costs, and you are going to build the project and going to --

A There will be a true-up.

Q -- tally everything, and there will be a true-up and say, this is what we actually spent?

A That's correct.

Q And if it's a little more or a little less, there will be an adjustment down the road, right?

A Correct.

Q Okay. And after that is done, there will -- those costs will be booked -- I know you are not the accountant, but they will be booked on the company's books, right?

A Yes, sir.

Q And then the projects will be in service. My question is, would there then be any other costs that wouldn't be required other -- except for these projects that would also be included in the cost of service of the company that are not in the 1,324 or 1,480, assuming those are the final numbers?

A Those are the capital costs, but we also will include in our cost-effectiveness the O&M costs --

Q Okay.

A -- projected O&M costs of the projects.

Q But O&M costs wouldn't be in the 1,480 --

A That's correct.

Q -- or 1324 in any event?

A That's correct.

Q So my question was to you about just capital costs.

A That's correct. I agree.

Q All right. And if that was to happen, it would not be intentional on the company's part, is that right?

A That is correct.

Q Okay. Are you familiar with how the incentives work?

A I am familiar.

Q Okay. I know Mr. Rocha is more the test -- the witness on that, but I am going to ask you this question along that line, and if you are not able to answer it, I understand.

But would you agree that if you ultimately are going to get an incentive based on the 75/25 split that's in the agreement, your actual costs, your actual capital costs have to be lower than $500 --

A That's correct.

Q -- for kWac, right?

A That's correct.

Q All right. So the integrity of that incentive that your shareholders would earn if they bring -- if you bring the projects in lower, is going to be based on the veracity, or the accuracy, let's say, of the final cost numbers; would you agree with that?

A That's correct.

Q Okay. So if there are costs that are attributable -- capital costs that are attributable to the project but not included in the 1,324 and the 1,480, hypothetically, and your incentive is based on an actual number that's not accurate, the incentive might not be accurately calculated, would you agree with that?

A With what you described, I agree with that.

Q And that's a hypothetical.

A It is a hypothetical.

Q Okay.

MR. REHWINKEL: Mr. Chairman, I believe those are all the witnesses I have -- all the questions I have for this witness.

Thank you, Mr. Ward.

CHAIRMAN GRAHAM: Don't tease me like that.

THE WITNESS: Thank you.

CHAIRMAN GRAHAM: Mr. Moyle.

MR. MOYLE: I am happy to plow through. I don't know if the witness is in need of a break, but whatever your pleasure is.

CHAIRMAN GRAHAM: Mr. Ward, are you good?

THE WITNESS: I am good.

CHAIRMAN GRAHAM: Plow through.

MR. MOYLE: Okay.

EXAMINATION

BY MR. MOYLE:

Q Good afternoon.

A Good afternoon.

Q So I want to go through some just maybe clarifying questions that Mr. Rehwinkel asked you, and then I have some other questions.

I am not sure I completely followed you with respect to the conversation you had with Mr. Rehwinkel about whether First Solar was the best deal for ratepayers or not. Could you just answer plainly, was First Solar the best deal based on the 60 that came in to you, and then you culled them down --

A First Solar was the best developer for these projects.

Q Great. And that is from a cost perspective, just --

A That's correct.

Q Okay. And the process you went through is a request for information, is that right?

A It began as a request for information to look at qualifications of potential candidates. And then once we selected our short list of candidates, we went through a pricing exercise.

Q Okay. So you went from 60 to four?

A We sent the RFI out to 60 entities that we had talked with along the way, 30 responded.

Q Okay.

A From there, we selected four -- short listed to four.

Q And you said that the delta in price was five to seven percent amongst the --

A That's correct. Yes.

Q And you used to be a developer, independent power developer, right, Mesa did wind and --

A Yes, sir.

Q -- renewable energy?

Did you guys have -- when you did projects, were you having -- did you have any projects when you had to wheel power?

A I don't recall -- I don't recall that we had to wheel power. We did most of our projects in Texas, which really has an open structure there. And we did projects in Canada, where there weren't any wheeling costs either.

Q Okay. You, as -- you are director of renewable energy, right, for TECO?

A That's correct.

Q And you keep up with what other Florida utilities are doing, vis-a-vis renewable energy?

A I try.

Q Do you have any familiarity with the wind project of Gulf Power, where they are bringing wind in from Oklahoma?

A I am vaguely familiar with that.

Q Do you think there is any scenario where wheeled renewable energy could be competitive with respect to projects that you are looking at doing?

A As a possibility, when you say any, there is a possibility.

Q So the wheeling costs aren't necessarily a, you know, a fatal flaw necessarily?

A In the case of the proposals that we received, they were.

Q This is 150 megawatts of 600, right?

A 145 megawatts of 600.

Q Okay. And your testimony, I think, said that you will be at six percent of the generation portfolio

mix. I assume that's at the end of the SoBRA initiative, is that right?

A That's correct. It's six to seven percent.

Q Six to seven percent.

And then what does that get added on to as today, as you sit here, with respect to your renewable energy portfolio?

A Our renewable energy portfolio right now really is the Big Bend Solar project, which is roughly 20 megawatts, and the TIA project, which is two megawatts, and the Legoland project, which is roughly two megawatts, so it's a fairly insignificant amount of our generation.

Q All right. But you also get other types of renewable energy in your system, right?

A I don't think so.

Q You don't have any purchase power agreements for biomass?

A I don't believe any more we do.

Q Mr. Rehwinkel asked you some questions about the type of -- you call them modules, and those are the solar panels, right?

A That's correct.

Q Okay. And just briefly, tell the Commission the difference -- and those who may be listening and

others -- the difference between what you are doing with respect to the tracking equipment and fixed.

A I think we -- Mr. Rehwinkel actually described it. The tracking system picks -- essentially puts the module in a position to capture the sun as it rises, and then it moves and follows the sun throughout the day until it sets.

Q And the fixed is just that --

A Stays right in place.

Q So it becomes less efficient as the sun, you know, moves east to west?

A Right.

Q Right. And have you done any analysis or studies as to which one represents the better value for your company, or for customers?

A We had some analysis that we did early on that showed, especially with the First Solar modules that, and the fact that we are land constrained on many of our projects. In other words, it's very difficult for us to find enough land to do a fixed project versus a tracking system, which is a more compact site. When you put all of that together, the more economical projects were the tracking projects.

Q Yeah. But land cost is something you have to consider in that calculation?

A We do consider it.
Q Okay. So --
A We con-- okay.
Q Do you know what percentage efficiency you gain from a tracking system as compared to a fixed system?
A Yeah. It's roughly -- and it depends on -- for where we are in Tampa, it's 20 to 25 percent.
Q The tracking gets you 20 or 25 percent --
A More energy.
Q -- because you follow the sun?
A More energy.
Q All right. I seem to have -- recall others saying that, with respect to a dollar and cents decision, that fixed would be a better deal, and to get to the same megawatt number, you could just buy more land. I guess that would be true if the land was really inexpensive.
A That's correct, and available.
Q Okay. Did y'all consider that at the reclaimed property, or no?
A We bought every single acre of reclaimed property there for Payne Creek.
Q Yeah. Yeah.
A And amazingly enough, they found wetlands on

it, so we avoided that.

Q Yeah. The agreement -- you were asked by Mr. Rehwinkel whether the agreement requires that you used tracking, and I think you said yes. Do you recall that?

A That's correct.

Q Do you understand that to be the case that the agreement -- the settlement agreement requires you to use tracking --

A Yes.

Q -- systems?

A Yes.

Q And then show me where you get that, if you would. I think it's on page 12, paragraph D.

A Do you want me to read it to you?

Q Sure.

A Each project qualifying for SoBRA treatment must consist of either single axis tracking or other solar electric generating equipment or tracking technology that yields greater efficiency, or higher capacity value, or both, for the benefit of the customers all within the cost caps stated in this paragraph six.

Q So I read that -- I read the phrase, or other solar generating equipment to be sort of a catch-all that would include fixed.

A Okay.

Q Do you think that is a reasonable reading of that, or no?

A It's a reasonable reading; but for our projects, and for our service area, the best economics were borne out in tracking systems.

Q Okay. I just wanted to clarify, you did the economic analysis, and you didn't say, we don't have a choice. You just ran the numbers, and said we think tracking is the best?

A Correct.

Q Okay. And you say, in your testimony, that you monitor the solar cost of other projects in Florida, is that right?

A We do, and we follow some publications as well.

Q Okay. And that includes municipal solar projects, and other IOU projects, and third parties?

A I haven't seen a lot of cost information on municipal projects.

Q They are all public records, right?

A I just haven't seen them.

Q Yeah. So who is doing the least expensive solar projects in Florida today as we sit here?

A On a dollar per kW basis?

Q Right.

A I think we are pretty close.

Q The business arrangement you have with First Solar, they have all of the solar modules for the remaining build-out in the SoBRA agreement, is that right?

A It's a contract, and that's correct.

Q Right. So that's 600 -- you are good on that 600 megawatts of solar?

A Yes, sir. Yes, sir.

Q And then you say that you are not subject to tariffs because that -- I guess they make them; is that right? They make them here in the states --

A No.

Q -- or why are you not subject to tariffs?

A The reason it was borne out early on when they were scoping -- when the International Trade Commission was scoping out the analysis for injury to the industry, they exempted First Solar because of their technology. It's not a CRI-SIL Sillicone technology, it's a thin film technology using a different type of material called cadmium tellurite.

Q Were the projects -- were the modules made in the United States, or --

A Some of them are made in the United States.

Some are made in Malaysia and some, in the future, not our modules, but they are opening a plant for their Series 6 modules in Vietnam.

Q And are there other solar companies that similarly have an exemption like First Solar?

A There are. There are some other manufacturers of thin film, but we didn't have the availability of their modules.

Q And you all buy the land, so you have fee simple title of the land -- I guess you had an option, and then once it got permitted, then you closed on the land; is that right?

A Yeah. Before permitting even, though -- even before permitting, we do a lot of due diligence on the site. We do geo -- preliminary geotech. We do some environmental studies. We do some -- you know, we examine the deeds and the titles to the land. Then once we are comfortable with that, then we move forward with the purchase.

Q Okay. And then they are a contractor. They install the solar equipment. They don't have to deed it over you to in terms of a turnover date, it's just you contracted for the solar?

A That's correct. That's correct.

Q Okay. And to be clear, when will TECO

customers start seeing an increase in their bill associated with these 2018 projects?

A I am not sure about the increase in the bill. I think Mr. Ashburn can talk -- speak to that.

The first SoBRA -- the first tranche of SoBRA projects come on-line, or we are planning to have them on-line in September of this year, 2018.

Q Okay. And you are good on that? It's on schedule?

A Today we are on schedule.

Q Any chance of them coming on earlier?

A Potentially, probably more in the future than the first ones.

Q Okay. You are familiar with this agreement, the settlement agreement in the SoBRA provisions?

A Yes, sir.

Q Okay. I noticed that one of your projects is 74.4, right?

A That's correct.

Q Is my assumption correct that you sized it at 74.4 to make sure that you were getting under the requirements for the Power Plant Siting Act in that if you sized it at 74.5, or six, or seven, most people round up in equations like that, and at 75, you might be subject to the Power Plant Siting Act?

A We would be subject if it were in excess of 75 megawatts.

As it was stated in the stipulation, the projects weren't subject to the Power Plant Siting Act as long as we were less than 75 megawatts. This actually helped us manage some costs. It streamlines the process for getting the plants on line. It keeps the costs in check. And I guess the other issue that really goes back to land is that there is very little opportunity to find land to build a project greater than 75 megawatts.

And I will just say last that, on our system, typically 75 megawatts was kind of the limit that we could inject at any one point without added interconnection costs.

Q But when you guys do combined cycle units, you do them this big blocks right?

A And they do upgrades on transmission, too.

Q Yeah. Yeah.

The -- if you go under the Power Plant Siting Act, there is a competitive bidding requirement that's associated with that, correct?

A As I recall, yes.

Q And that's a Commission rule, do you recall that?

A   As best I can recall, yes.

Q   Okay. I think you answered this, but just to be clear, I think Mr. Rehwinkel was trying to get you to concede or admit that every cost component that is associated with the solar projects has been identified and is part of this case; is that true?

A   I concede.

Q   I am sorry? You concede?

A   I concede.

Q   So I guess, to the extent that someone says, oh, gosh, this should have been in, Mr. Rehwinkel will probably be holding up your testimony and saying, you conceded, you don't think there is a likelihood of that scenario happening, do you?

A   We've racked ourselves on trying to include every cost possible for these projects.

Q   Okay. Did you include any costs in these projects that are not identified in the settlement agreement?

A   I don't recall any.

Q   What kind of a warranty do you have on the panels, or the modules?

A   I believe the modules have a 10-year warranty. They also have a guarantee on the degradation rate, which is about, I think, .4 percent a year. Other equipment had different warranties as well. They vary.

Q Okay. And then in terms of the operation, you all are going to operate this, not First Solar, or am I wrong?

A We are still figuring out whether we are going to hire a service provider for that or do self perform.

Q Okay. I thought you told Mr. Rehwinkel O&M costs were not included in these calculations, is that right?

A What I said was O&M costs are included in the cost-effectiveness. It's an annual cost that's not included in the cap -- CAPEX, the $1,500 of kW or less.

Q So if someone said, well, included in the 1,500 -- $1,500 number, how much would that add approximately?

A I have no idea.

Q Who would know that, maybe?

A We would have to go back and calculate even how we get there on that. That's an annual cost.

Q Do you know when you are seeking to have a power plant approved under the Power Plant Siting Act, and you are going through and you are looking at costs, and the bid rule applies, and the Commission is looking at it whether O&M is included in those cost calculations?

A I don't think so, but I -- if it were, it would be included in the cost-effectiveness of the project.

Q Okay. Are either of these projects in the Southern Water Use Cautionary Area, are you familiar with that phrase, SWUCA?

A I am not.

Q Okay. You said that you have an understanding or arrangement that you won't use any water on these projects, that all the water is being brought in in trucks; is that right?

A Water for construction is being brought in by trucks typically to keep the dust down at the site. As far as future operation of the projects, we won't be using any water for the projects. We are going to allow the modules to be cleaned by rainfall.

Q Does that work?

A Yes.

Q There is enough rain in Florida that --

A Yes, it's worked very well at our Big Bend Power -- Big Bend Solar project.

Q I have tried to make that argument with respect to my car, and it doesn't go very far.

A Your car isn't a solar panel.

CHAIRMAN GRAHAM: It's not dirt, it's the paint.

MR. MOYLE: If I could have a minute, I think I am close to being done.

MR. REHWINKEL: If a solar panel looked like a car, Mr. Moyle would have a much easier time.

CHAIRMAN GRAHAM: You knew he was going to squeeze a car analogy in there somewhere.

BY MR. MOYLE:

Q Your 50 megawatts in 2021, how are you looking toward achieving that?

A Our Tranche Four project?

Q Right.

A We look at achieving it by developing and constructing the blended cost for the Tranche One and Tranche Two projects to be under $1,475 per kW.

Q All right. And are you on track for that so far?

A So far.

Q Okay. And the incentive mechanism, we talked a little bit about that. Can you tell the Commission how much under the target amounts you have come in at, and what that has resulted in savings for the customers? I know you did it on, you know, on a basis of a megawatt hour. But if you could just say, this incentive mechanism, you know, we had it at 15, we came in under

that, we did the calculation --

A So for Tranche One projects, our blended cost is roughly $1,404 per kW. So there is about $96 kW that are -- that can be divided up with the incentive.

Q So the bottom line, if you did the math on that, on $96 per kW --

A That's captured in our cost-effectiveness.

Q So what would be the -- can you tell me the total number, like ratepayers saved X number of dollars?

A I don't know that number.

MR. WAHLEN: That might be a better question for Mr. Rocha. He is doing the revenue requirement.

MR. MOYLE: Okay. Thank you.

BY MR. MOYLE:

Q Final line of questioning, I believe, is you -- you are tracking solar development pretty closely, I assume, in your job, right?

A Right now I am tracking my projects pretty closely, but I try to keep an eye on the industry as well.

Q Okay. And is that because right now, you guys -- these are the only projects you got moving forward, the SoBRA projects?

A I have 10 solar projects I am working on right now.

Q Right. And no other projects -- no other solar projects?

A I have -- no. I have 10 SoBRA solar projects I am working on right now --

Q Right.

A -- that are roughly 600 megawatts.

Q Okay, because the question I wanted to ask you was, if you had other solar projects that you were working on, where you saw the pricing trends going with respect to solar. You know, I have been told that solar used to be way up here and it's coming down, and it's coming down, and it's coming down, and it's coming down. And I was curious as to whether you have been exposed to any information that lets you say, yes, I still think it's coming down, or it's going to flatten out, or it's going to go up.

A I think solar -- our solar costs are still on a downward trend; however, there has been a little bit of a bump in the road with the import tax. It's because of that import tax on most projects, it's made them slightly more expensive, less economical.

That's one of the advantages that we gained from procuring our modules early on with First Solar. We were able to keep a fairly competitive price for the modules.

Q And is it your understanding that the tariffs on solar have actually gone into affect, or is that something that's being contemplated and the market may have been reacting to the contemplation of them going into effect?

A What I do know -- I don't know that I can answer that question fully, but what I do know is there is -- modules are more expensive than they were a year ago, and there is less supply right now.

Q Okay. Thank you.

MR. MOYLE: That's all I have.

CHAIRMAN GRAHAM: Staff.

MR. TRIERWEILER: We have no questions.

CHAIRMAN GRAHAM: Commissioners.

Commissioner Brown.

COMMISSIONER BROWN: Just a follow-up question about First Solar. And obviously, it's very advantageous using First Solar with those -- with the modules.

Were you able to get the modules from First Solar for the other tranches?

THE WITNESS: Yes. We've entered into an agreement to purchase all the 600 megawatts with solar -- First Solar.

COMMISSIONER BROWN: Very prudent.
Thank you. That's all.
THE WITNESS: Thank you.
CHAIRMAN GRAHAM: Commissioner Polmann.
COMMISSIONER POLMANN: Thank you, Mr. Chairman.
Good afternoon, sir.
THE WITNESS: Good afternoon.
COMMISSIONER POLMANN: You had mentioned in response to Mr. Rehwinkel's question, your phrase was a turnkey project.
THE WITNESS: Yes, sir.
COMMISSIONER POLMANN: And in that response, you referred to an output being guaranteed in the contract.
THE WITNESS: That's correct.
COMMISSIONER POLMANN: And with respect to that, there was a discussion about a nameplate rating. In the contract, is there a guarantee as to a capacity that that facility produces, or is it -- well, let me just ask that.
THE WITNESS: I am sorry, I didn't hear the last part of your question.
COMMISSIONER POLMANN: Is there, in your contract, a guarantee -- you referred to a

guarantee in the contract. Is that that the facility has the capability to produce a certain --
THE WITNESS: Maximum -- maximum output.
COMMISSIONER POLMANN: Okay. Is there any language as to the actual electricity that will be provided?
THE WITNESS: As far as energy goes?
COMMISSIONER POLMANN: Yes, sir.
THE WITNESS: Yes. There is a capacity factor associated with the contract as well.
COMMISSIONER POLMANN: You responded to Mr. Moyle in a related question about operations, which I take it you have not yet decided as to self perform or contract for that.
THE WITNESS: That's correct.
COMMISSIONER POLMANN: The actual energy provided seems like an operational issue, so can you please clarify if in the contract as to the equipment there is an efficiency --
THE WITNESS: So the --
COMMISSIONER POLMANN: -- that's per unit?
THE WITNESS: Yeah, so the system has to be properly maintained to maximize its performance, the amount of energy that it produces. If the system is maintained to those standards, then there

is the expectation, given weather, what the system will produce on an energy basis.

COMMISSIONER POLMANN: Okay. Now, with regard to that contract, is there clear language on what the utility's recourse is for, you know, a shortfall, or lack of performance against either the nameplate or the efficiency and the opportunity for that contractor to cure? Can you just touch on that for us?

THE WITNESS: Yeah. There is an opportunity for them to cure. And if they are unable, they -- for instance, if they don't reach capacity, they have the opportunity to add more modules, or reimburse the project for the lost capacity.

COMMISSIONER POLMANN: Okay. So in the event that such a thing would occur, a reimbursement, then that would -- that would need to come back in terms of --

THE WITNESS: Correct.

COMMISSIONER POLMANN: -- costs, and so forth. Adding more modules, it wouldn't just be a module cost, it would be other capital that would come in --

THE WITNESS: That's correct.

COMMISSIONER POLMANN: I am not sure how that would be accounted for, but if and when that would occur, that would have to come back here as well?

THE WITNESS: That's correct.

COMMISSIONER POLMANN: All right. Thank you, Mr. Chairman.

CHAIRMAN GRAHAM: Thank you.

Commissioner Fay.

COMMISSIONER FAY: Thank you, Mr. Chairman.

Two quick questions for you, Mr. Ward. The first is, it's sort of a follow-up on Commissioner Brown's question.

Do you have any idea what the potential tariffs would be, I guess, or what those savings are?

THE WITNESS: You know, it's kind of a muddy -- it's a little bit of a muddy water. But in talking with developers and module suppliers that are being affected, the thought -- the feedback that I have gotten is it's 10 to 15 cents per watt. That would -- for us, that would add about $150 to $180 of kW. It would be tough to hit that $1,500 mark if we hadn't gone ahead and procured the modules.

COMMISSIONER FAY: Thank you.

And the other question, and if I could direct

you to the original order on page 11, the
settlement.
THE WITNESS: The settlement.
COMMISSIONER FAY: Thank you.
So Mr. Rehwinkel asked you a question about the projects and the retail service in the retail service area.
THE WITNESS: Yes, sir.
COMMISSIONER FAY: If you could maybe just clarify for me, because I am looking at the language there, and I guess it's the second full sentence that states a tranche -- on page 11 -- that may consist of a single project or may include multiple individual solar projects, which may be located throughout the company's retail territory. Is that a may, or is it --
THE WITNESS: What's the question?
COMMISSIONER FAY: Are proposals that are outside the retail territory, are they still proposals you consider?
THE WITNESS: No.
COMMISSIONER FAY: Okay. And that's based on this language?
THE WITNESS: Yes.
COMMISSIONER FAY: Okay. All right. Thank

you.

THE WITNESS: Thank you.

CHAIRMAN GRAHAM: Commissioner Clark.

COMMISSIONER CLARK: Thank you, Mr. Chairman.

Mr. Ward, just a couple questions regarding your load profile as it relates to solar.

Where does solar actually fit into TECO's load profile? Where will you be using this generation resource as, base, intermediate, peaking?

THE WITNESS: Well, it dispatches first, right, typically only because there is no fuel, but the energy serves the load that occurs in the middle of the day when the sun is up.

COMMISSIONER CLARK: So what does your load profile look like right now? What is TECO's peak? Are you summer peaking or winter peaking right now?

THE WITNESS: We are winter peaking.

COMMISSIONER CLARK: What's the disparity between your summer and your winter peak?

THE WITNESS: I would like to pass that on to Jim Rocha. He's got a better idea of the difference in winter to summer.

COMMISSIONER CLARK: Could you tell me what percentage of the installed capacity that you actually count toward your capacity requirements?

THE WITNESS: Again, I am going to ask that you ask Mr. Rocha that. I have got a guess, but I know that he knows the answer.

COMMISSIONER CLARK: And would I also ask him the dollar related questions that go along with that? In terms of how you calculate your installed costs, do you calculate that on the 145 megawatts of installed capacity, or do you count it toward what your actual capacity is towards your peak?

THE WITNESS: No, we count it on the maximum output of the project.

COMMISSIONER CLARK: Okay. So it has nothing to do with the capacity requirements that you have, you --

THE WITNESS: No, sir.

COMMISSIONER CLARK: -- if you recount -- let me ask it this way: If you recalculated your installed cost based on the capacity that you actually get real benefit from toward your capacity requirements, what would that average cost have been?

THE WITNESS: I don't know what that answer is. You know, I think, though, that for our summer peak, the assumption is that our solar would be producing -- would be producing a maximum output,

or near maximum output.
COMMISSIONER CLARK: Okay. One final question. What time does your summer peak occur in the day?
THE WITNESS: I believe -- again, I think you need to ask Mr. Rocha that question.
COMMISSIONER CLARK: Got it. Thanks.
CHAIRMAN GRAHAM: Commissioner Brown.
COMMISSIONER BROWN: Just another question that came to me.
Mr. Rehwinkel asked you a question about battery storage for this -- the first tranche projects. Are you considering adding a battery storage for the rest of the projects?
THE WITNESS: We continue to monitor battery storage. If it ever makes sense on a cost-effective, we would strongly consider adding storage at our solar sites.
COMMISSIONER BROWN: Are you tracking what other IOUs are doing?
THE WITNESS: We are. And we are talking to entities that are involved in battery storage. We just don't -- we are seeing the price on a downward trend, but we are not there yet, as far as cost-effectiveness goes.

COMMISSIONER BROWN: All right. Thank you.
CHAIRMAN GRAHAM: Redirect?
MR. WAHLEN: No redirect.
I believe Mr. Ward's Exhibit No. 2 is in the record already.
CHAIRMAN GRAHAM: Okay. Mr. Rehwinkel?
MR. REHWINKEL: Mr. Chairman, we would only move Exhibit 15. We didn't ask questions, really, about 13 or 14, so I am not going to move those in.
CHAIRMAN GRAHAM: All right. 15 is just the settlement, and I don't have a problem one way or the other, so we will go ahead and move it for simplicity.
MR. WAHLEN: No objection.
(Whereupon, Exhibit No. 15 was received into evidence.)
CHAIRMAN GRAHAM: All right. Would you like this witness excused?
MR. WAHLEN: I would love this witness excused.
CHAIRMAN GRAHAM: Mr. Ward, thank you for your time and your testimony.
(Witness excused.)
CHAIRMAN GRAHAM: This looks like a perfect time to take a five-minute break, and after that,

we will take the next witness, which is --

MR. WAHLEN: Mr. Rocha.

CHAIRMAN GRAHAM: Thank you.

(Brief recess.)

CHAIRMAN GRAHAM: Okay. Guys, let's come back to order, please. TECO your witness.

MR. WAHLEN: Thank you.

Whereupon,

JIM ROCHA

was called as a witness, having been previously duly sworn to speak the truth, the whole truth, and nothing but the truth, was examined and testified as follows:

EXAMINATION

BY MR. WAHLEN:

Q Would you please state your full name for the record.

A My name is Jim Rocha. I work at Tampa Electric Company. 702 North Franklin Street, Tampa, Florida.

Q And have you been sworn?

A I have.

Q Did you prepare and cause to be filed in this docket on December 14th, 2017, prepared direct testimony consisting of 20 pages?

A I did?

Q And then did you also prepare and cause to be filed in this docket on February 14th, 2018, revised prepared direct testimony consisting of 20 pages?

A I did.

Q And in general, why did you file the revised testimony on February 14th?

A As a result of the Tax Reform Act.

Q Okay. Thank you.

Do you have any additions or corrections to your revised prepared correct testimony?

A I do not.

Q If I were to ask you the direct testimony today, would you have answers be the same?

A They would.

MR. WAHLEN: Mr. Chairman, Tampa Electric Company requests that the revised direct testimony of Mr. Rocha, dated February 14th, 2018, be inserted into the record as though read.

CHAIRMAN GRAHAM: We will insert Mr. Rocha's revised testimony into the record as though read.

MR. WAHLEN: Thank you.

(Whereupon, prefiled revised direct testimony was inserted.)

TAMPA ELECTRIC COMPANY
DOCKET NO. 20170260-EI
FILED: 12/14/2017
REVISED: 2/14/2018

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

REVISED PREPARED DIRECT TESTIMONY

OF

R. JAMES ROCHA

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

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

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

A. I graduated from the Georgia Institute of Technology with a Bachelor's degree in Nuclear Engineering in 1982 and a Master of Science Degree in Nuclear Engineering in 1983. I earned a Master's degree in Business Administration from the University of Tampa in 1993, and I am a registered

Professional Engineer in the State of Florida.

In 1984, I was employed by Commonwealth Edison Company as a nuclear fuel engineer in the modeling of unit operation. In 1987, I joined Florida Power Corporation and became a resource planning engineer in the Generation Planning Department. In 2000, I became Manager of Financial Analysis at TECO Energy, responsible for business development and asset management. Since 2006, I have held several positions at Tampa Electric responsible for budgeting, business strategies and North American Electric Reliability Corporation ("NERC") Critical Infrastructure Protection ("CIP") and non-CIP NERC compliance.

I have over 30 years of accumulated electric utility experience working in the areas of resource planning, business and financial analysis, and engineering. I was appointed to my current position in December 2011.

Q. Have you previously testified before the Commission?

A. Yes. In 2012, I testified in Docket No. 20120234-EI in support of the company's petition for determination of need of the Polk 2-5 Combined Cycle Conversion Project.

I also served on the company’s panel of subject matter experts during the hearing on the 2017 Amended and Restated Stipulation and Settlement Agreement (“2017 Agreement”), held on November 6, 2017.

Q. What are the purposes of your revised direct testimony?

A. The purpose of my revised direct testimony is to: (1) describe the provisions in the 2017 Agreement recently approved by the Commission that allow cost recovery of solar generation projects through a Solar Base Rate Adjustment (“SoBRA”); (2) sponsor and explain the calculation of the revenue requirement for the company’s SoBRA for the two projects comprising the company’s first tranche of solar generation (“First SoBRA”) effective September 1, 2018; (3) demonstrate that the two projects in the company’s First SoBRA satisfy the cost-effectiveness test specified in the 2017 Agreement, and (4) confirm that the effects of recently enacted federal tax reform are reflected in Tampa Electric’s revenue requirement and cost-effectiveness calculations for the First SoBRA.

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

A. Yes, Exhibit No. __ (RJR-1) was prepared by me or under my direction and supervision. It consists of the following four (4) documents:

Document No. 1: Demand and Energy Forecast
Document No. 2: Fuel Price Forecast
Document No. 3: Revenue Requirements for First SoBRA
Document No. 4: Cost Effectiveness Test for First SoBRA

Q. How does your testimony relate to the prepared direct testimony of Tampa Electric witnesses Mark D. Ward and William R. Ashburn?

A. Tampa Electric witness Ward's direct testimony describes the two projects (Payne Creek Solar and Balm Solar) for which cost recovery is requested via the company's First SoBRA, as well as their projected in-service dates and installed cost per kilowatt alternating current ("kW_{ac}"). I use the projected installed project cost in witness Ward's direct testimony to calculate the annual revenue requirement for the First SoBRA. The company's cost of service and rate design witness, William R. Ashburn, uses the annual revenue requirement described in my direct testimony to develop the proposed customer rates for the First SoBRA.

2017 Agreement

Q. Please explain the origins of the 2017 Agreement.

A. The 2017 Agreement is an amendment and restatement of the company's Stipulation and Settlement Agreement ("2013 Agreement"), which resolved all of the issues in the company's last general base rate proceeding (Docket No. 20130040-EI).

Therein, among other things, Tampa Electric agreed that the general base rates provided for in the 2013 Stipulation would remain in effect through December 31, 2017 and thereafter until the company's next general base rate case. The 2013 Agreement also specified that Tampa Electric would forego seeking future general base rate increases with an effective date prior to January 1, 2018, except in limited circumstances.

The Florida Public Service Commission ("FPSC" or "Commission") approved the 2013 Agreement and memorialized its decision in Order No. PSC-2013-0443-FOF-EI, issued September 30, 2013 ("2013 Agreement Order").

In late 2016, recognizing that the period in which Tampa Electric agreed to refrain from seeking general base rate increases would expire at the end of 2017, Tampa Electric and Office of Public Counsel ("OPC") began discussing whether the company would be willing and able to (a) refrain from seeking a general base rate increase beyond December 31, 2017 and (b) extend the terms of the 2013 Agreement for an additional period. During those discussions, OPC requested and Tampa Electric provided extensive financial and other information to OPC regarding its financial condition and future business plans. The Florida Industrial Power Users Group, Florida Retail Federation, Federal Executive Agencies, and West Central Florida Hospital Alliance later joined the discussions and made their own requests for information. As a result of this extensive and time-consuming process, the five Parties reached an agreement with Tampa Electric to extend the 2013 Agreement with limited amendments, subject to Commission approval.

The Commission approved the 2017 Agreement on November 6, 2017 and memorialized its approval in Order No. PSC-2017-0456-S-EI, issued on November 27, 2017.

Q. Please generally describe the 2017 Agreement.

A. The 2017 Agreement amends and restates the 2013 Agreement, extends the general base rate freeze included in the 2013 Stipulation, limits fuel hedging and investments in natural gas reserves, protects customers if federal tax reform occurs and replaces the Generation Base Rate Adjustment ("GBRA") mechanism in the 2013 Agreement with a SoBRA mechanism.

The SoBRA mechanism in the 2017 Agreement includes a strict cost-effectiveness test and a $1,500 per kW_{ac} installed cost cap ("Installed Cost Cap") to protect customers.

The SoBRA mechanism will enable the company to significantly reduce its carbon emissions profile and its dependence on carbon-based fuels by installing and receiving cost recovery for up to 600 MW of photovoltaic single axis tracking solar generation. This major addition of solar generation will continue the company's transformation into a cleaner, more sustainable energy company, thereby improving fuel diversity and reducing its exposure to financial and other risks associated with burning carbon-based fuels. Because the fuel cost of solar generation is zero, it will provide an important measure of price stability to customers. The 2017 Agreement also allows the company to take maximum advantage of the existing 30 percent solar investment tax credit while the credit remains in effect, as well as bonus depreciation, for the benefit of customers.

Q. What are the key SoBRA cost recovery provisions in the 2017 Agreement?

A. There are several key provisions in the 2017 Agreement. First, subparagraph 6(b) of the 2017 Agreement authorizes Tampa Electric to seek recovery of up to 150 MW of new solar generation to be in-service on or before September 1, 2018 through a SoBRA. Per the 2017 Agreement, the effective date of the First SoBRA can be no earlier than September 1, 2018 and its maximum incremental annual revenue requirement may not exceed $30,600,000, with four months of cost recovery in 2018 capped at $10,200,000.

Second, subparagraph 6(d) of the 2017 Agreement specifies that the installed cost of each individual project to be recovered through a SoBRA may not exceed $1,500 per kW_{ac}. Witness Ward's direct testimony presents the projected installed costs per kW_{ac} for the two projects in the First SoBRA and shows that the projected costs are below this cap.

Third, subparagraph 6(g) of the 2017 Agreement states that the cost-effectiveness for the projects in a SoBRA tranche shall be evaluated in total by considering whether the projects in the tranche will lower the company's projected system Cumulative Present Value Revenue Requirement ("CPVRR") as compared to such CPVRR without the solar projects.

Fourth, subparagraphs 6(a) through 6(c) of the 2017 Agreement specify that, subject to the revenue requirement limits in subparagraph 6(b) of the 2017 Agreement, the SoBRA will be calculated using the company's projected installed cost per kW_{ac} for each project in the tranche (subject to the Installed Cost Cap); reasonable estimates for depreciation expense, property taxes and fixed O&M expenses; an incremental capital structure reflecting the then current midpoint Return On Equity and a 54 percent equity ratio, adjusted to reflect the inclusion of investment tax credits on a normalized basis.

Fifth, subparagraph 6(d) of the 2017 Agreement specifies that the types of costs of solar projects that traditionally have been allowed in rate base are eligible for cost recovery via a SoBRA, and lists the following types of costs as examples: Engineering, Procurement and Construction ("EPC") costs; development costs including third party development fees, if any; permitting fees and costs; actual land costs and land acquisition costs; taxes; utility costs to support or complete development; transmission interconnection costs; installation labor and equipment costs; costs associated with electrical balance of system, structural balance of system, inverters, and modules; Allowance for Funds Used During Construction (“AFUDC”) at the weighted average cost of capital from Exhibit B of the 2017 Agreement; and other traditionally allowed rate base costs.

Sixth, subparagraph 6(m) of the 2017 Agreement specifies that if the actual installed cost is less than the Installed Cost Cap, the company and customers will share in any beneficial difference with 75 percent going to customers and 25 percent serving as an incentive to the company. If applicable, this incentive will be added to the revenue requirement calculation.

Seventh, Subparagraph 6(j) of the 2017 agreement allows the company to seek recovery of unused capacity in a future petition for approval if the amount of capacity recovered in the SoBRA is below the maximum amount specified in Subparagraphs 6(b) and 6(c). For instance, if the First SoBRA is less than the allowed 150 MW, that difference could be added to the Second SoBRA.

Eighth, paragraph 9 of the 2017 Agreement addresses Federal Income Tax Reform. It provides a mechanism for calculating and implementing the impact of tax reform on Tampa Electric's base rates and charges to the benefit of customers.

Annual Revenue Requirement

Q. What is the annual revenue requirement for recovering costs associated with the two projects included in the First SoBRA?

A. The annual revenue requirement is $24.245 million. This amount was calculated using the projected installed costs of the two projects (Payne Creek Solar and Balm Solar) in witness Ward's direct testimony and in accordance with the revenue requirement cost recovery provisions of the 2017 Agreement. A summary of the annual revenue requirement calculation is shown in Revised Document No. 3 of my Exhibit No. __ (RJR-1).

Q. Please explain the assumptions used in your analysis.

A. The base assumptions for the calculation are the company's demand and energy forecast shown in Document No. 1 of my exhibit, the fuel forecast shown in Document No. 2 of my exhibit, and the solar property tax exemption. These same assumptions were used in setting Tampa Electric’s 2018 cost recovery factors and will be used in its Ten Year Site Plan to be submitted on April 1, 2018. The Investment Tax Credits (“ITC”) associated with the First SoBRA were normalized over the thirty-year life of the assets in accordance with applicable Internal Revenue Service regulations.

These assumptions were included in a model that considered the solar project costs along with the company’s incremental capital costs and agreed upon capital structure to arrive at a revenue requirement amount. Tampa Electric used the following capital structure: a 10.25 percent return on common equity using a 54 percent equity ratio and a 4.5 percent long-term debt rate on the remaining 46 percent debt in the capital structure.

Q. Please explain the calculation of the annual revenue requirement for the First SoBRA as presented in Revised Document No. 3 of my Exhibit No. ___ (RJR-1).

A. Using the capital expenditures presented by witness Ward, I calculated the book depreciation and the cost of capital using the capital structure above adjusted for accumulated deferred taxes. I also added property taxes and fixed operating expenses.

Q. Does the revenue requirement amount shown above reflect federal income tax reform?

A. Yes. The Tax Cuts and Jobs Act of 2017 was enacted by the United States Congress on December 20, 2017 and signed into law by the President of the United States on December 22, 2017. Therefore, Tampa Electric updated the revenue requirement in this revised testimony to reflect the tax changes. Specifically, the company updated the corporate federal tax rate. The change in the federal tax rate affects the after-tax weighted average cost of capital ("ATWACC") used in the calculation of the solar project revenue requirements and the projected system CPVRR used to determine cost-effectiveness, as described later in my testimony.

The federal corporate tax rate was lowered from 35 percent to 21 percent while the Florida corporate tax rate remained at 5.5 percent. This changed the ATWACC, which is used as the discount rate for all present value calculations, from 6.81 percent to 7.08 percent.

Q. Is this a final revenue requirement amount and how are customers protected?

A. No. Subparagraph 6(g) of the 2017 Agreement specifies that this annual revenue requirement amount will be trued up for the actual installed cost and in-service dates of the projects covered by the First SoBRA when it petitions for approval of its Second SoBRA. I did not include a true-up in the calculation of the First SoBRA, because this is the first solar tranche. After the in-service date of a tranche, when the actual costs are known, and contemporaneous with a fuel docket filing, Tampa Electric will include a true-up for each revenue requirement calculation.

Q. Does the annual revenue requirement presented in Exhibit No. ___ (RJR-1) reflect an incentive savings adjustment?

A. Yes. Subparagraph 6(m) of the 2017 Agreement contains an incentive designed to encourage Tampa Electric to build solar projects for recovery under a SoBRA at the lowest possible cost. According to subparagraph 6(m), if Tampa Electric’s actual installed cost for a project is less than the Installed Cost Cap, the company's customers and the company will share in the beneficial difference with 75 percent of the difference inuring to the benefit of customers and 25 percent serving as an incentive to the company to seek such cost savings over the life of this 2017 Agreement. The company has included the effect of the incentive in its revenue requirement for the First SoBRA based on projected costs.

Q. Does the 2017 Agreement include an example of how the incentive mechanism would work?

A. Yes. According to subparagraph 6(m), if the actual installed cost of a solar project is $1,400 per kW_{ac}, the final cost to be used for purposes of computing cost recovery under this 2017 Agreement and the true-up of the initial SOBRA would be $1,425 kW_{ac} [0.25 times ($1,500 - $1,400) + $1,400].

Q. What are the incentive calculations for the first tranche based on the company's projected installed costs?

A. Witness Ward projects the installed costs for the Payne Creek Solar and Balm Solar projects to be $1,324 kW_{ac} and $1,480 kW_{ac}, respectively, including interconnect, AFUDC, and land. For the Payne Creek Solar project, the incentive was calculated as [25% x ($1,500 - $1,324) + $1,324 = $1,368]. For the Balm Solar project, the incentive was calculated as [25% x ($1,500 - $1,480) + $1,480 = $1,485]. The total incentive included for both Payne Creek Solar and Balm Solar was $44 kW_{ac} and $5 kW_{ac}, respectively, so that it averages about $25 kW_{ac}.

Cost-Effectiveness Test

Q. Please describe the cost-effectiveness standard in the 2017 Agreement.

A. Subparagraph 6(g) of the 2017 Agreement states that the cost-effectiveness for the projects in a SoBRA tranche shall be evaluated in total by considering only whether the projects in the tranche will lower the company’s projected system CPVRR as compared to such CPVRR without the solar projects.

Q. Have you evaluated the two projects covered by the First SoBRA in light of this cost-effectiveness test?

A. Yes. The two projects covered by the First SoBRA lower the company’s projected system CPVRR as compared to such CPVRR without the solar projects; therefore, the projects covered by the First SoBRA satisfy the cost-effectiveness test in the 2017 Agreement. The calculations used to support this conclusion are based on the projected installed costs presented in witness Ward's direct testimony and associated incentive and are contained in Revised Document No. 4 of my exhibit.

Q. Please explain the underlying assumptions used to determine the projected system CPVRR, as reflected in Revised Document No. 4 of your exhibit.

A. In addition to the same assumptions used in the revenue requirement calculation, Tampa Electric developed a reference expansion plan with no solar and a second expansion plan case including the projects of the First SoBRA.

Q. How are the cost-effectiveness results affected by federal income tax reform?

A. Since the ATWACC is used as the discount rate for all present value calculations, the change in the federal tax rate results in changes to the net present value calculations, and hence it changes the cost-effectiveness CPVRR calculations.

Q. Please explain the projected system CPVRR calculations reflected in Revised Document No. 4.

A. Including the effects of tax reform, the differential CPVRR is favorable for customers by $136.6 million before any value for reduced emissions is included and $148.0 million when reduced emissions value is included. The CPVRR fuel savings are $198.5 million, averaging approximately $20 million per year. It would be expected that the projects of the First SoBRA, as a zero-variable cost resource generating during the peak of the daylight hours, would show the largest fuel savings. Tampa Electric tested the robustness of these savings to customers by calculating sensitivities on fuel prices and a market price forecast for carbon. The results confirmed that customer savings would occur under all scenarios.

Q. Please discuss other benefits of the First SoBRA tranche, including lower emissions.

A. The two solar projects included in the First SoBRA will decrease carbon dioxide (“CO_2”) emissions by over 200,000 tons per year, while in the early years, it will decrease nitrogen oxide (“NO_X”) emissions by hundreds of tons per year and sulfur dioxide (“SO_2) emissions by thousands of tons per year. Additionally, the solar projects will result in increased construction jobs and additional property tax revenues for the county. All the while, Tampa Electric will maintain competitive rates for customers which are expected to remain among the lowest of Florida’s investor-owned utilities.

Summary

Q. Please summarize your revised direct testimony.

A. The solar projects of the First SoBRA result in CPVRR savings of $136.6 million, while reducing air emissions and delivering fuel diversity and price stability for customers. These savings and the supporting calculations set forth in Revised Document Nos. 3 and 4 of my Exhibit No. ___ (RJR-1) reflect the effects of recently enacted federal tax reform. The assumptions are reasonable, the methodology sound, and the results comport with the provisions of the 2017 Agreement and the cost-effectiveness standards of the Commission. Tampa Electric, accordingly, requests approval of the First SoBRA by the Commission.

Q. Does this conclude your revised direct testimony?

A. Yes, it does.

BY MR. WAHLEN:

Q Mr. Rocha, did you also prepare and cause to be filed with your revised direct testimony a revised exhibit marked RJR-1 consisting of four documents, and identified as No. 3 in the comprehensive exhibit list?

A I did.

MR. WAHLEN: Okay. Mr. Chairman, I believe that has been admitted into the record by stipulation.

CHAIRMAN GRAHAM: Duly noted.

BY MR. WAHLEN:

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

A Thank you.

Good morning, Commissioners. I am Jim Rocha. My testimony shows that the two solar projects in our first SoBRA described by Mr. Ward are cost-effective under the test approved by the Commission when our 2017 agreement was approved.

I also sponsor and present the calculation of the annual revenue requirements for our first SoBRA, which was used by Mr. Ashburn to develop the customer rates for the first SoBRA, and it's about $24 million.

The cost-effectiveness test for the first SoBRA is set out in subparagraph 6(g) of the 2017 agreement. In short, the two projects covered by the first SoBRA lowered the company's projected system cumulative present value of revenue requirements, CPVRR, by $136 million as compared to the present value revenue requirements without the solar projects. Therefore, these projects covered by the first SoBRA satisfy the cost-effectiveness test in the 2017 agreement.

These estimated annual revenue requirements including incentive using the 2018 projects is, as I said, $24.2 million. I calculated this amount using the projected installed cost of the two projects in the information from Mr. Ward, and in accordance with the revenue requirement cost recovery provisions of agreement.

And this concludes my summary.

Q Thank you.

MR. WAHLEN: Mr. Rocha is available for cross-examination.

CHAIRMAN GRAHAM: Thank you.

Mr. Rocha, welcome.

THE WITNESS: Thank you.

CHAIRMAN GRAHAM: Quick question for you, is your tag -- is your tag number GTRECK.

THE WITNESS: Uh-huh, you know George P. Burdell?

CHAIRMAN GRAHAM: Yes, I do.

MR. WAHLEN: You just caused us to lose a bet, by the way. He said he would find a way to work that in, and we said he wouldn't.

CHAIRMAN GRAHAM: My next question was going to be, what does a nuclear engineer know about solar, but I will leave that for the intervenors.

Mr. Rehwinkel.

MR. REHWINKEL: Thank you, Mr. Chairman.

EXAMINATION

BY MR. REHWINKEL:

Q Good afternoon, Mr. Rocha.

A Good afternoon.

Q Georgia Tech used to be in the SEC, right?

A Yeah, back when they were good. Another one with another school in this city.

Q You are the witness who is designated to explain the 2017 agreement as it relates to the projects and their recovery of the revenue requirements, is that right?

A The cost-effectiveness in the revenue requirements, yes, sir.

Q Okay. And you have a copy of Exhibit 15 with you, which is the agreement, right?

A Yes, I do.

Q Okay. And as your testimony reflects, you are intimately familiar with paragraph six in that agreement?

A I love that section.

Q And you are testifying here about the costs that determine whether Tampa Electric is eligible to seek cost recovery, i.e., under the $1,500 cap?

A Yes, sir.

Q Now, you would agree that there are per kilowatt AC and aggregate revenue requirement caps in the agreement that either of which require you to bring the projects in under a certain threshold, is that right?

A Yes, and it's also the page not to exceed and no more than numbers.

Q Okay. Now, if the company were to, in the end, because the costs we are dealing with today are projected, right?

A Yes.

Q If, in the end, the company were to exceed the 1,500 kWac cap, or the revenue requirement cap that is in the table on page 10, would the company be required to absorb those costs below the line if you are to receive SoBRA recovery?

A I am trying to distinguish. Are you referring to just the revenue requirement cap, or the limit on the $1,500 of kW?

Q Well, let's pick either one of them.

A Okay.

Q Let's take the $1,500 kW cap first. If you brought a project in at 1,550 hypothetically, what would happen over the duration of the agreement -- you are in today because you got a project, let's say that hypothetically your Balm creek project, which is projected to be at 1,480, comes in at 1,550. For purposes of cost recovery under the SoBRA, what would your options be? Would you have to eat everything below -- above 1,500, below the line?

A So my understanding of the agreement is that within a tranche, if it was over 15 -- the whole tranche, it was over 1,500, we would put 1,500, and that remaining part would be subject to some future rate case at a depreciated value.

Q Okay. So -- but for purposes of the SoBRA, the base rate increase that you are going to be recovering under the agreement, you could only recover up to $1,500, correct?

A That is absolutely correct.

Q And you can reflect the amount over 15 -- this hypothetical amount over $1,500 on your surveillance

report for earnings surveillance purposes, right?

A   Correct.

Q   And once you get to -- let's say, that after the four years, hypothetically, you file a rate case that would be effective 1/1/22, the cost of the SoBRA -- the cost of the solar project would be in rate base, and as long as it had depreciated to a level below $1,500, you could recover that net book value in future rates?

A   That's correct, in that rate case, yes.

Q   Yes. Now, if that happened, that hypothetical occurred, the -- would there be a deferred tax impact generated from September 1, 2018, through let's say, January 1, 2022?

A   We would -- we will be keeping track of the deferred taxes, yes.

Q   Okay. So the customers would, even if they paid a depre-- a net book value based on what started off as a project that was above the threshold, their net book value would be recovered in that next rate case, but there would also be a deferred tax impact that would be reflected in the capital structure, is that right?

A   That's correct.

Q   Okay. We haven't talked much at all today about the revenue requirement cap, but there is a revenue requirement cap of $30.6 million on the first

tranche, is that right?

A   Yes, there is.

Q   And for the year 2018, it's one-third of that, or $10.2 million, is that right?

A   It will go into service in -- yes --

Q   Okay.

A   -- it goes into service September 1 --

Q   Okay.

A   -- if forecasted.

Q   Now, just for the record, your revenue requirement estimate based on projected costs would bring that project in somewhere in the $8 million range for the 2018 piece, is that right?

A   Yes.

Q   Okay. And that's under the 10.2 threshold?

A   Yes, sir.

Q   Okay. Now, we've heard a little bit today about the 25-75 threshold, do you know what I mean when I say that? To the extent you bring a project in under the $1,500 cap, the company gets to retain 25 percent of that difference.

A   Yes.

Q   All right. And so for purposes of my questioning here, if I call that the 25 percent incentive, you know what I mean, right?

A I will.

Q Okay. There is another incentive, and Mr. Moyle touched on it earlier, that the company is -- would be allowed to build and recover the last 50 megawatts of the 600 in 2022 if the 2018 and 2019 tranches come in at less than $1,475 kWac, right?

A Yes, Mr. Ward addressed that.

Q Okay. Now, I notice Mr. Ward stated that the -- and can we call that the 2022 incentive, just for --

A Okay.

Q Okay. And Mr. Ward stated his opinion that the 2022 incentive is based on a blended per kWac cost that's the two years combined; is that right -- is that your understanding?

A That is what he said, and I concur.

Q Okay.

A It is our unders -- it is our belief that we are going to come under that regardless.

Q Okay. So there is a possibility for the record that the Public Counsel and the company may have a disagreement about whether you can blend those two years, but is it your testimony that for purposes of this hearing on the 2018 tranche, you are under for the year if you bring your costs in at 1,404, you are well

under that, right?

A Yes, sir.

Q And is it also your intent -- would it also be the company's expectation that on a stand-alone 2019 basis, you would be able to bring that year in under 1,475?

A I believe they all are, but I would be subject to check on the -- the 2019 is the January of 2019?

Q Yes.

A Yes. Yes.

Q Okay. And so --

A I'm going to Tranche Three.

Q Whether we have a disagreement or not about whether those could be blended, that's an argument for another day, would you agree with that?

A I agree.

Q Okay. And Mr. Ward used -- he said you were at 1,404 blended within the year 2018, or the first tranche, and that -- I am going to -- I am going to paraphrase his testimony, but I heard him say you had $96 per kWac of head room that you could use if, say, the '19 projects happened to be more expensive, you would have that much freeboard, if you will, and still stay under 1,475 in order to be eligible for the 2022 incentive, is that fair?

A He -- that's the way he said it, but it he was referring to the -- that the incentive has 96 of headroom, but it would be the same purpose.

Q Okay. And again, that's an argument for another day if we even get to that point?

A Very good.

Q Okay. Now, you were in the room when I asked him the questions about the all-in-costs, were you not?

A Yes, I was.

Q Okay. And you would agree that the incentive, the 25 percent incentive requires that the costs that are included to be measured against the $1,500 threshold have to be all-in for that to be fairly calculated, right?

A Yes.

Q Okay. I think I can eliminate some questions because of the way he answered them, but let me just ask you this generally.

You agreed with his answers to my questions about the integrity of the incentives is based on the all-in-costs being accurately reflected in the final costs that will be trued up for this tranche, right?

A I concur.

Q Okay. And while -- I think in your testimony, if I could ask you to look at your exhibit RJR-1 Revised

Document No. 3.

A Okay.

Q All right. So what you show here is a revenue requirement in the top part of this page of total revenue requirement of 23,856. Do you see that?

A I do.

Q And that's in thousands, so that's 23,856,000?

A Correct.

Q FOM, can you just tell what this means?

A It's fixed O&M.

Q Okay. So when we talked about O&M included or excluded, is there some O&M that's included in the 1,324?

A In the --

Q Well, actually, do these revenue requirements correspond to that blended 1,404 for kWac?

A The capital RR is, and the land, is what corresponds to the 1,404. The FOM is essentially what we have forecasted to be $7 a kW a year for the FOM.

Q Okay.

A In our small Big Bend Power Plant solar facility, it's about 11. As Mr. Ward stated, we are negotiating now whether we will self perform or contract that out, and that is yet to be decided; but right now, we are using a lower number than one we've seen previously.

Q Okay. So when I am looking on this Revised Document 3 of RJR-1, which is, for the record, Exhibit 3, the 20,548,000 and the 2,271,000, or million -- 2.271 million and the 20.548 million, those two numbers added together is, it looks like it's in the -- close to 23.8 million --

A Yes, sir.

Q -- something like that. Those numbers equate to the 1,404 blended?

A Yes. Those are the revenue requirements that are a result of that 1,404.

Q Okay. And then when I look down at the bottom of the page, this shows a -- those corresponding numbers are with the incentive, so you have 20,938,000 and the same 2.271 million for land rate of return --

A Correct.

Q -- is that right?

Is the difference between 20,548 and 20,938, is that the incentive that you would earn if these numbers come in as actual?

A Yes. It's about 389,000 for this tranche.

Q Okay. So those costs that you have projected here, they will likely vary just based on whatever your actuals are, up or down, right?

A Yes, and then they will be trued up.

Q Yes, okay.

Now, does it make a difference -- when you are calculating the incentive, is it done on an aggregate -- the 25 percent incentive, is it done on an aggregate basis or is it done by project?

A We executed it on this last version by project and looked at each one compared to $1,500 all in for kW.

Q Okay. So there was relatively small amount of incentive at the $1,480 level for the Baum Road project, right?

A Yes.

Q And there was a relatively larger amount of incentive for the Payne Creek project, right?

A That's correct.

Q And what you are reflecting here on RJ -- on document three is putting those two together and calculating the incentive, correct?

A In the total line, yes. You can see each project one if you just subtracted those two.

Q Okay. In -- can you give an explanation to the Commission why the incentive changed when the tax law changed? Because I know, if you compare your original testimony to this, there is something, I think, about $30,000 more incentive based on the same numbers.

Can you explain why that would have fluctuated if -- and you would say income taxes are not part of the 1,324 or 1,480, right?

A They are not in the capital costs, no.

Q Okay.

A But when I go to revenue requirements, I am going to calculate an ROE, and then I am going to pretax it up using the tax rate. And in this case, after the tax reform, that rate was lower, lowering the total incentive.

Q So if AFUDC is included in the costs, that's where that would find its way into the difference?

A Well, we get the ROE on AFUDC plus our capital --

Q Okay.

A -- and then that result would have an ROE component to it, which would become pretax. So you would call it taxes effect of the ROE, or you can just say it's the pretax component.

Q Okay. So a lower tax rate on the equity component of AFUDC is going to somewhat reduce the incentive because the costs that are at issue are just a little lower, right?

A Correct.

Q Okay.

A It also lowered the rest of the revenue requirements for all the -- the total totality of the project, not the incentive portion.

Q Right. And you have reflected the income tax adjustment, as required by the agreement --

A Correct.

Q -- in this new revised RJR-1 document?

A Yes, I did.

Q And those numbers are what Mr. Ashburn then goes out and calculates customer numbers?

A Exactly these numbers.

Q Okay. Just a few more questions about that. Somebody has gotten smart and turned the air conditioning off in here so I keep my questioning short.

We talked a little bit about the -- well, first of all, you reflect here in RJR-1, document three, a total revenue requirement of 24,245,000 after inclusion of the fixed O&M, the return on the land and the incentive; right?

A Yes.

Q Okay. Ordinarily, I think of depreciation being calculated based on plant in service and original cost of that plant. Do you --

A Yes.

Q -- do you agree with that?

A Yes.

Q I believe I have seen documents that indicate that depreciation expense would be calculated based on the plant costs and the incentive. Can you --

A Okay.

Q -- explain why I might have seen that, and if I am wrong about that?

A Okay. The -- let's start with the example of a $1,400 kW project, so there is $100. 1,425 would be what we would calculate revenue requirements against. Revenue -- that -- the capital is the 1,400. For purposes of calculating the extra incentive of $25 of kW, it would be capital, and the capital has return components of depreciation, ROE, a return on the debt and then gross -- the first taxes.

And that is our position of -- you know, it says the incentive will be based on capital costs -- or costs -- costs, which I would -- I read to be the way I just described.

I will point out that the incentive, although, in this case adds 389,000, had we done what we will not do, which is build up to. That would have been 1.67 -- six or seven -- $6 million more to customers, and so the incentive was that little agreement to encourage us to keep costs low to customers.

Q Right. So the incentive is -- it's recorded by the company as for the benefit of shareholders, and I am not going to get into how the accounting works on that, but that's shareholder -- extra shareholder money because they've done a good job in getting prices or costs as low as possible, right?

A Yes. It's revenues. It's for the revenue calculation only. Our accountants will only focus on the true actual costs of capital.

Q Right. So -- and let's say you come in for that hypothetical 1/1/22 rate change, base rate change, that component of rates will disappear, would you agree with that, once rates are changed and these solar projects go into rate base?

A It will -- yes, it will be treated just like every other rate base item.

Q Okay. So in your example of the 1,425, it would be 1,425 times the number of kW, and those would be the dollars that, minus any depreciation, so the net book value of that original starting point is going to go into rate base, but that $25 is not going to go into rate base in that 1/1/22 base rate rate change; right?

A I agree with you.

Q Okay. And so just a minor technical question about the dep -- so any depreciation that was occurring

on that $25, that's no longer going to occur, right?

A It would never occur. It would only be the real dollar -- the real capital in the depreciation.

Q Okay. Now, in that period of time, when depreciation is occurring on the -- well, you are reflecting a depreciation of that capital cost component of the $25 --

A Right.

Q -- is there going to be a deferred tax, or a tax timing difference created?

A No, sir.

Q All right.

MR. REHWINKEL: Mr. Chairman, those are all the questions I have for Mr. Rocha.

Thank you for your time and answers.

THE WITNESS: Thank you.

CHAIRMAN GRAHAM: Mr. Moyle.

MR. MOYLE: Thank you, Mr. Chairman.

EXAMINATION

BY MR. MOYLE:

Q Good afternoon, Mr. Rocha.

A Good morning -- good afternoon.

Q You had a couple of questions punted to you, and let me see if I can tackle those off the bat.

You were just talking to Mr. Rehwinkel about

the incentive mechanism. Do you know a bottom line dollar amount that the ratepayers saved, if you will, if you would assume they come in at that number?

A I would just -- it's the 1.6 minus the about four, so about 1.2.

Q Okay. And some of these proceedings -- this is the second set of proceedings that this commission has heard. Sometimes they get issues and ask questions, and it may lead to them making policy through rule-making. So I am going to ask you some questions to try to develop a little bit of a record with respect to that incentive issue.

Do you think that incentive is a good idea?

A I think that incentive accom -- yes, because it accomplishes to make sure that we brought in costs as low as possible.

Q All right. And you are the only utility that has that incentive mechanism, right?

A I don't know the answer.

Q Okay. How did you do your cost-effectiveness calculation?

A So as per the agreement, we did the cumulative present value revenue requirement without any solar projects being added, and then we redid that same calculations by adding Tranche One into it, and it's a

30-year present value.

Q So you limited your analysis just to what was in the settlement agreement, correct?

A Yes, sir.

Q Okay. How did you go about doing the analysis with respect to the cumulative present value?

A We have spreadsheets for the capital costs of the expansion plan. We have our normal dispatch model, which is planning and risk that we use that does the fuel and purchase power costs out for the 30-year time period. And we have fuel forecasts are the big input, and then we mentioned the customer demand and energy forecast.

Those things are used to dispatch the system, and we use a after-tax weighted average cost of capital based upon our target capital structure, and that rate is used to bring all the numbers back to the current time period.

Q So those were your inputs into your calculation, is that right?

A Yes, sir.

Q I didn't hear you mention cost of carbon. Was that something you considered as well?

A We do consider it. We, in this presentation, have put it sort of below the line so that you can see the number with and without. And we are supporting the number without, but we wanted to continue to track those costs and savings of emissions.

Q And the Chairman, I think, referenced you have a background largely in nuclear engineering, is that right?

A It's been a long time, but yes.

Q Right. Right.

In the fuel cache, you are not a fuel forecast expert person, are you?

A No.

Q You just rely on information that's provided to you by third parties with respect to the fuel forecasts and then plug them into a formula?

A We have a -- from our fuel department, who does it, but they use those tools and their staff asks questions where we described how that was crafted.

Q All right. Do you know, is the fuel forecast something that is developed by TECO internally, or do you rely on third parties; or is it a combination? Can you just tell me how it works?

A It's a combination of early years. It's a market value, like for natural gas would be the NYMEX Futures future. In the mid-period, we will use a reputable forecasting like PIRA or Wood Mackenzie. In

the longer term, we will look to the EIA forecast.
Q Okay. And you had said you also have, as an input, the customer demand in he and energy. Could you just explicate a little bit more what that is?
A Our load forecasting group, which all utilities have, have the whole section in our 10-year site plan describing how they put together all these tools. But essentially they are looking at many years of data and feedback mechanisms of GDP, and customer growth, and population, and economy, and new standards that come in for conservation; and they forecast every, for us, each -- the amount of energy for each year and the peak demand for winter and summer. And we -- then they also provide for us a load shape. And so now we have 8760 of every year for 30 years.
Q Are you familiar with the inputs, like if I asked you questions about the load forecast, would you be able to answer them, do you think?
A I can go at least as far as I put the annual numbers in for the load forecast, and I can go a certain level.
Q Okay. And what's the -- do you know what the reserve margin is for this year that, as we sit here, without solar?
A I just went blank, because we just put in

our -- our Polk 2 combined cycle unit, and I have reserve margins, if I can just borrow it from our 10-year site plan.

So we are at 26 percent this summer, and next year, APPA falls off and we will be at 21 percent in the summer.

Q So '18 is 26?

A Yes. And we just added 460 megawatts of Polk 2.

Q So does the 26 take into account the Polk numbers or no?

A Yes, it does.

Q Okay. And then solar is additive to the 26 percent?

A For the portion that comes in, yes --

Q Okay.

A -- with the capacity value that the Commissioner asked about.

Q Okay. And then let's talk about the capacity value a little bit.

A Okay.

Q How do you determine the capacity value?

A I don't have real live actual data, so we have a profile from the vendors using PVsyst, it's a well recognized software for solar depending on the GPS coordinates and rainfall, et cetera.

So we get a 8760 profile, and statistically, we are looking at, from our load forecasting group, what hour is our coincident peak. And, say, in the summer, it's 5:00, maybe a little later, six o'clock p.m., maybe sometimes earlier. And then in the winter, it would be January on one of those cold days that we have in Tampa.

And so we statistically looked at what -- how much the solar was generating at that hour. It could have very easily been at its max cap at two o'clock in the afternoon, but at five o'clock the sun had gone further to the horizon.

So we calculated about 46.6 percent for the full year on average. It's for reserve margin purposes that we use 51 in August.

Q Do you peer review with respect to the reserve margin calculations that are used by other Florida utilities?

A There has been a lot of IOUs working with FRCC to try to arrive at common understanding, and so we've been -- that's been interrogatories posed by staff and by FRCC to try to get there. And with more data, I think we will get more together on what that can contribute to peak.

Q Can you tell us where that process is now in

terms of the numbers, the range? I mean, are you at 48 to 52, or does it seem to be settling on 51?

A I will say to you that tracking gets you better at the peak than fixed has historically. So that -- I would put that at the upper end. And there is so many showers statistically, you also have those issues.

I have seen fixed in the thirties in 10-year site plan submittals.

Q Is 51 percent a high -- the high number?

A I think one to the south of us might have a little bit higher, but in the fifties.

Q And when you say to the south, are you talking about a utility or a particular plant?

A Yeah. I don't know the rainfall levels in that southern utility, so ours is 51 percent in August right now statistically.

Q Right. So just to be clear, I don't -- but when you say -- you don't look at these by individual plant, right? I mean, you look at -- your reference is to a utility, right?

A Yes, sir.

Q Okay. And maybe to the southeast of you?

A Yes, sir. And I pull up all of the numbers from the 10-year site plans, and we share a little bit on FRCC on the interrogatories.

Q Okay. So -- and I am familiar with some other cost-effective analysis that assumed a number of scenarios, like, you know, high fuel, high carbon, low fuel, low carbon, and they either do, like, a six box or a nine box calculation. I didn't see any of that in your testimony?

A Okay.

Q Did I -- did you guys do that?

A I did it in interrogatories what with a high fuel, a low fuel, and then we have a high, medium and low carbon forecast. Low is zero, and that there won't be one. And those were included in interrogatories.

Q Okay.

A And it was cost-effective in all of those.

Q All right. There were no scenarios that resulted in a customer's taking it on the chin even in a small degree?

A No, sir.

Q And of course, as part of the agreement, that's a guaranteed proposition, right, going forward?

A Well, I -- no, sir. I am in the forecast business.

Q I didn't think you were going to say yes to that question.

I want to ask you a few questions about the federal tax incentives and how those are playing out with respect to your SoBRA process.

If I understand it, the tax incentives are winding down as time goes forward, is that right?

A They are currently at 30 percent. They are winding down to 10 percent, and will remain at 10 percent for ITC.

Q Okay. And do you expect that to have a material impact on the costs for which you bring in the future SoBRA projects?

A All of our SoBRA projects should be able to mostly use all 30 percent as long as you begin construction or in spending money by 2019.

Q Okay. And you told Mr. Rehwinkel that you made some revisions to your testimony based on the federal tax reform legislation that passed. Did that federal tax reform legislation do anything with respect to tax credits for solar or wind, if you know?

A Not to the ITC. It just lowered the tax rate on -- after you dep -- for net income.

Q Okay. Did it do anything with respect to solar in any other way?

A It also affected the after-tax weighted average cost of capital, and actually it was a little bit unfavorable because it increased the ATWACC by 0.2 percent, making future benefits worth a little less in net present value, although in nominal dollars they are still out there.

Q Okay. You had a little conversation with Mr. Rehwinkel about O&M, and you said it would add $7 per year; is that right?

A $7 per kW year, yes.

Q Per kW year. So with respect to -- just give me the calculation with respect to what that number would look like with what you have presented to the Commission today, you know, you were in at 1,425, I think your cap was 1,500. If you added seven bucks, where would that put things?

A Well, it's not a capital thing, and you would have to -- if I was going to do it as an economist, I would MPV it all back to times zero and try to create what is it worth today, but that's not what -- it's not capital. It's an operating revenue requirement.

Q Right. I understand that. I am just trying to get a sense of order of magnitude.

A Well, just the $7 per kW right there, but you are only looking -- that's only one year worth of it, right. I would try to MPV it, and I don't have that in my head.

Q Do you think -- and, again, back to the point about possibly looking at every cost, all in, if the Commission decides to engage in rule-making, do you think that that should being something that should be considered, O&M costs?

A I absolutely agree, and it is used for cost-effectiveness tests when we look at the annual refer requirements versus what we would have spent.

Q And just so I have a clear record on that, explain to me how you do use it.

A Okay. I -- also, for the capital, I calculate an annual ROE and an annual FOM, an annual property taxes, and any other expense, fuel, if it was that type of power plant, and this one isn't, and then MPV all of those back. I don't use the 1,500. I use it as an input to create the annual cost to customers, and then MPV all of those back.

Q Okay. You were able to take advantage of the tax exemption, ad valorem tax exemption on the properties that are being talked about here; is that right?

A That was another item that helped solar be cost-effective.

Q Okay.

MR. MOYLE: If I can -- one moment.

CHAIRMAN GRAHAM: Sure.

MR. MOYLE: That's all I have. Thank you.

CHAIRMAN GRAHAM: All right. Staff.

MR. TRIERWEILER: Staff has no questions for this witness.

CHAIRMAN GRAHAM: Commissioners.

Commissioner Clark.

COMMISSIONER CLARK: Thank you, Mr. Chairman. Just a couple of questions to follow up earlier.

I want to go back to Mr. Moyle's question regarding your O&M costs. I think you were trying to get to a specific number, $7 a kW, you are looking at $1 million a year in operation maintenance cost, is that correct?

THE WITNESS: Yes, just under that.

COMMISSIONER CLARK: Under $1 million, okay.

A question I had asked Mr. Ward earlier relating to where solar fits into your load profile, are you using this generation source as base, intermediate or peak?

THE WITNESS: It is base. It's right -- it goes first.

COMMISSIONER CLARK: So in relation to using it in your base, in the case where it is not there to meet some of your capacity requirements, what you have to dispatch then?

THE WITNESS: We use the same type dispatch models we use, but it's going to go to whichever of our solid fuel or combined cycle next; and then during the peak of the day, it will go to the peakers.

COMMISSIONER CLARK: Most likely solar is going to actually be displacing gas generation in most cases, is that correct?

THE WITNESS: It will. It is most likely gas, and it's most likely peaking during the higher load days and sometimes either, depending only coal or gas prices, it could go to one of those a little bit.

COMMISSIONER CLARK: When you calculate your install costs and you look at the efficiency, or the savings of that unit, do you take into consideration that, especially at a 50-percent capacity rating, that you still don't forego having to build capacity to serve the consumers?

THE WITNESS: We build to the peak, which is at five o'clock, but this is still contributing lots of energy savings, and some -- and that can, on the economic value, brings value to the customer. So sometimes your folks might bill be a little bit bigger, a little bit different techno -- intermediate or base in order to create that lower fuel savings. But a prior higher order requirement is to hit the 20 percent reserve margin at the five o'clock peak in summer, and at the 7:00 a.m. peak in winter.

COMMISSIONER CLARK: So -- but you said you build -- you build to meet the peak; and realizing you have summer peak and a winter peak, your entire fleet performance is built and designed to meet the maximum peak, which is in your winter?

THE WITNESS: So the amount of megawatts I need, Commissioner, is based on the reserve margin. What I build is about the most cost-effective for that load shape that you described that changes every day, and there will be some impact of dispatch to intermediate generation like solar that we are beginning to do studies on. So far, the levels we are talking, we shouldn't have those operational issues yet.

COMMISSIONER CLARK: Okay. Thank you.

THE WITNESS: Yeah.

CHAIRMAN GRAHAM: Commissioner Polmann.

COMMISSIONER POLMANN: Thank you, Mr. Chairman.

Good afternoon, sir.

We've had quite a bit of discussion today regarding $1,500 per kilowatt AC. I would like to delve into that just a little bit more.

If we could look at the stipulated agreement, which is identified as Exhibit 15. I believe you have a copy of that.

THE WITNESS: I do.

COMMISSIONER POLMANN: If you could look, please, at page 11.

THE WITNESS: I am there.

COMMISSIONER POLMANN: We've already looked at this sentence starting on line four, carrying over to line five. And this refers to a tranche. I don't know if that word is defined in this document. I am not going to look for it, but the key point here I would like to bring into this line of questioning is that the tranche may consist of a single project or multiple individual projects. You agree?

THE WITNESS: Yes, sir.

COMMISSIONER POLMANN: It could be either one or several?

THE WITNESS: Yes. Mr. Ward explained, we have 210 projects, two of them in Tranche One.

COMMISSIONER POLMANN: Yes. Now, with regard to a tranche specifically different from a project, in my experience, a tranche is used -- that concept is really a convenience for maybe financing, or contracting, or managing. In your first tranche here, you have got two projects, and you are kind of using it that way, you have got --

THE WITNESS: Yes.

COMMISSIONER POLMANN: -- a contractor and so forth.

THE WITNESS: My understanding is the same as yours.

COMMISSIONER POLMANN: You know, it's really for program implementation, and we've had a number of questions here about how that relates to the $1,500. It's not necessarily that you are using the tranche for accounting, is that a fair statement?

THE WITNESS: So it is a fair statement to say that the word tranche was just our word to describe the collection of projects that make up that in-service date. The way this stipulation was written, that collection of projects are subject to the maximums and not to exceed requirements.

COMMISSIONER POLMANN: Okay. Thank you.

I would like to carry on with that on page 13 --

THE WITNESS: Okay.

COMMISSIONER POLMANN: -- if we could go there in the same document, in the first several lines; in particular, line two and three, which is where we do have a definition of installed cost cap. And here, if we could just look at that, the $1,500 per kilowatt AC speaks specifically the installed program installed cost cap after project; you would agree?

THE WITNESS: I agree that's exactly what it says.

COMMISSIONER POLMANN: It's specific to the project?

THE WITNESS: Yes.

COMMISSIONER POLMANN: And then I don't see any reference in that definition to a tranche; do you agree with that, sir?

THE WITNESS: I do not in that sentence.

COMMISSIONER POLMANN: Okay. So you do agree that it's not there?

THE WITNESS: It is not in that sentence. I agree.

COMMISSIONER POLMANN: All right. Then on line -- the next line down, would you agree that that indicates in the settlement agreement in the stipulation the installed cost cap shall apply on a per project basis?

THE WITNESS: That is what it says in those words.

COMMISSIONER POLMANN: All right. The rest of the sentence, it says: Includes all costs required to make each of the projects in the tranche fully operational. So even though there is a reference to a tranche, the cost does not apply other than to a single project?

THE WITNESS: I see your point. I have been informed that the intent of the parties was to -- that it's at the tranche level. I don't have an answer for you on the company position on that.

MR. MOYLE: I should probably register a hearsay objection at this point in terms of him being informed as to what the parties' intent was, but there is probably some better witnesses that could talk about parties intent that are already here to be under oath.

CHAIRMAN GRAHAM: I agree.

COMMISSIONER POLMANN: Mr. Rocha, I am asking if you could simply read into the record, or agree

with me for the record that those are the words
that are in this document.

THE WITNESS: I agree that in this section of the document those are the words, and the whole document should be read in harmony, but I leave it to the other witness that will be needed.

COMMISSIONER POLMANN: Okay. I am reading here the installed cost cap shall apply on a per project basis, and you have agreed with those simple words.

Sir, I will ask you, as a witness, you have confirmed that Tampa Electric Company is pursuing 10 projects. And can you please direct this commission to any evidence in this docket where the defined term installed cost cap is applicable in any manner other than on a single project basis? Is there any evidence that you are aware of in the docket where dollars are addressed other than project by project?

THE WITNESS: No, sir. It's only addressed in the 1,475.

COMMISSIONER POLMANN: Thank you, Mr. Chairman.

CHAIRMAN GRAHAM: Commissioner Brown.

COMMISSIONER BROWN: Thank you. And this

question may have been asked already, but since the install date on the first tranche projects are expected to be in September 2018, you intend to file the true-up cost in this year's fuel proceeding, is that correct?

THE WITNESS: No, not this year, because it won't be in service yet. We won't have all the actuals. It could be the next year. I don't know the exact timing of it, but it -- that is my understanding, it would be a year from now.

COMMISSIONER BROWN: Okay. Thank you.

CHAIRMAN GRAHAM: Redirect?

FURTHER EXAMINATION

BY MR. WAHLEN:

Q I think there may have been confusion about headroom. You remember Mr. Rehwinkel asked you about headroom?

A Yes.

Q And we have 1,404 is the weighted average cost of the two projects in the first tranche, is that right?

A That's correct.

Q Okay. So the headroom against the installed cap is how much, are $96?

A $96 of kW.

Q Okay. And the headroom against the 1,475

incentive is?

A 25, less than that, 71.

Q 71. Just checking your Georgia Tech math.

A Oh, God, here it comes.

MR. WAHLEN: Those are all my questions.

CHAIRMAN GRAHAM: All right. Exhibits? We don't have any.

MR. WAHLEN: Mr. Rocha's exhibit is already in the record.

CHAIRMAN GRAHAM: Okie-doke, would you like to excuse this witness?

MR. WAHLEN: Please.

CHAIRMAN GRAHAM: Thank you for your testimony, sir.

(Witness excused.)

CHAIRMAN GRAHAM: All right. It's finally cooling off here, but I still think it's a good time for a five-minute break before our last witness. We will come back at 4:35.

We are in recess.

(Brief recess.)

CHAIRMAN GRAHAM: Okay TECO, your final witness.

MR. BEASLEY: We call William Ashburn, Mr. Chairman.

Whereupon,

WILLIAM R. ASHBURN

was called as a witness, having been previously duly sworn to speak the truth, the whole truth, and nothing but the truth, was examined and testified as follows:

EXAMINATION

BY MR. BEASLEY:

Q Sir, would you please state your full name for the record?

A William R. Ashburn.

Q And have you been sworn in this proceeding?

A Yes.

Q Who is your current employer, and what is your business address?

A I am employed by Tampa Electric Company as Director of Pricing and Financial Analysis. My business address is 702 North Franklin Street, Tampa, Florida, 33602.

Q Mr. Ashburn, did you prepared and cause to be file in this docket on September 14, 2017, prepared direct testimony consisting of 11 pages?

A Yes.

Q Did you also prepare and submit in this proceeding on February 14, 2018, a document entitled Revised Prepared Direct Testimony of William R. Ashburn,

consisting of 11 pages?

A   Yes.

Q   In general, could you describe the revisions to your prepared direct testimony?

A   Very little to the testimony. Mostly to the exhibits.

When the tax reform occurred, Mr. Rocha changed the number to reflect the tax reform, and then that changed the rates, so I had to redo all the rate design reflecting a lower revenue requirement, and that changed all the exhibits.

Q   Thank you.

Do you have any additions or corrections to your revised direct testimony?

A   No.

Q   If I were to ask you the questions contained in your revised prepared direct testimony today, would your answers be the same as contained there?

A   Yes.

MR. BEASLEY: Mr. Chairman, I would like to request that the revised prepared direct testimony of Mr. Ashburn, dated February 14, 2018, be inserted into the record as though read.

CHAIRMAN GRAHAM: We will insert Mr. Ashburn's revised direct testimony into the record as though read.

MR. BEASLEY: Thank you.

(Whereupon, prefiled revised direct testimony was inserted.)

TAMPA ELECTRIC COMPANY
DOCKET NO. 20170260-EI
FILED: 12/14/2017
REVISED: 2/14/2018

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

REVISED PREPARED DIRECT TESTIMONY

OF

WILLIAM R. ASHBURN

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

A. My name is William R. Ashburn. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Pricing and Financial Analysis.

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

A. I graduated from Creighton University with a Bachelor of Science degree in Business Administration. Upon graduation, I joined Ebasco Business Consulting Company where my consulting assignments included the areas of cost allocation, computer software development, electric system inventory and mapping, cost of service filings and property record development. I joined Tampa Electric in 1983 as a Senior Cost Consultant in the Rates and Customer Accounting Department. At Tampa Electric I have held a series of positions with responsibility for cost of service studies, rate filings, rate design, implementation of new conservation and marketing programs, customer surveys and various state and federal regulatory filings. In March 2001, I was promoted to my current position of Director, Pricing and Financial Analysis in Tampa Electric's Regulatory Affairs Department. I am a member of the Rate and Regulatory Affairs Committee of the Edison Electric Institute ("EEI").

Q. Have you previously testified before the Commission?

A. Yes. I have testified or filed testimony before this Commission in several dockets. Most recently I testified for Tampa Electric in Docket No. 20170210-EI as a member of a panel of witnesses during the November 6, 2017 hearing on the 2017 Amended and Restated Stipulation and Settlement Agreement ("2017 Agreement"). I also testified on behalf of Tampa Electric in Docket No. 20130040-EI regarding the company's Petition for an Increase in Base Rates and Miscellaneous Service Charges and in Docket No. 20080317-EI which was Tampa Electric's previous base rate proceeding. I testified in Docket No. 20020898-EI regarding a self-service wheeling experiment and in Docket No. 20000061-EI regarding the company's Commercial/

Industrial Service Rider. In Docket Nos. 20000824-EI, 20001148-EI, 20010577-EI and 20020898-EI, I testified at different times for Tampa Electric and as a joint witness representing Tampa Electric, Florida Power & Light Company ("FP&L") and Progress Energy Florida, Inc. ("PEF") regarding rate and cost support matters related to the GridFlorida proposals. In addition, I represented Tampa Electric numerous times at workshops and in other proceedings regarding rate, cost of service and related matters. I have also provided testimony and represented Tampa Electric before the Federal Energy Regulatory Commission ("FERC") in rate and cost of service matters.

Q. What is the purpose of your revised prepared direct testimony?

A. The purpose of my revised prepared direct testimony is to: (1) describe the provisions in the 2017 Agreement recently approved by the Commission that govern the cost of service and rate design for a Solar Base Rate Adjustment ("SoBRA"); (2) sponsor and explain the proposed rates and tariffs for the company's First SoBRA, effective September 1, 2018; and (3) confirm that the proposed rates and tariffs reflect the effects of recently enacted federal tax reform.

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

A. Yes, Revised Exhibit No. ____ (WRA-1) was prepared under my direction and supervision. It consists of the following six documents:

Document No. 1	Development of First SoBRA Base Revenue Increase by Rate Class
Document No. 2	Base Revenue by Rate Schedule
Document No. 3	Rollup Base Revenue by Rate Class
Document No. 4	Typical Bills Reflecting First SoBRA Base Revenue Increase
Document No. 5	Redlined Tariffs Reflecting First SoBRA Base Revenue Increase
Document No. 6	Clean Tariffs Reflecting First SoBRA Base Revenue Increase

Q. How does your direct testimony relate to the direct testimony of Tampa Electric witnesses Mark D. Ward and R. James Rocha, filed concurrently in this docket?

A. Tampa Electric witness Mark D. Ward's direct testimony describes the two projects (Payne Creek Solar and Balm Solar) for which cost recovery is requested via the company's First SoBRA as well as their projected in-service dates and installed cost per kilowatt alternating current ("KW_{ac}"). Tampa Electric witness R. James Rocha's revised direct testimony presents the annual revenue requirement for the company's First SoBRA using the projected installed project costs presented in witness Ward's direct testimony, and is revised to include the changes to revenue requirements caused by the recent tax law changes. I use the annual revenue requirement from witness Rocha's revised direct testimony to develop the proposed base rate adjustment for the First SoBRA.

2017 Agreement Guidance for SoBRA

Q. Please describe how the 2017 Agreement calls for the SoBRA revenue requirements to be allocated to rate classes.

A. The 2017 Agreement directs that the SoBRA revenue requirements be allocated to rate classes using the 12 Coincident Peak ("CP") and 1/13th Average Demand ("AD") method of allocating production plant and be applied to existing base rates, charges and credits as described by the following two principles:

1. Only 40 percent of the revenue requirement that would otherwise be allocated to the lighting rate class under the 12 CP and 1/13th AD methodology shall be

allocated to the lighting class through an increase to the lighting base energy rate, and the remaining 60 percent shall be allocated ratably to the other classes.

2. The 12 CP and $1/13^{th}$ AD allocation factor used to derive the revenue requirement allocation shall be based on factors used in Tampa Electric's then most current energy conservation cost recovery ("ECCR") clause filings with the Commission.

Q. Once the revenue requirement has been allocated to rate classes, how will the SoBRA rates to recover each class's revenue requirement be designed?

A. The 2017 Agreement requires the following three principles be employed when designing the base rate adjustments for SoBRA:

1. The revenue requirement associated with SoBRA will be used to increase demand charges for rate schedules with demand charges and energy charges for rate schedules without demand charges.
2. Within the GSD and IS rate classes, the allocated SoBRA revenue requirement will be applied to non-

3. The billing determinants used to derive the base rate adjustments shall be based on factors and determinants used in Tampa Electric's then most current ECCR clause filings with the Commission.

Q. Do you provide an exhibit that shows the results of applying the allocation methodology called for in the 2017 Agreement?

A. Yes. Revised Document No. 1 of my exhibit was prepared for that purpose. That document, titled "Development of SoBRA Base Revenue Increases by Rate Class," shows how the revenue requirement increase described in witness Rocha's direct testimony was allocated across the rate classes. First, the 12 CP and 1/13th AD allocation factor utilized to set 2018 ECCR clause rates was used to allocate the total revenue requirement increase to all rate classes. Then, the part that was allocated to the Lighting class was split 60/40, with 40 percent recovered from the Lighting class and the remaining 60 percent reallocated to the other rate classes using the same 12 CP and 1/13th AD allocation factor (less the lighting portion). It is important to recognize that the revenue requirement utilized is an annual revenue requirement for the First SoBRA, even though the First SoBRA will not begin until September 2018. Using the annual revenue requirement, then utilizing 12-month total billing determinants (energy and demand) as the divisor, results in appropriate rates for use in the four remaining months of 2018 during which these rates will be applied to bills.

Q. Does the 2017 Agreement provide for a true-up mechanism to be applied to SoBRA rates?

A. Yes. The 2017 Agreement provides that each SoBRA tranche will be subject to a true-up for the actual cost of the approved project. Once the difference between the estimated and actual costs is known, the true-up amount will be included in the Capacity Cost Recovery Clause rates, with interest applied. In this docket applying to the first tranche, there is no true-up to calculate.

Proposed Rates and Tariffs for SoBRA

Q. Having completed the allocation of the first SoBRA revenue requirement to rate classes, what is the next step to derive the base rate adjustment?

A. Using the methodology called for in the 2017 Agreement described above, certain rates in each rate class were increased to recover the identified revenue requirement.

Q. Do you have exhibits that show the results of that base rate adjustment design?

A. Yes. Revised Document No. 2 of my exhibit was prepared for that purpose. It uses the E-13c MFR schedule to show the rate changes proposed to recover the SoBRA class revenue requirements by rate and rate schedule. Revised Document No. 3 of my exhibit rolls up the rate schedule amounts to rate class using the E-13a MFR schedule, which then can be compared to Revised Document No. 1 of my exhibit to show how close the rate design comes to collecting the allocated revenue requirements. Finally, Revised Document No. 4 of my exhibit utilizes the A-2 MFR schedule to show the impact of the SoBRA increase on typical RS, GS, GSD and IS bills. This presentation shows only the SoBRA impact since the fuel benefit and impact of the increased CCV and standby generator credits are already included in the present bill calculation through the 2018 Fuel and Conservation Clause rates utilized.

Q. Please explain the fuel impact of the First SoBRA and how that affects rates in 2018.

A. The first tranche of solar generation that will begin service September 1, 2018 is expected to provide fuel savings of approximately $3.3 million during the remainder of 2018. Those expected fuel savings were included in the 2018 annual fuel cost recovery factors approved by the Commission on October 25, 2017, so the approved fuel factors utilized in the bill comparisons are already lower, for the entire year, as a result of the first tranche of SoBRA solar generation in the 2017 Agreement. The savings represent a $0.17 reduction on the 2018 residential customer 1,000 kWh monthly bill.

Q. Do you have an exhibit that shows the redlined changes to tariff sheets affected by implementation of the First SoBRA?

A. Yes. Revised Document No. 5 of my exhibit was prepared for that purpose.

Q. Do you have an exhibit that shows the clean tariff sheets affected by implementation of the First SoBRA?

A. Yes. Revised Document No. 6 of my exhibit was prepared for that purpose.

Summary

Q. Please summarize your direct testimony.

A. I have performed the cost of service and rate design components of the First SoBRA in accordance with the provisions of the 2017 Agreement. I have also performed rate class allocations and determined the appropriate base rate increases by rate class needed to recover the First SoBRA revenue requirement. The proposed fuel savings and residential customer bill impacts are as shown in my revised direct testimony. The revised modified tariff sheets that accompany my direct testimony properly implement the First SoBRA rate adjustments and should be approved by the Commission.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BY MR. BEASLEY:

Q Mr. Ashburn, did you also prepare and cause to be filed with your revised direct testimony revised exhibit marked WRA-1 consisting of six documents, and identified as Exhibit No. 4 in the comprehensive exhibit list?

A Yes.

MR. BEASLEY: Mr. Chairman, I believe that item has been inserted into the record as Exhibit 4.

CHAIRMAN GRAHAM: Duly noted.

MR. BEASLEY: Thank you.

BY MR. BEASLEY:

Q Mr. Ashburn, would you please summarize your prepared direct testimony?

A Yes.

Good afternoon, Commissioners. The purpose of my prepared revised direct testimony is to describe the provisions in the 2017 agreement recently approved by the Commission that govern the cost of service and rate design for a solar base rate adjustment, a SoBRA, and to sponsor and explain the proposed rates and tariffs for the company's first SoBRA effective September of this year.

I performed the cost of service and rate design components of the first SoBRA in accordance with the provisions of the 2017 agreement.

I performed rate class allocations and determined the appropriate base rate increases by rate class needed to recover the first SoBRA revenue requirement.

The proposed fuel savings and residential customer bill impacts are as shown in my revised direct testimony and revised exhibit. The revised direct testimony and exhibit were revised to reflect the reduced revenue requirement for the first SoBRA resulting from application of the impact of tax reform on that revenue requirement. As part of that revised exhibit, Document No. 4 shows typical bills for the rate schedules and the impact on a typical bill of the first SoBRA.

For example, for 1,000 kilowatt hour residential bill, it shows a 1.7 percent increase. It should be recognized, however, that an annualized fuel impact for that first SoBRA has already been reflected into the fuel rate used in both the present and proposed rate calculations, and thus, that benefit is not represented in the 1.7 percent increase.

That annualized fuel benefit is only for four months usage in 2018 of the first SoBRA. And that rate impact and benefit will be increased in 2019, when a full year of the first SoBRA has been in service.

The modified tariff sheets of the company in my direct testimony properly implement the first SoBRA rate adjustments and should be approved by the Commission.

That concludes my summary.

Q Thank you.

MR. BEASLEY: Mr. Chairman, we tender Mr. Ashburn for cross-examination.

CHAIRMAN GRAHAM: Okay. Mr. Rehwinkel.

MR. REHWINKEL: Thank you, Mr. Chairman.

EXAMINATION

BY MR. REHWINKEL:

Q Good afternoon, almost evening --

A Almost.

Q -- but I just have a few questions to ask you about true-ups.

If you have -- do you have a copy of the agreement with you, or what's Exhibit 15?

A I have exhibit 15, if that's the one you are using.

Q Yes.

A Yeah.

Q Let's look at page 11, and a little more than

a third of the way down, or maybe about a third of the way down, there is a sentence that starts the rate change in in-service dates --

A I see it.

Q -- do you see that?

It says: The rate change in in-service dates specified in the chart in subparagraph 6(g) are no sooner than dates, and the SoBRA rate changes for each tranche will be implemented effective on the earliest in-service date for that tranche identified in such chart, and subsequently trued up to reflect and correct for, one, any delay in the actual in-service dates of any of the projects in a particular tranche beyond the applicable in-service date for that truth. And, two, the extent to which the actual installed costs of any project or projects vary from the projected costs used to set the SoBRA rate change but may not exceed the maximum incremental annualized SoBRA revenue requirement or maximum cumulative annualized SoBRA revenue requirement set forth in subparagraph 6(g), or the installed cost cap set forth in paragraph 6(d).

Did I read that right?

A You did.

Q Okay. Is it your understanding that those are the only two circumstances under which true-ups will

occur?

A For the base rate part of the SoBRA, yes. That's correct.

Q Okay. What other part --

A Well, fuel. I mean, we projected what the fuel impact will be of the SoBRA when it starts in September, so there will be what the actual is, what will affect through the fuel clause, but that's also associated with Tranche One.

Q Okay. So you heard me ask, I think it was Mr. Ward, about the first tranche going into effect, and if it goes into effect -- well, first of all, in your projection for fuel, you have assumed a one -- a 9/1/18 in-service date, is that correct?

A That's correct.

Q If for whatever reason it goes into affect two weeks earlier and you can't increase base rates, but you are going to achieve a fuel savings the instant you turn that on, right?

A That's correct. And the actual fuel benefit will be then reflected back to the fuel clause through true-up mechanisms in that.

Q Okay. So the true-up in fuel will be based on in-service date and actual fuel savings that you --

A Yeah, performance of the unit compared to the other --

Q Okay.

A -- part of the fleet, yes.

Q Now, back to the base rate true-up. If hypothetically, the first tranche goes into affect October 1st, there would be a true-up for that at some point in '19, right?

A Right.

Q And if the costs are $10 lower for each project, then there will be a true-up for that; is that right?

A That's correct.

Q Okay. Now, and I -- I don't nope the exact numbers, but the revenue requirement that Mr. Rocha calculated is 24,245,000, and the -- so you would roughly project about $8 million, and I know that every month varies, right?

A Right.

Q But there would be a projection of about $8 million of revenue to be recovered from the first tranche in the months of 2018, right?

A Right.

Q If weather is such that you actually recover $10 million because you have more billing units, there would not be a true-up for that; is that right?

A That's correct. We would go back and revise the revenue requirement to reflect those two factors we talked about, then apply the same billing determinants that I used to come up with the SoBRA Tranche One rates. So there would be an adjustment in the base rate part, but not reflecting actual performance, except for the fuel.

Q Right. And likewise, if you only recover $6 million because you have really, really mild Chamber of Commerce weather in the last four months of the year, there would not be a true-up --

A That's correct.

Q -- for under-recovery?

A That's correct.

Q Okay. And just one more true-up calculation. We talked about the actual costs. There would be a true-up for that, and the incentive that's calculated based on actual cost is a part of that true-up. In other words, if you are projecting 1,324 and you come in at 1,306 for the Payne Creek project, that would be trued up, correct?

A The incentive mechanism would be recalculated based on what the revised numbers are.

Q Okay. All right. And then one final question, just so we are clear on what we are doing

here. I know we talked a little bit about fuel, and that's in a separate docket, right?

A Uh-huh.

Q Any true-up that occurs, how will that be returned to the customers? Let's say that there is $1 million credit based on the in-service date and the actual costs that you calculate for 2018, how would the customers get that credit back?

A Well, there is two -- there is two ways the true-up affects the customers. One is that we would be recalculating the SoBRA 1 rate, which is affecting them going forward from a certain date, whenever that date is that a true-up occurs.

Then there is the period of time when SoBRA 1 has gone into service, at which point we now change the rate to reflect the revised costs. There will be that true-up period, and we will calculate that and recover -- I believe it goes back to the conservation clause or the capacity clause, one -- I forget which one.

Q Okay.

A But it goes back through the clause, so the ratepayers will accrue that benefit, or if it's the other we, right, the shift could go the other way, it could be a recovery from them.

Q Right. Okay. So regardless of how those monies are trued up, we are still here today in a base rate recovery clause, this is not a clause proceeding, right?

A That's correct.

MR. REHWINKEL: Okay. That's all I have. Thank you, Mr. Chairman.

CHAIRMAN GRAHAM: Mr. Moyle.

MR. MOYLE: Thank you.

EXAMINATION

BY MR. MOYLE:

Q Good afternoon, Bill. I just have a few questions for you.

Are you familiar with the other SoBRA agreements that have entered into by Duke and Florida Power & Light?

A Somewhat, not in great detail, but somewhat.

Q Do you know that they have a similar true-up provision?

A I don't really know with that part.

Q Okay. When are customers going to see the revenue requirements show up in their bills related to this SoBRA, assuming the Commission approves your petition?

A So we've been talking a lot about September 1, and that's what everyone has talked about, but really what it talks about is the first billing cycle of September. It just so happens the first billing cycle of September is September 4th this year, because that -- the billings calendar changes slightly dependent on if a day is on a holiday, or it's a weekend, or something like that. So the first billing cycle is September 4th. That's the first bill that will reflect a SoBRA rate in it.

Q Okay. And if all of a sudden we have a horrible summer weather-wise and you are not this -- these solar units don't come on-line until November, people will still see a bill increase on September 4, is that right -- or no? I am trying to understand the true-up mechanism that you are talking about --

A Yeah.

Q -- and whether this is a hardwired thing, yes, you are going to get your bill in September --

A Right.

Q -- and it's going to be up, or is it you got to have the unit commercial and you say, the unit is commercial, and then letting the bills flow. I am not sure I understand how that's going to work.

A So there is a couple of things in there, so I can't do a yes or no to start.

First, you know, Mr. Ward promised me a needle point landing, right, on September 1, and I have just given him a little more runway to land on, until the fourth. My understanding, I believe in the agreement it says that if the units are not running, we can't start billing people for them. So if for whatever reason, you know, something cataclysmic occurs like you are suggesting, or they are not running, we are not going to get started on billing people until they are up and running. So, like, as OPC was saying, if it's all the way into October or something, we won't get it started until then.

Q Okay. And will you be keeping the Commission or the intervenors informed with respect to how the project is going and when to expect these increased bills?

A We can certainly -- I am sure the company can make you aware. I mean, I am not sure I am the one. Mark will know when it's coming in for landing, and I am sure we can communicate that in some manner.

Q And would you just briefly -- I think you had answered a question from Mr. Rehwinkel that the residential rates were 1.7, but could you just let the Commission and everyone know what the anticipated increase is for residential, for commercial, and just

maybe use GSD, and then for industrial, non-standby?

A Well, in my exhibit in, Document No. 4, there is four pages there which have what's called typical bills. These are -- this is an MFR form that we use when we file rate cases, and so it's got them listed for identification Tranche One in the present and proposed for residential, and then for GS, and then for GSD and then for interruptible IS.

So these show the bill under present rates and proposed rates, the increased percentages, and the amount the increase on the bill, and it has it for various kilowatt hour levels. So for example, the 1.7 you were describing is a number based on 1,000 kilowatt hour bill; which in the residential one, which is on page one of four of my Document No. 4, is on line 11, and you can see up to the right, it's a 1.7 percent increase, but as you change consumption, the percentages are different.

So because of the fuel benefits, and so forth, as you go down and use less and less energy, it's less of an increase. You see it's a smaller percentage as you go down in consumption every month. As you go up in consumption a month, it starts going down again, because again, you get to the fuel benefit as well.

So it's sort of right around that point around the 750 to 1,000, it's the high point on the percentage increase. If you go to the next age page, you have GS, very comparable, the bill amounts are very close, and so you see the same sort of difference for consumption.

GSD shows same sort of presentation, but it shows it in a different manner. It shows different size kW loads for the customers, 75, 500 and 2,000, and then it shows it at different kilowatt hour consumptions, so that's different load factors. This is the way reports are normally produced.

And you can see that as the energy consumption for kW goes up, the percentage increase goes down, and that's because the SoBRA recovery is through the demand charge, and we have increased the demand charge, so we stick with recovery through just the demand charge, but as energy consumption goes on you get a fuel benefit, but I don't have an increase in your energy charge. So that's the GSD, and IS is very similar in the presentation as well.

Does that help?

Q It does, thank you -- thank you for that.

This is somewhat related, but have you ever considered whether there is an average commercial load that could be used that is equivalent or on par with the 1,000 kilowatt load that you always hear residential? I

mean, years and years I have heard everybody say, well, the average residential, 1,000 kilowatts, but there is not a comparable use of something for people that are commercial or industrial, and I was just wondering if you have ever given any thought to saying, well, what might that be, because there are a lot of businesses in Florida, and they are eager to know what are we looking at, so I just was wondering if you had given any thought to that?

A We have over many decades to be honest with you. The residential one produces -- often what is published in the papers with rate cases and other things is 1,000 kilowatt hours bill. I think that's just because it's a nice round number to use. In fact, most of our average residential use is somewhat like more 1,200 or so, but that's not a number people, you know, rolls off the tongue very easily. So everyone uses 1,000.

When you get into the GS and GSD classes, there is enormous range. It's not typical. You -- in GS, for example, you have everything from a guard shack up to a convenience store, to a strip center, place for a real estate agent. It's just all over the place. You have load factors between one percent and 80 percent, and we put pumps on the GS rates. So the range is just so varied, it's hard to suggest there is an average, or a typical GS customer.

GSD is really a little different in that it's almost by industry, right? You can look at school systems, they typically have a typical 60 percent load factor, or, you know, so much size for a high school and so forth, but that's different than a manufacturing facility that's large enough or something like that. So it's just difficult to come up with a typical.

What we do is we use these ranges. We show different demands, 75, 500, 2,000, that kind of thing, to show ranges of size, and then ranges of load factors, and that way we can explain to customers who call, hey, this is what I am using, or you can look on their system -- our system and see what their load factors are and what their size is, and give them some good guidance based on that.

Q Thank you. I appreciate it.

MR. MOYLE: That's all I have.

CHAIRMAN GRAHAM: Staff.

MR. TRIERWEILER: No questions from for this witness.

CHAIRMAN GRAHAM: Commissioners.

Commissioner Clark.

COMMISSIONER CLARK: I would just echo Mr.

Moyle's comment. I think you are absolutely right on target in terms of classifications.

One of the things you will see the utility companies know that 1,000 standard kilowatt hour, and you even see the inclining block rates, where do inclining block rates begin at? 1,000 kilowatt incrementals. Anytime we look at those, you will always see them beginning at that point after what we quote as the price for 1,000 kilowatt hours. I just wanted to comment. I agree with your comment there 100 percent.

CHAIRMAN GRAHAM: Redirect?

MR. BEASLEY: Thank you, Mr. Chairman. Very briefly.

FURTHER EXAMINATION

BY MR. BEASLEY:

Q Mr. Ashburn, you were asked questions about the effective of a delay in the actual in-service date after project and the impact of that. Could you take a look at paragraph 11 -- or excuse me, page 11 of the 2017 agreement?

A Yes.

Q There is a parenthetical there in the middle of the page there, parenthesis one, do you see that?

A I am sorry, where is it at?

Q Okay, this is on -- what paragraph -- it's order number -- excuse me, the order is on page 18, and it's page 11 at the bottom, but if you look at the top, it says page 18.

A Yes, I got that page.

Q Okay. In the center of that page, that provision of the agreement addresses delay in the actual in-service date. Could you take a look at that and see if that influences your answer to that earlier question about the impact of the delay in the in-service date?

A If any delay in the actual in-service date of any projects beyond the applicable in-service date for that tranche, right?

Q Right.

A Is that what you are pointing to?

Q Yes.

A Yes. I am not sure what you are asking me.

Q That would govern any effect of a delay in the in-service date, would it not?

A Yes.

Q Thank you.

One other clarifying question is what is the status of Tampa Electric currently, a summer peaking system or a winter peaking system?

A Well, that's a debate that rages, and is probably going to continue to change. We have been a winter peaking system since I have been there back in the early '80s, and that was mostly during the cold weather. People who live in Tampa know sometimes we get cold front make it all the way down here. You get a cold front in Tallahassee every year for some period of time. Sometimes it makes it to Tampa, and when it does, and we have temperatures in the 30s it just throws our peak all the way you up because we have very little gas heat and everything is strip heat, the heat pumps come on and then suddenly our peak goes through the roof.

We go through winters where we don't have a cold weather snap. It just doesn't happen. And we've even gone through a whole winter before that have no heating degree days, if you know what those are. In those years, we don't see a winter peak, but we still plan for a winter peak. When we do our planning, Mr. Rocha will tell you, the resource people and the forecast people assume some sort of a winter will happen.

Meanwhile, what we really look at is these are very needle peak type things, they happen for a morning, a day, you know, very rarely it goes over more than a couple of days. But the summer, from about June through October, is hot virtually every day, way into the 90s.

And so we have a sustained peak that may not exceed the winter peak, but it is sustained, and you really have to build your system, your units to run that kind of long period of time.

So as you start adding solar, and we are now about to add 600 megawatts of solar over the next few years, solar, of course, works with the sun. And when your winter peak is in the morning in a winter day, it's dark, and so there is no solar capacity benefit at all for a really cold morning in the winter.

However, as Jim was talking, during the summer, it's cranking along pretty well during days when it's hot; particularly when it's hot and we have high loads, it's a little less rain, a little less cloud, and so it's producing a benefit.

As you start adding more and more solar, you start pushing the summer peak down a little bit because it's serving that peak with what essentially, as he said, is must run units. And so now we are worried more about the winter peak than we are worried about the summer peak.

And so that's things that you probably read about, the duck curve, and you are starting to see some things in California and other states where they are starting to suggest that on-peak period are really in the late afternoon, and middle of the day is an off-peak period, because you have so much solar being produced in some of these states that you start having free solar, and you really got to encourage people to use it in the middle of the day, otherwise it's wasted.

So there is a lot of change coming in the next few years about that, and I think it actually supports -- the Commission has over, a lot of years, since I have been there, worked on a 12 coincident peak allocation methodology, which we used in this proposal, which you approved, because all the months start matter. The winter peaks matter. The summer peaks matter, and the spring and fall matter as the units go down for maintenance and so forth.

So I don't know if that answers your question, but that's kind of a change that's coming in the next few years about coincident peaks, and what we are building for.

Q Thank you.

MR. BEASLEY: No further questions.

CHAIRMAN GRAHAM: Thank you, Mr. Beasley.

Exhibits are already in.

MR. BEASLEY: I ask that the witness be excused.

CHAIRMAN GRAHAM: Yes.

MR. BEASLEY: Thank you.

MR. WILLIAMS: Mr. Ashburn, thank you for your testimony today.

THE WITNESS: Thank you.

(Witness excused.)

CHAIRMAN GRAHAM: All right. Mr. Rehwinkel, you requested a five- or 10-minute break?

MR. REHWINKEL: Mr. Chairman, I think five minutes would give me enough time to consult with Mr. Kelly and Mr. Willis and make the determination that we need to make to give the Commission an answer that we committed to give you in our opening.

CHAIRMAN GRAHAM: Okay. Let's take a five-minute break, which will be, by that clock back there, 10 after 5:00.

(Brief recess.)

CHAIRMAN GRAHAM: OPC, you have the floor.

MR. REHWINKEL: Thank you, Mr. Chairman. And thank you for the opportunity to consult. I am prepared to make a closing at this point.

CHAIRMAN GRAHAM: Sure.

MR. REHWINKEL: Commissioners, the Public Counsel normally does not take a position in support of a rate increase. At the start of this hearing, I referred to the agreement that you are here to implement today, and I mentioned that we believe it is in the public interest. After what we heard today, we still believe that the agreement is in the public interest.

When the Public Counsel and the other parties signed the agreement with Tampa Electric, we achieved a significant benefit with a four-year base rate freeze and the opportunity to have quick return of tax savings to the customers.

At the time the agreement was signed we understood the magnitude and the ramifications of a solar base rate increase and the significant fuel savings potential of such a rate increase and project.

We and the other parties asked for this hearing today, and we think it was important that we had the hearing on TECO's first SoBRA, and we appreciate the staff's and the Commission's work to make sure that this hearing occurred. We believe it was important for the proposal of the company to be tested against the requirements of the agreement, especially the incentive provisions in the agreement.

The incentive mechanism is a value, and I think you heard testimony today that indicates that there was a tangible value to that incentive to bring lower cost to customers assuming that the actual costs are near or at or hopefully even below the projected costs.

The Public Counsel, must say, however, that we are disappointed that the Baum Road land costs have the appearance of being excessive. We acknowledge that the Baum Road project is, nevertheless, under the cap that we agreed to. We accept the explanation that the company provided that led to this cost. However, we believe the no safe harbor and no-build to provision that's in the agreement must be meaningful. In future SoBRA determinations by this commission, we hope that the Commission takes a close look and holds the company to the burden that it has, especially under this provision of the agreement.

And I am going to say something that's a little bit outside of the record, but I feel obligated to say this, is that when we were negotiating this agreement, we were aware of the average land cost figure that Mr. Ward mentioned in his testimony, and so that number is not something that surprised us. Nevertheless, on a project-by-project basis, where the customers are paying rates, we think it's important that the Commission take a close look at these costs.

Having said this, we believe that, on balance, it is -- the Office of the Public Counsel can take the position that the Commission that we would not seek to file briefs in this case, and we would not object to the Commission making a bench decision on the proposal that the company put forward in this case.

Thank you.

CHAIRMAN GRAHAM: Thank you.

Mr. Moyle.

MR. MOYLE: Thank you. I will make some comments, if I could, Mr. Chair.

I think I said -- as I said at the outset, my client is not a huge fan of the SoBRA mechanism, and we have argued against it in the FPL case on the grounds that it was not needed, and it was not cost-effective, and, you know, we have pretty strong feelings, you know, on that point. I juxtapose that with a deal is a deal, and we signed the deal, and we will live by the deal. It was negotiated and, you know, want to honor that.

The agreement allows us to ask questions related to certain provisions in the agreement, cost-effectiveness, and we asked some of those questions. We, I think, will continue to, when these SoBRA matters come up, participate and ask questions, and depending on the facts and the evidence, continue to make arguments given my client's position.

I asked a lot of questions, some designed to elicit some policy discussion, because I do potentially see this as an area that might be appropriate for the Commission to engage in rule-making on because it is a policy issue. Three utilities have this, and it's pretty complicated. There are a whole host of questions that are raised. Some of the provisions are the same, some are different, and we want to honor the agreement, but it's hard to know where things go in the future. So, you know, like the idea of the incentive mechanism. Does that make sense? Does it not make sense?

So anyway, I appreciate the time and the attention. I -- as Mr. Kelly and Mr. Rehwinkel said, we had our chance to ask questions, and we got some good information, and the statute provides us with the right to file a post-hearing brief, which you would then have to have staff consider and write a recommendation, and consider this at your Agenda Conference process, but we are willing to waive the right to file a brief, and would do so if the Commission does not believe that they need further information.

If you all are comfortable making a bench decision, we are not going to stand in the way. If you all say, we would like a brief on certain issues, we are happy to comply with that request.

CHAIRMAN GRAHAM: Thank you.

TECO, any comments before we hear a recommendation?

MR. WAHLEN: Just that we believe that we have clearly met our burdens of proof and the SoBRA should approved. We are not -- don't need a brief.

CHAIRMAN GRAHAM: Thank you.

Staff.

Little.

MS. MTENGA: Good evening, Commissioners, Moniaishi Mtenga with Commission staff.

TECO's filed its petition for the 2018 SoBRA projects pursuant to its 2017 petition for limited proceeding to approve the 2017 amended and restated stipulation and settlement agreement.

The 2018 SoBRA projects, also known as Tranche One, consists of the Balm Solar and Payne Creek solar projects. The review of these projects are subject to conditions that are included in paragraph six of the 2017 agreement. The projects are cost-effective and the projected default under the $1,500 per kilowatt AC installed cost cap as required by subparagraph 6(d) and 6(g) of the 2017 agreement.

The revenue requirement using the installed cap is projected to be 24.25 million with 385,000 attributed to the sharing mechanism.

Staff believes TECO has fulfilled the requirements set forth in the 2017 agreement regarding the 201 SoBRA projects. Staff recommends approval of this petition and is available to answer any of your questions.

CHAIRMAN GRAHAM: Thank you, staff.

Commissioners, any questions of staff or the applicant?

I will entertain a motion. Commissioner Brown.

COMMISSIONER BROWN: Well, first off I do want to say that I appreciate this hearing. I think it elucidated a lot of the details on the solar projects, and provides more clarity on how, in practice, the SoBRA mechanism and recovery will be collected moving forward.

That being said, we talked about earlier today at the Agenda Conference fuel diversity in one of our dockets, and I have to say that with these two projects, in addition to the 600 megawatts of solar, this is definitely transforming TECO's solar imprint.

It's exciting to see. I think the company clearly met the cost-effectiveness test that was laid out in the settlement agreement, and I am excited for the customers, and I am excited for the utility, and want to thank the parties for their foresight when you all negotiated the solar aspect in the settlement agreement, because it definitely provides several protections to customers, including the strict cost-effective test, the incentive mechanism and the true-up. So thank you all for your participation in it.

And with that, I would a move approval of the petition.

CHAIRMAN GRAHAM: It's been moved and seconded the approval of the petition.

Any further discussion?

Commissioner Polmann.

COMMISSIONER POLMANN: Thank you, Mr. Chairman.

I would simply support and echo Commissioner Brown's comments, and I would support moving forward.

Thank you.

CHAIRMAN GRAHAM: Any further discussion?

Seeing none, all in favor, say aye.

(Chorus of ayes.)

CHAIRMAN GRAHAM: Any opposed?

(No response.)

CHAIRMAN GRAHAM: By your action, you have approved the petition.

Gentlemen, thank you very much.

Staff, thank you, as always, for your help.

And that all being said, we are adjourned.

(Whereupon, the proceedings concluded at 5:25 p.m.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, DEBRA KRICK, Court Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 17th day of May, 2018.

____
DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #GG015952
EXPIRES JULY 27, 2020