BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20170210-EI

PETITION FOR LIMITED PROCEEDING TO APPROVE 2017 AMENDED AND RESTATED STIPULATION AND SETTLEMENT AGREEMENT, BY TAMPA ELECTRIC COMPANY.
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PROCEEDINGS: INFORMAL MEETING

STAFF PARTICIPATING: SUZANNE BROWNLESS
BILL McNULTY
GREG SHAFER
CURT MOURING
PHILLIP ELLIS
ELISABETH DRAPER
JUDY HARLOW
CHRIS RICHARDS
MICHAEL BARRETT

DATE: Wednesday, October 4, 2017

TIME: Commenced at 1:30 p.m.
Concluded at 2:32 p.m.

PLACE: Gerald L. Gunter Building
Room 105
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

REPORTED BY: LINDA BOLES, CRR, RPR
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APPEARANCES:

CARLOS ALDAZABAL, Tampa Electric
JEFF WAHLEN, Tampa Electric
BILL ASHBURN, Tampa Electric
JIM BEASLEY, Tampa Electric
J. R. KELLY, OPC
CHARLES REHWINKEL, OPC
ERIK SAYLER, OPC
MARSHALL WILLIS, OPC
JON MOYLE, FIPUG
ROBERT SCHEFFEL WRIGHT, FRF
KEN WISEMAN, Central Florida Hospital Alliance
DREW JERNIGAN, FEA

P R O C E E D I N G S

**MS. BROWNLESS:** Okay. Hi, everybody. Nice to see you. This is an informal meeting in Docket No. 20170210, the petition for a limited proceeding to approve 2017 Amended and Restated Stipulation and Settlement Agreement by Tampa Electric Company.

I want to start out by welcoming everybody and saying that we're going to go around and let everyone who's at the table identify themselves, and then we'll, by party, get everybody on the conference call to identify themselves.

So I'll start. Suzanne Brownless, staff at the Public Service Commission.

Mr. Moyle.

**MR. MOYLE:** Jon Moyle, representing FIPUG.

**MR. ALDAZABAL:** Carlos Aldazabal representing Tampa Electric.

**MR. WAHLEN:** Jeff Wahlen, Ausley, McMullen law firm, on behalf of Tampa Electric.

**MR. ASHBURN:** Bill Ashburn from Tampa Electric.

**MR. BEASLEY:** Jim Beasley, Ausley, McMullen, for Tampa Electric.

**MR. SAYLER:** Erik Sayler, Office of Public Counsel.

**MR. KELLY:** J.R. Kelly, OPC.

**MR. REHWINKEL:** Charles Rehwinkel, OPC.

**MR. WILLIS:** Marshall Willis, OPC.

**MR. MOURING:** Curt Mouring, Commission staff.

**MR. SHAFER:** Greg Shafer, Commission staff.

**MR. McNULTY:** Bill McNulty, Commission staff.

**MS. BROWNLESS:** Thank you. And for the folks that are on the phone, as I call out the name of your party or company, please identify yourself.

Do we have anybody on the phone from TECO?

**MR. WAHLEN:** All here.

**MS. BROWNLESS:** Okay. Thank you.

Anybody on the phone from OPC who's not here with us?

(No response.)

Anybody on the phone from FIPUG who's not here with us?

**MR. MOYLE:** I don't believe so, but if they are, they're free to identify themselves.

**MS. BROWNLESS:** Anybody on the phone from the FRF, Schef Wright. Schef, are you there?

(No response.)

Okay. Is there anybody on the phone from the West Central Florida Hospital Association?

**MR. WISEMAN:** Yes, Ken Wiseman.

**MS. BROWNLESS:** Hey, Ken. How are you today?

**MR. WISEMAN:** Good. How are you?

**MS. BROWNLESS:** Fine, thank you.

Anybody on the phone from the Federal Executive Agencies?

**MR. JERNIGAN:** Yes, Drew Jernigan.

**MS. BROWNLESS:** Hey, Drew.

**MR. JERNIGAN:** Hi. How are you?

**MS. BROWNLESS:** Fine, thank you.

Anybody on the phone from SACE?

(No response.)

Anybody on the phone from the Sierra Club?

(No response.)

Is there anybody on the phone who I have not identified a party for who would like to enter an appearance at this time?

(No response.)

Okay. Thank you.

And we have one new person with us, so, Schef, if you would like to identify yourself for the record, that would be great.

**MR. WRIGHT:** You bet. Schef Wright on behalf of the Florida Retail Federation.

**MS. BROWNLESS:** Thank you.

Okay. What we're going to do next is -- I'm sure you all have received TECO's slide presentation, and it's also been filed in the docket. So we'll go ahead and let TECO present their slide presentation.

**MR. WAHLEN:** Okay. Thank you, Suzanne. We really appreciate -- this is Jeff Wahlen, for those of you on the phone -- the opportunity to meet with everyone today, and appreciate all of the people who helped on this agreement and signed it, and we appreciate you getting together with us real quickly on this. It is important.

Carlos and Bill are going to explain the agreement with this, but I understand that if any of the Intervenors or, you know, consumer parties have clarifications, they may just jump in. And we have copies of the PowerPoint and the bullet points and also some rate impact sheets that Bill Ashburn is going to discuss here for anybody who wants them.

And I guess the last thing is we went to school on the Duke deal, and if anything in the transcript looks like it needs to be clarified when it's all over, we'd like to have an opportunity to do that. Hopefully we won't need to, but --

**MS. BROWNLESS:** Sure. Happy to do it.

**MR. WAHLEN:** Super. With that, I'll turn it over to Carlos.

**MR. ALDAZABAL:** Okay. This is Carlos Aldazabal, for everyone on the phone. First, I'd echo Jeff's comments. Firmly appreciate you guys taking the time to meet with us this morning.

This is a pretty simple agreement, but it did take a substantial amount of time from all the consumer parties to reach agreement. We believe that when you consider the deal in its entirety, it's something that's good for our customers.

As we go through the presentation, if you have any questions, by all means, just ask your question. It's probably better that way than waiting until the end of the presentation.

And with that, I'll kind of get started. As you probably notice, we have the same parties from the 2013 rate case settlement. We have the OPC; FIPUG; Florida Retail Federation; West Central Florida Hospital, and I apologize, I have Association but it is the Alliance; and the Federal Executive Agencies all signed up for this agreement.

We actually engaged OPC sometime late last year as part of this discussion process, and then we started engaging with the other parties around the March, April time frame.

We've also been in communication with the two environmental groups on that -- listed there. SACE actually provided a quote in our press release in support of the agreement, and Sierra Club was going to issue their own comments in support of the settlement.

So the provisions of the settlement, first is the term. We continue our existing stay-out through 2021. So that's another four years from where our current settlement was ending at the end of this year. Now it goes all the way through 2021.

The SoBRA provision, everyone here is pretty aware of what that is. We reached an agreement that includes essentially three different SoBRAs actually and the potential for a fourth SoBRA. If the first two tranches come in below 1,475 per KW, we would get to build that last 50.

The megawatt amounts in our deal are 150 megawatts, which would start September 1st of 2018; another 250 megawatts, plus or minus, or actually plus 2 percent variance, so it could be up to 255 megawatts starting January 1 of 2019; 150 megawatts in January 1 of 2020; and then the 50 optional megawatts would start January 1st of 2021.

The associated revenue requirements with those megawatts are reflected in page 10 of the agreement. Those revenue requirements that we have are based on

1,500 per KW in the, in the settlement agreement.

There's also a cost-effective requirement per tranche that's required as part of the settlement agreement, and what that means is that we must produce the energy at a cumulative present worth revenue requirement that's lower than compared to the analysis that we would do with -- without the SoBRAs, without those solar projects. And I'll give a little bit more information on that a little bit later on some of the follow-up slides.

The last component, of course, is the cost cap at 1,500 per KW. And just in laymen's terms, what that represents is if you're building a 75-megawatt project, you take the 75 megawatts, multiply that by a thousand, and then multiply it by 1,500. That's about 112.5 million, or actually 112.5 million. That's the cost cap that we can bill the project for. If it comes in above that cost, all we would be able to include in revenue requirements would be the 112.5 million, the revenue requirements associated with that dollar amount.

There's also a sharing mechanism, a sharing benefit mechanism, 75/25 split. So if the costs were to come in, for example, at 1,400, we would be able to include revenue requirements of 1,425 and recover costs on 1,425. 75 percent of the benefit goes back to customers, and the company retains 25 percent of that benefit.

That is the biggest provision in our agreement. I think there's about ten pages devoted to the SoBRA in our settlement, so I'll kind of stop right there for any questions that the group may have on the SoBRA itself. Great.

**MR. MOYLE:** We should make sure the record is clear that there are no questions.

**MR. WAHLEN:** Yet.

**MR. MOYLE:** Yet.

**MR. ALDAZABAL:** All right. Moving on, the next provision is moratorium on hedging and investments in gas reserves. That provision is one year longer than our stay-out, so it goes through 2022.

There's also a tax reform provision. That provision is modeled or very similar to the Duke Energy provision. The one exception is that any additional earnings that are generated as a result of a lower tax rate, we would not be able to utilize that to accelerate depreciation on any asset. Rather, that would be flowed back to customers through a one-time base rate reduction. That's the distinction between ours and Duke's on the tax reform provision.

There is a wholesale sales incentive

mechanism. It's essentially the same mechanism that we filed last year. That's still an open docket with the Commission with the exception that this mechanism has higher thresholds. The thresholds in the one that we filed were lower. These thresholds are set at 4.5 million. So any asset optimization that occurs up to 4.5 million, 100 percent of that benefit goes back to retail ratepayers. Between 4.5 million and 8 million, 60 percent is retained by the company, 40 percent goes back to consumers or ratepayers. And then anything above 8 million, if we were to cross that threshold, would be split 50/50.

The next provision I want to cover is on depreciation. There's a provision for depreciation that would allow us to, if we retired large assets, and the two examples I have listed here are Big Bend and AMR meters, starting with AMR, the company is moving forward with the replacement of AMR meters and transitioning to AMI meters. So we would continue depreciating the AMR meters that are being retired through their normal depreciable life.

We are evaluating the possibility of retiring Big Bend Units 1 and 2, and if that comes to fruition, we would continue the retirement of those assets through the term of the settlement, normal depreciation.

Some other provisions of the settlement, the ROE trigger would remain the same as what existed in the 2013 settlement. In fact, interest rates would also still remain the same from that 2013 settlement, so they weren't reset.

The equity ratio is 54 percent. We would use a 54 percent equity ratio for the SoBRA calculation, actual equity ratio for our earnings surveillance report reporting, and then we would be capped at 54 percent for clauses if we exited this agreement, or for calculating any interim rates if we were to somehow fall outside the ROE triggers. We would be capped at 54 percent. So if it's lower than 54 percent, we would utilize that equity ratio for those purposes.

We would use incremental sources of capital for the SoBRA calculation. We expect the incremental sources to be long-term debt, common equity, and the investment tax credits, but we could possibly utilize short-term debt. And if that's the case, that would also be included as part of the incremental source of the capital.

We have the same storm cost recovery provision from the 2013 settlement. So if the storm reserve is depleted down to zero, which we anticipate that is going to be the case as a result of Hurricane Irma, we would replenish that reserve. If it's over $100 million storm reserve cost, it would potentially be a period over a year. If it's under 100 million, the period would be over a 12-month period. We expect it to be below the 100 million threshold, so we expect it to be over a 12-month period.

We are increasing the standby generator program credit from 4.75 per month to 5.35, or 60 cents, and increasing the CCV credit, interruptible credit, from 9.98 to 10.23, or 25 cents. Both of those would commence in January of 2018.

I touched on the cost-effectiveness test. It is modeled after FPL's. And the way it works is our resource planning group would essentially model each tranche with the latest expansion plan, updating for the load forecast and the fuel forecast, and then determine if that tranche was cost-effective. So we would model the solar in the analysis and then model the same analysis without the solar. If it shows that it's beneficial for customers to build the solar, then we would move forward with that tranche.

As I mentioned, the first tranche is scheduled to go in service September 1st of next year. So assuming this agreement is approved by the Commission, and so the CASR is out on November 6th, we would follow that up shortly thereafter with a filing to approve the first tranche.

We would do a separate filing for cost-effectiveness on each subsequent tranche, and we would expect to follow those right around the same time as the fuel filings so we could include the fuel benefits starting in January on the solar.

**MS. BROWNLESS:** May I ask a question?

**MR. ALDAZABAL:** Sure.

**MS. BROWNLESS:** Why did you decide that you would make a separate filing as opposed to filing this in the fuel clause where the impact of this is --

**MR. WAHLEN:** That was something that was discussed extensively by the parties, and everybody agreed it ought to be a separate filing that would travel with the fuel filing.

**MR. REHWINKEL:** It was just a negotiated term. That's, that's all could I say about it, yeah.

**MS. BROWNLESS:** I'm just trying to think about the practical.

**MR. REHWINKEL:** Yeah. FPL's -- it's a, it's -- I think it's -- I look at it as a, as a hybrid between FPL and the Duke agreement. The FPL agreement allows a party to ask that it be taken out of fuel. Duke has it just running in the fuel, I thought. And this is just another variation. That's, that's how the negotiation shook out; that's how it went.

**MS. BROWNLESS:** But y'all would not be adverse, because there is going to be an effect in the fuel clause of this obviously, you would not be adverse to essentially working those together and having an issue in the fuel clause that dealt with a petition. Do you understand what I'm trying to get to?

**MR. WAHLEN:** I think each of the parties could talk for themselves, but Tampa Electric's interest was making sure that the fuel benefits of the solar, when it goes in service, would be synced up with the fuel clause. And if that's the mechanism for doing it, I don't think we would object to that. The other parties would -- I think as long as they have a chance in a separate hearing to, to challenge the, the number, I don't think they're going to object. But they can all speak for themselves.

**MR. ALDAZABAL:** To address your concerns, we could probably file these maybe a little bit before the fuel filings, so at least this would be in the record before the fuel filing. We wouldn't file it afterwards because obviously you make a decision on the fuel and that impacts this.

**MS. BROWNLESS:** But your projection testimony would include all this, of course.

**MR. ALDAZABAL:** Yes, yes.

**MR. MOYLE:** So I think, I think also that, you know, given what has been evolving with these solar adjustments, they are -- I mean, to the point TECO made earlier, it's, like, six pages of the settlement is related to SoBRA, and it's a lot of megawatts and it's a lot of dollars that are, that are flowing through. And I think having it as a separate proceeding provides some additional transparency for it and additional opportunity to understand exactly where things are and how they're moving. So it was, I mean, to echo what everybody else said --

**MS. BROWNLESS:** But you don't necessarily --

**MR. MOYLE:** -- it was negotiated, it was a negotiated provision of the agreement.

**MS. BROWNLESS:** And all I'm trying to figure out is --

**MR. WAHLEN:** How they come together.

**MS. BROWNLESS:** -- how they work together. You're not necessarily -- by, by having a separate filing, you're not necessarily taking the position that it ought to be something that's spun out as opposed to considered in whatever fuel clause docket gets entered.

**MR. REHWINKEL:** Suzanne, it's paragraph H on page 15. What is this? 6, 6H.

**MS. BROWNLESS:** Uh-huh.

**MR. REHWINKEL:** And kind of halfway down it says, "The parties further intend that the Commission action on the remaining SoBRAs," this is the ones that are filed, that are first of the year --

**MS. BROWNLESS:** Uh-huh.

**MR. REHWINKEL:** -- "shall be resolved, to the extent practicable, on a schedule that is contemporaneous with the annual regularly scheduled fuel and purchased power cost recovery docket hearings, provided, however, that the Commission, on its own initiative or upon good cause shown by any party to this 2017 agreement, or any other entity satisfying the standing requirements of Florida law, may set Tampa Electric's request for approval of any SoBRA or SoBRA tranche for a separate hearing to be held at any convenient time to permit timely resolution before the company's projected in-service date for the SoBRA tranche that is the subject of such petition or hearing."

The intent is that they be synced up, and I think the only way that could happen is they would have to be resolved some way in advance of when you set the factor.

**MR. MOYLE:** But to be clear, what we agreed to was a separate proceeding for the SoBRA.

**MR. REHWINKEL:** Yeah.

**MR. MOYLE:** Right. And Suzanne is asking, "Well, you have a separate proceeding for SoBRA," which, you know, I think they should all be separate, but, you know, that's one person's view. You're going to have an issue probably in the fuel docket that says given the results of SoBRA --

**MS. BROWNLESS:** And the appropriate adjustment be made to the --

**MR. MOYLE:** -- what adjustment should be made with respect to the fuel clause?

**MS. BROWNLESS:** Right.

**MR. MOYLE:** So if that's what we're talking about with respect to having that kind of True-Up Mechanism in the fuel --

**MS. BROWNLESS:** Yeah, we have to have something in there.

**MR. MOYLE:** Yeah, that makes all the sense in the world. But to the extent we're talking about mushing the SoBRA into the fuel docket, that would cause some concern.

**MR. ALDAZABAL:** One way of doing that is we could provide alternative schedules, one with and without the SoBRA in the fuel filing.

**MR. MOYLE:** But to be clear, I mean, we want the adjustment to be made in the fuel filing.

**MR. ALDAZABAL:** I understand.

**MS. BROWNLESS:** I mean, it --

**MR. MOYLE:** We just don't want the whole, the whole SoBRA thing to go in there because the fuel, fuel docket historically has been, you know, measured in, in -- I was going to say seconds, not minutes, but maybe say minutes, not hours.

**MS. BROWNLESS:** All right. Thank you. I just was trying to --

**MR. ELLIS:** Just as a follow-up of the cost-effectiveness test, so usually when we do a cost-effectiveness test, we'll have multiple scenarios and we'll kind of create a little matrix of the multiple ones.

This agreement seems to be more of kind of a yes or no, so that doesn't -- so in this it basically, from my understanding of the settlement and reading of it, you're looking at, say, the base case is cost-effective would be a proper way of looking at that, and then in this separate proceeding, parties could argue what goes into the base case. So avoided gas pipeline capacity, CO2, et cetera, things like that,

that would all be what is argued in this separate proceeding and in for a base case scenario. And people could argue that there and that's the intention, or am I incorrect?

**MR. ALDAZABAL:** Well, we were looking at it as, kind of looking at it as, like, a new power plant. So you have a base case and then you run that base case with and without that power plant. If it's cost-effective to include the solar as a generating unit with the new assumptions, with the new fuel forecast, new load forecast, and it shows that there's cumulative present worth revenue requirement benefits by having that in there, then it passes the test.

**MR. ELLIS:** But parties are still free to argue what goes into the base --

**MR. ALDAZABAL:** Yes.

**MR. ELLIS:** Okay.

**MR. ALDAZABAL:** Or the assumptions utilized in it, yes.

**MS. BROWNLESS:** Thank you.

**MR. ALDAZABAL:** The next slide is Bill Ashburn's rate design.

**MR. ASHBURN:** Okay. So the base revenue requirement for each SoBRA tranche will be allocated using the 12CP and 1/13th method for two classes for purposes of recovery with one difference, and that is that lighting will only recover 40 percent of their allocated revenue requirement based on the 12CP and 1/13th, and the other 60 percent of lighting would be recovered back from the other classes. So it's reallocated back to the others.

The rate design is fairly straightforward. Again, lighting will only get this 40 percent revenue requirement, and that's going to get recovered from their base energy charge. So the energy charge would get reflected, not the fixture charges. So they're all left alone.

Second, for any rate schedule that has a demand rate as a component of the SoBRA revenue requirement will be covered through an increase to the demand rates of those, those rate schedules only. But for a standby -- and, conversely, if you're a rate schedule and you only have an energy charge, you've got to get it from the energy charge. So it's coming from the energy charge from those customers.

For a standby rate schedule, and that would be like SBI and SBF type rate schedules, the SoBRA-based revenue requirement will not be recovered from the standby rate -- the standby demand charges in that schedule but will be from the supplemental demand charges in that schedule.

So you have two sets of demand charges in a standby rate, standby demand charges and supplemental demand charges. It'll be recovered from the supplemental but not from the standby demand. Okay? That's pretty much the rate design.

**MR. McNULTY:** Do you want to speak to the last page of the rate impact?

**MR. ASHBURN:** So we've run -- this is a set of tranches over a bunch of years, so what we mostly looked at was at the end when all 300 megawatts are in and what happens; right? So this is sort of the forecast as it goes up to the final numbers about what the rate impacts would be.

And we also have -- if you want to hand these out, Jim, what the rate impacts -- we did some schedules that look sort of like MFR type schedules that shows the typical bills and, and that kind of thing.

**MR. REHWINKEL:** You said 300. You mean 600.

**MR. ASHBURN:** 600, yes. And so this has the typical bills, and it shows the impact on the residential, GS, the GSD, and IS customers at the end. But this shows the increase as it goes along, including the impact on the fuel going down because the solar obviously has zero fuel costs and so, therefore, has a beneficial impact on the fuel rates.

The increase that Carlos talked about, the standby generator credit and the CCB credit, will be recovered through the conservation clause. So it is a very slight increase to the conservation clause after that finally works its way through the clause. So these, these reflect that at the end, the ones that I'm handing out, but this is showing the impact as it grows, as you add them up.

**MR. REHWINKEL:** And, Bill, the document you're looking at, in the upper left it says, "500," but that's a typo.

**MR. ASHBURN:** It meant 600. That's a typo.

**MR. McNULTY:** One question about this, this final slide is we see it go out to 2021. That is incorporating the forecast of units of --

**MR. ASHBURN:** Yes, all of our -- all of the forecasts are rates, even including in this final sheet. We don't have full forecasts out to '21, the billing determinants and all that kind of stuff. So, so what this reflects is 2017 billing determinants and 2017 clause rates and what the difference would be to those if you added more solar to it and that sort of thing.

**MR. McNULTY:** So presumably those latter years, 2020, 2021, the rate increases for a thousand kWh residential bill would -- expecting growth to happen would be lower.

**MR. ASHBURN:** Right, right. If there's growth, and we expect some growth, that -- this would be the highest it could be. It would probably be slightly less because of that. And also because the rate design has it in the demand rates based on only demand, it depends on your load factor, whether your load factor changes over that time, what the impact on the bill will be.

**MR. ALDAZABAL:** And it's also assuming a 1,500 per KW cost on the --

**MR. ASHBURN:** Right. It's also the max cost at the top of the cap of what we're building. So if we build it cheaper, then obviously it's going to be less as well.

**MR. ALDAZABAL:** The reason 2021 looks somewhat odd there on the first one for fuel, there's a capacity benefit associated with the solar. So we avoid incurring a capacity payment. It's around 66 cents, 66 cents in that last year, which is why you see that dropoff in 2021.

**MR. McNULTY:** And for the, for the residential rate impacts, it's incorporating exclusively the SoBRA, or are there other pieces, other things in there besides

SoBRA?

**MR. ASHBURN:** No, just the SoBRA impact, the fuel and the base rate increase, and a slight change in the conservation for the two credits going up.

**MR. McNULTY:** Okay. I have an even more basic question than that. If there are any other questions on rate impact.

If we go to the front page of -- the first page of the slide presentation, it talks -- it uses the term "TEC," T-E-C. Is -- what's the acronym that we're going by these days?

**MR. ASHBURN:** We have conference calls (phonetic) honestly about what to call ourselves. A lot of, a lot of people use TEC for Tampa Electric Company, and so that's what was meant here by whoever prepared this thing. But some people say TEC inside the company, and it just sort of makes its way into things. I try to make them say Tampa Electric everywhere, but it doesn't always make it. Sometimes it ends up with that.

**MR. McNULTY:** I noticed that Tampa Electric was spelled out throughout the settlement and the petition.

**MR. ASHBURN:** Right.

**MR. McNULTY:** There was no --

**MR. ASHBURN:** Right. We tried real hard to keep it there.

**MR. McNULTY:** If I could reference one -- the other document that appeared in the docket file yesterday, which was -- incorporated a bullet point summary of the agreement. And the second page of that references a residential rate impact -- the very last bullet references a residential rate impact per thousand kWh of a dollar. And I'm just wondering how that number sits down -- first of all, which year it references and how it sets down with what we saw as the last page of rate impacts that were presented in this, in this slide presentation.

**MR. ALDAZABAL:** That's on average over the four-year term, so it's supposed to represent an annual amount. So it's close to the four dollars by the time you get to the end, the 4.21.

**MR. McNULTY:** Oh, a dollar per year.

**MR. ALDAZABAL:** Per year, yeah.

**MR. McNULTY:** Oh, okay. Thanks.

Any other questions on the presentation, anyone?

**MR. REHWINKEL:** And, Bill, I wanted to add one thing to -- Carlos made a very accurate presentation on the slide show, and I just wanted to point to that document that you were talking about. He talked about the sharing incentive, and I think an important incentive that's in here that Tampa Electric mentions in the bullet point document is the incentive they have to bring in the first 400 -- two-thirds of the SoBRAs under 1,475 in order to build the last 50 megawatts. So we think that's also a powerful incentive to keep costs down in addition to the, to the sharing. So they, they pointed it out here, but we think it's -- it is an effective incentive.

**MR. WAHLEN:** Can I make one more clarification just so everybody is clear? The numbers for the revenue requirement in -- on page 10 of the agreement and the bullet points and the rate schedules are all calculated at a $1,500 cost cap. That's a cap. It's not a build to number. It's not a, you know, you can do it for that much, if you want to.

When we file for our SoBRA approval, we will be using our best estimate of what the actual projected cost will be. So in each instance we're hopeful that the actual amount of revenue requirement that shows up in rates for each SoBRA will be less than what you see in -- on page 10 and in these charts.

**MR. McNULTY:** Right. And that's in the settlement agreement.

**MR. WAHLEN:** It's in the settlement agreement, but I just wanted to make sure that no one concludes that we're going to do everything at 1,500 and go to the house.

**MR. WRIGHT:** Elisabeth, did you have a question?

**MS. DRAPER:** Yeah, for Bill Ashburn, a quick question on the rate design.

**MR. ASHBURN:** Uh-huh.

**MS. DRAPER:** Can you talk a little bit more as to what led lighting to only get 40 percent of the increase, or what's the basis for that?

**MR. ASHBURN:** Well, it's a negotiated agreement.

**MS. DRAPER:** Yes.

**MR. ASHBURN:** My lawyers taught me how to say that. So there was a lot of discussion among the parties what to do, and that was how we reached accommodation with regard to lighting.

**MS. DRAPER:** Okay.

**MR. WRIGHT:** I had a question, which is why I knew she wanted to ask one first. I want to -- I'm just trying to understand what this table is. Did somebody say that the 500 is a typo?

**MR. ASHBURN:** Yes, it's a typo.

**MR. WRIGHT:** It should be 600.

**MR. ASHBURN:** It should be 600, yes.

**MR. WRIGHT:** And is this what the 2017 revenue requirements would be if you put all 600 in in '17?

**MR. ASHBURN:** Yes.

**MR. WRIGHT:** Okay. Thank you.

**MR. ASHBURN:** Remember, between now and each year as we do it, loads could change, so we have a whole different 12CP -- not a whole different, but there will be slight differences in the 12CP allocator, there's going to be differences in the billing determinants. All those will work themselves into each tranche as it goes along. But this is all we have for now, so we used that.

**MR. WRIGHT:** Sure. And, correspondingly, the rate impacts that back up, these are the rate impacts that would be expected in 2017 using 2017 billing determinants if you dropped all 600 megawatts in in '17.

**MR. ASHBURN:** That is correct.

**MR. WRIGHT:** Thank you.

**MR. MOYLE:** Or just stated a little differently, the backup sheets there, you could also look at it as these would be the rate impacts -- you know, it's a little too simple to say over four years, but it's not all happening on day one. You're going to have different things coming in at different times, and so just to depict it, you've said, "Here's what it would look like over the term of the life," but we understand --

**MR. ASHBURN:** It's going to grow into it, but that's what it looks like at the end based on current numbers.

**MR. MOYLE:** Okay. Thanks.

**MR. McNULTY:** Any other questions about documents that have been distributed today or in yesterday's filing?

**MS. DRAPER:** One more follow-up question. You said something about the capacity factor in the last -- I didn't quite catch all that. Something would change with the capacity factor in the last year.

**MR. ASHBURN:** Well, since the recovery of the SoBRA from the rates that have demand rates is going to be recovered through the demand charges only, as your load factor changes, say, between years, if your load factor should change, it would change the overall bill impact depending on whether your load factor went up or down. Higher load factor customers will see a better benefit than lower load factor customers.

**MS. DRAPER:** And that is maybe unusual to just allocate an increase to the demand charge; is that correct?

**MR. ASHBURN:** It was part of the negotiation.

**MR. McNULTY:** Okay. I think at this point we can proceed to just kind of go paragraph by paragraph through the settlement and allow staff to approach a microphone and ask any questions that they feel like they need a better understanding of the settlement, you know, if there is any confusion whatsoever as to what they think the settlement might mean. And so for that purpose, we'll just start at, at paragraph 1 and -- which is page 3.

The first paragraph is titled "Term." Any questions?

Okay. Moving along. "Return," paragraph 2, "Return on Equity and Equity Ratio."

Okay. That's 2A and 2B, 2C. All right.

Paragraph 3, "Customer rates," subparagraph A, B. Oh, hold on. We've got a winner.

**MS. HARLOW:** E.

**MR. McNULTY:** What's that?

**MS. HARLOW:** Keep going.

**MR. McNULTY:** Oh, okay. I'm sorry. C, D, E.

**MS. HARLOW:** Judy Harlow with staff. On 3E I have some questions about the increases in credits. So I'm assuming that those increases were just part of the negotiations; is that correct?

**MR. ALDAZABAL:** Yes.

**MR. ASHBURN:** Yes.

**MS. HARLOW:** I see a thumbs up for our court reporter.

Did the company complete any of the three cost-effectiveness tests that the Commission uses on DSM?

**MR. ALDAZABAL:** Yes.

**MS. HARLOW:** Yes. And --

**MR. ALDAZABAL:** They passed the RIM test at the higher levels.

**MS. HARLOW:** They passed the RIM test.

Okay. TRC?

**MR. ALDAZABAL:** If it passes RIM, it passes TRC, yes.

**MS. HARLOW:** Correct. And participants?

**MR. ALDAZABAL:** Yes.

**MS. HARLOW:** Yes. Thank you.

If paragraph 3E of the petition is approved, do you have a feel for the anticipated impact on the 2019 ECCR factors?

**MR. ALDAZABAL:** I do not. I don't know if -- Bill, do you have --

**MR. ASHBURN:** I don't think I brought it with me. I'm sure it's somewhere.

**MR. ALDAZABAL:** We can get that.

**MS. HARLOW:** Thank you. I think we'll ask that through discovery.

**MR. ALDAZABAL:** That's fine.

**MS. HARLOW:** And one final question. If you look at the paragraph 3E, and I believe it's the next to last sentence, and I'll just read this, "The level of these credits will not change during the term and will remain in effect after the expiration of the term until changed, if at all, by a future unanimous agreement of the parties approved by final order of the Commission or final order of the Commission issued as a result of a future general base rate proceeding."

And my question is does this limit the Commission's ability to evaluate the credits in a future DSM goal or plan proceeding?

**MR. ALDAZABAL:** I'll defer to --

**MR. WRIGHT:** I would say it does not limit the Commission's ability to evaluate. It does limit the Commission's ability to change them until some future general base rate proceeding is resolved.

**MS. BROWNLESS:** Is that everybody else's --

**MR. WAHLEN:** I think, I think Tampa Electric would agree with that.

**MS. HARLOW:** And is it your understanding that

that would be the case if the Commission determined that those credits at that level were no longer cost-effective?

**MR. WRIGHT:** Yes.

**MS. HARLOW:** Just clarification.

**MR. WRIGHT:** Yeah.

**MS. HARLOW:** Okay. Thank you.

**MR. WRIGHT:** Then, of course, the Commission can sua sponte after 2021 bring them in for a general rate case, if they want to do that.

**MS. HARLOW:** Thank you.

**MR. McNULTY:** Okay. 3F, 3G.

Okay. Paragraph 4, "Other Cost Recovery."

**MR. ELLIS:** I've got one on that, and this is just to verify. I know there's a separate docket associated with this, but this would also allow recovery of things similar to what's being requested in Docket 20170199, the streetlight unamortized depreciation. That is the type of thing envisioned by this, or am I incorrect?

**MR. REHWINKEL:** I don't know exactly what's at issue in that docket off the top of my head.

**MR. ELLIS:** All right. We may just follow that up with some written discovery just to be specific. I assume that's what they were referring to by traditional historically. I think there was a case in 1980 where it was allowed, but not recently. But I didn't know if that's what that wording was meant to include.

**MR. ALDAZABAL:** Right. It was really more to prevent us trying to seek recovery of something that hadn't historically or traditionally been recovered through a clause. It's more of a limitation.

**MR. REHWINKEL:** Yeah. Which, which specific sentence are you talking about, Phillip?

**MR. ELLIS:** I believe it's -- all right. It looks like the -- which sentence is this? -- the third sentence, I think. "It is the intent of the parties that, in conjunction with the provisions of subparagraph 3A, the company shall not seek to recover nor shall the company be allowed to recover," et cetera. I'm sorry. It's the sentence before that, so the first sentence there. So the first sentence, "A, of a type traditionally or historically recovered through cost recovery clauses."

It's just usually depreciation addressed through here in a base rate proceeding, but this is one going through a clause, but it had gone through a clause in a prior proceeding albeit an older one.

**MR. REHWINKEL:** Yeah. I mean, I think that would be contemplated. This, this -- I mean, the thrust of this is that issue that was in the FPUC case, that -- kind of a poster child of what this -- would be prohibited in the second sentence there. The rest of it is not intended to disrupt the status quo of how rates have been handled, you know, even if it's a rare occasion. But if it's been done that way, we're not trying to change that.

**MR. McNULTY:** Okay. Paragraph 5, "Storm Damage," A, B, C, D.

Paragraph 6, "Solar Base Rate Adjustment Mechanism," subparagraph A, B, C.

**MR. RICHARDS:** I have a question about subparagraph D.

**MR. McNULTY:** All right. We're there.

**THE COURT REPORTER:** Your name?

**MR. RICHARDS:** My name is Chris Richards with Commission staff.

On page 13, subparagraph 6D, the second to last sentence, the debt rate utilized to calculate the revenue requirements, they'll be updated to reflect the incremental cost of prospective long-term debt issuances during the first 12 months. Can you explain how that, exactly how that will work?

**MR. ALDAZABAL:** If we go out and issue long-term debt at a, say, it's a 5 percent rate six months after a SoBRA is being built, we would use that 5 percent long-term debt rate calculating the revenue requirements.

**MR. WAHLEN:** In the true-up.

**MR. ALDAZABAL:** In the, in the true-up, yeah.

**MR. RICHARD:** Okay. Now does it assume that whatever the rate that the company comes up with, is that indisputable or will there be an avenue to arrive at a rate acceptable to all parties? Like, if we had an issue with the --

**MR. ALDAZABAL:** In the estimated -- when we file for a tranche, we will show the calculation of the revenue requirements and the interest rate we used, we will show, if there's a debt issuance, what -- I mean, the estimate that we use right now is 4.5 percent. That's our latest, last debt issuance. That's the cost we've got. So if we issue debt at a different rate, again, we'll show it and we'll point to it and we can provide documentation showing that that was what it was issued at.

**MR. WRIGHT:** Is your question will staff or any party be able to challenge the prudence of the rate?

**MR. RICHARD:** Right. Yeah. If you guys, you know, if you guys were to come and say, you know, it's

10 percent or something like that, if staff had an issue with that, is there any way --

**MR. MOYLE:** I would say you could raise it or the parties could raise it. You probably want to hear that from TECO, but that's my view of the world based on our discussions.

**MR. ALDAZABAL:** That certainly can be raised, but we're pretty confident that our treasury group is always in the market trying to seek the lowest possible rate.

**MR. RICHARDS:** Okay. But, so if there is an issue, though, any of the parties can raise concern on that?

**MR. ALDAZABAL:** Uh-huh.

**MR. RICHARD:** Okay. Thank you.

**MR. McNULTY:** Subparagraph E, F.

**MR. ELLIS:** My understanding of this is if, say, TECO decided to do an 80-megawatt project that would fall under the PPSA, it would not be eligible for the SoBRA -- is that correct? -- or --

**MR. ALDAZABAL:** Well, it would be subject to a need determination, so we wouldn't likely do an 80-megawatt project. The cap is, the cap is the caps that we have listed on the agreement. So 80 megawatts, we're not precluded from doing that, but we would have to go through a need determination process.

**MR. ELLIS:** So it would still be eligible for the SoBRA for recovery of those costs, but you'd also just have to go through the PPSA beforehand anyways.

**MR. ALDAZABAL:** Yes.

**MR. ELLIS:** Okay.

**MR. McNULTY:** G, H, I -- and that's all of I, 1 and 2, 3 -- J, K, L, M, N, O.

**MR. ELLIS:** Just to be specific, we are talking about FPL and not any other utility for O? So just their 110-megawatt statutory and not those allowed through -- and just am I clear of what they do for that?

**MR. ALDAZABAL:** (Nods affirmatively.)

**MR. ELLIS:** Okay.

**MR. REHWINKEL:** Yeah. I mean, I don't think there's any way that Duke will be filing one. So, yeah, they're -- under -- they're not called out, but they are practically and factually the only one that could be filing, yeah.

**MR. MOYLE:** And the intent behind this is to capture the information that's contained in those monthly filings now. So we want the same, same information, I think a similar provision, if not the exact same provision, in the Duke settlement as well.

**MR. McNULTY:** Subparagraph P, Q, and R.

Okay. Paragraph 7 is "Earnings." Paragraph -- subparagraph A, B, C, D, E.

Paragraph 8, which is "Depreciation," A, B, C.

Paragraph 9, "Federal Income Tax Reform," A, B, C.

"Incentive Plan," paragraph 10.

**MR. ELLIS:** This may be skipping ahead a little bit, but in the incentive plan it's a very broad plan, among other things, you know, other programs that may be considered. Just to jump ahead to 11E regarding RECs, so, for example, sales of RECs wouldn't necessarily be eligible through the incentive plan to have cost sharing. It would all -- all REC sales would flow back. It wouldn't count towards this 4.5 million cap.

**MR. ALDAZABAL:** That's correct.

**MR. ELLIS:** Okay.

**MR. McNULTY:** Paragraph 11, "Other," A.

**MS. BROWNLESS:** I want to make sure I understand what you intend the effect of this settlement agreement to be on the current hedging docket. So obviously you're not going to enter into any new natural gas financial hedging contracts pursuant.

**MR. ALDAZABAL:** Right.

**MS. BROWNLESS:** And with regard to B, at this time do you have any investments in oil or natural gas exploration?

**MR. ALDAZABAL:** No.

**MS. BROWNLESS:** So this was kind of a preemptive strike sort of provision, is that --

**MR. WAHLEN:** It was a negotiated term.

**MS. BROWNLESS:** Okay.

**MR. ASHBURN:** I taught him how to say that.

**MS. BROWNLESS:** Thank you.

**MR. REHWINKEL:** A self-inflicted negotiation.

(Laughter.)

**MS. BROWNLESS:** Okay. All right. That's all I had for that.

**MR. BARRETT:** May I ask a question? Michael Barrett of staff.

On 11A, and maybe Suzanne got to this, but why would the hedging provision have a different term than the overall global agreement?

**MR. WAHLEN:** Because it was a negotiated term.

**MR. BARRETT:** Is this the only instance of a date outside of the global agreement?

**MR. WAHLEN:** I'm a lawyer, so words like "only" make me nervous, but --

**MR. MOYLE:** I don't think so.

**MR. ALDAZABAL:** Not necessarily.

**MR. WAHLEN:** We've agreed to also, in B --

**MR. REHWINKEL:** The credits, for one thing.

**MR. WAHLEN:** And the credits remain in effect --

**MR. REHWINKEL:** And if they live beyond.

**MR. ALDAZABAL:** And depreciation could live beyond too.

**MR. WRIGHT:** All rates, yeah, all rates stay in effect. I don't -- I'm not, I'm not sure that there's another actual specific date that says it continues till X, but it's clear that the agreement continues on until either a future agreement of these parties or a future final general base rate order, and that applies to everything in there.

**MR. REHWINKEL:** I mean, their ability to put a SoBRA in in the last tranche goes beyond the twenty -- the 12/31/21, things like that.

**MR. WRIGHT:** Yeah. And actually there -- I think there is -- I think there are references in here to 2022 for, for the 50-megawatt tranche. That's true. Yeah.

**MR. BARRETT:** That was all. Thank you.

**MR. ELLIS:** I actually kind of had a fallout associated back with -- sorry to jump all the way back to 3E.

**MR. REHWINKEL:** Too late.

(Laughter.)

**MR. ELLIS:** So as part of this, the inclusion of the level of credits will not change during the term or remain in effect until the expiration or, you know, da, da, da, da, da, da. So this is a perpetuity for that. So any future for the next, picking a random number from my head, hundred years, it will only be allowed to be changed in any base rate proceeding based upon this agreement, or is it just the next, is it the next final order that that changes, and then after that it will be evaluated at that time? Or is this a binding forever-hold-your-peace type thing.

**MR. MOYLE:** I mean, forever is a long time, so I don't, I don't think it's forever. But I don't -- I look at it like rates in that just because the term of this agreement expires, that doesn't mean that the rates that TECO has put in place through the SoBRA to pay for that, for those assets go away as well. You know, I think they continue until, until there's another general base rate proceeding.

**MR. ELLIS:** But after that one, this paragraph, this portion would no longer apply after that next proceeding.

**MR. ALDAZABAL:** Right.

**MR. ELLIS:** So the proceeding after that would be whenever --

**MR. WRIGHT:** The term will be over and the future action contemplated by the agreement would have occurred. And so, so this -- you know, in that scenario, when there's a future general base rate order or an order approving a future agreement of the parties approved by the Commission, that this is, this is done --

**MR. REHWINKEL:** Well, while you're dealing with hypotheticals, this could be carried forward in a settlement and readopted, et cetera. But, yes.

**MR. MOYLE:** Plus you have the rule of perpetuity come into play.

**MR. WRIGHT:** And just a follow-up, Jon said, Phillip, the -- 6P says exactly the same thing with respect to all the base rates.

**MR. McNULTY:** 11B, C, D, E, F.

Paragraph 12, "New Tariffs."

Paragraph 13, "Application of 2017 Agreement."

Paragraph 14, "Commission Approval." That's A, B, C, and D.

Paragraph 15, "Disputes," and paragraph 16, "Execution."

**MS. BROWNLESS:** Okey-dokey. Let me see here.

We anticipate that we will send out the data requests, the first data request on the 16th. Let's see. Is that right? That's wrong, isn't it? On the 11th; right? We'll send them on the 11th, and they'll be due on the 16th. And if we have to do a second round of data requests, they'll be sent on the 19th and due on the 24th because the idea is for all discovery to be completed by the 30th of October.

We do have a procedural order which I hope will be issued today, and what that says is that there will be a hearing on November 6th. We do not -- have not set a prehearing conference. There -- we anticipate that there will be a bench decision on November 6th, but that, of course, is contingent upon there being no Intervenor who requests to brief any aspect of the settlement agreement.

If a bench decision is not made, the Commission will set a Special Agenda Conference. We don't have a date for that at this time. And briefs, if any, will be due November 16th, ten days after the hearing.

Data requests, everybody will be given an opportunity to have 150 data requests. You have five days to answer them. Please provide affidavits with the responses to all data requests.

Let's see. We do anticipate putting the following exhibits into the record: The stipulation; staff data requests; any other data requests, should anybody else request them. If there -- there is going to be an opportunity for public comment. The public comment will be under oath. To the extent that the public has any papers or things that they wish to include, we'll treat those just like we do any exhibits or papers that parties have at customer meetings for a rate case. So those will be put in there.

It's anticipated that kind of the way this will work is that we'll start the proceeding, we'll have opening statements, everybody is limited to eight minutes, then we'll do the public testimony. Once that is concluded, the anticipation is that there will be a panel presented, as many people as y'all think are necessary to answer the relevant questions. Everybody will be sworn in, put them all up there at the same time. That will allow the Commissioners to ask their questions.

After the Commissioners have completed their questions, we will put the exhibits into the record. We might do a short composite exhibit list, but since I don't anticipate there to be more than three exhibits, I may not. You know, if it makes you happy, I'll do a composite exhibit list. Do you want a composite exhibit list?

**MR. WAHLEN:** I think we can count to three.

**MS. BROWNLESS:** Yeah, I thought you guys were pretty good with that.

We'll move the -- we'll ask that the exhibits be admitted into the record, and then at the conclusion of that we'll close the record. Then, as I say, if procedurally allowable, the Commission will go ahead and open the voting and the debate and do what they're going to do, and then we'll get a bench decision.

As you all know, and I need not tell any of you guys here who are all old hands at this as well, if there is an Intervenor who is not a signatory to the agreement who wishes to brief any aspect of it, they, of course, will be given an opportunity to do that. That will require a Special Agenda to be set. We don't have a date for that yet. And then the Commissioners will vote at the Special Agenda.

So we are basically going to use the same procedure that will be used in the Duke case. We're trying to make sure, you know, that we're treating everybody the same. And at this time, having heard all that, does anybody have any problem with that?

**MR. MOYLE:** I have just a couple of questions, if I could.

**MS. BROWNLESS:** Sure.

**MR. MOYLE:** So the panel that you're contemplating, does the Prehearing Order say who that's going to be, or is that at the discretion of --

**MS. BROWNLESS:** No, that's up to the discretion of the IOU, and, of course, they will all be sworn in.

**MR. WAHLEN:** But we're anticipating that it's just going to be Tampa Electric Company people, not --

**MR. MOYLE:** Yeah, not others.

And the other question I had, because I know we have a court reporter here today, which I think is helpful, will the -- you're not -- yeah, you're a court reporter.

**MS. BROWNLESS:** Yeah, she's a court reporter, yeah.

**MR. MOYLE:** Suzanne is shaking her head no.

**MS. BROWNLESS:** Yes, I anticipated the next question.

**MR. MOYLE:** Should we adjourn the meeting now, Suzanne? No.

(Laughter.)

No, I was curious as to two things really. Where can we get the transcript, and -- of this hearing today, the discussions today, and then whether it might make sense to even put it as an exhibit in the, in the hearing. Because you asked a lot of questions. You asked, "Well, what does this mean, what does this mean, and what does that mean?" And, you know, it's informative with respect to the intent, you know, of the parties. So I just want to make sure that I can put my hands on the transcript at some point in the future.

**MS. BROWNLESS:** Okay. In answer to your question, number one, the transcript will be filed in the docket. So you'll have the ability to do it.

Number two, I don't want to make it as an exhibit. It's not under oath. It's basically just an informal meeting. I can assure you that the staff will have very detailed data requests that capture the questions that were asked and the answers that were given, giving the parties an opportunity to provide similar answers.

**MR. MOYLE:** Got it.

**MR. WRIGHT:** I have a -- I have no problem with everything you laid out, Suzanne. I have a very simple question. Have you figured out or scheduled with the Chair's office a time of day for the hearing on November 6th?

**MS. BROWNLESS:** It's at 1:00 o'clock.

**MR. WRIGHT:** Thank you.

**MS. BROWNLESS:** And that's going to be in the procedural order.

**MR. WRIGHT:** Yeah, that's great. Thanks.

**MR. MOYLE:** I did have one other thing. I think we've covered this in Duke, but just to be clear here, so the people who signed the agreement, there's no need to intervene in the docket. We're dispensable parties and --

**MS. BROWNLESS:** We have, we have a line in the procedural order that specifically says that for the purposes of this docket, all signatories to the 2017 agreement shall be deemed full parties of record in this proceeding with all the rights and duties of same. So you don't have to file anything or do anything.

**MR. MOYLE:** Thank you.

**MS. BROWNLESS:** And I think that's it for me. Y'all got anything else?

**MR. WAHLEN:** Just another thank you. We know that this is a lot of work for staff. We've been working on it a long time, and we appreciate you hustling around to help us get this done and in place so our customers can get the benefits of the agreement by the first of the year. We very much appreciate that.

**MS. BROWNLESS:** You're very welcome. We have only one other thing. If there's anybody on the phone now that wishes to say anything, we're getting ready to quit, so now is your chance.

(No response.)

Hearing no response, I will assume there's no one who wishes to add anything, and we'll be adjourned. Thank you so much.

(Meeting adjourned at 2:32 p.m.)

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

I, LINDA BOLES, CRR, RPR, Official Commission Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 11th day of October, 2017.

Linda Boles
______________________________

LINDA BOLES, CRR, RPR
FPSC Official Hearings Reporter
(850) 413-6734

Parties/Staff Handout
event date 10 / 4 / 2017
Docket No. 20170210-EI

Tampa Electric Company
2017 Agreement

- Parties: Tampa Electric, OPC, FIPUG, FRF, FEA, HUA, with separate statement of support by SACE.
- The 2017 Agreement – by and large a four year (2018-2021) extension of the 2013 Settlement Agreement.
- Four year rate freeze (with exceptions discussed below) through 2021 with same ROE and similar cap structure as in the 2013 Agreement.
- SoBRA in 2017 Agreement takes place of GBRA in 2013 Agreement.
- SoBRA (2018-2021), as follows:

| Year | Earliest Rate Change And In-Service Date | Maximum Incremental SoBRA MW | Maximum Incremental Annualized SoBRA Revenue Requirements (millions) | Maximum Cumulative SoBRA MW | Maximum Cumulative Annualized SoBRA Revenue Requirements (millions) |
|---|---|---|---|---|---|
| 2018 | September 1 | 150 | $30.6[1] | 150 | $30.6 |
| 2019 | January 1 | 250 | $50.9 | 400 | $81.5 |
| 2020 | January 1 | 150 | $30.6 | 550 | $112.1 |
| 2021 | January 1 | 50 | $10.2 | 600 | $122.3[2] |

- Installed Cost Cap - $1,500/kW_{ac}$ (lowest of recently approved and proposed SoBRAs).
- Incentive to minimize installed cost – 75% / 25% (customer/company) sharing of cost differential below $1,500/kW$_{ac}$.
- Additional incentive – If first 400 MW (subject to a 2% variance) have installed cost of $1,475/kW$_{ac}$ or less Tampa Electric can add final 50 MW of the maximum 600 MW (subject to same $1,500/kW$_{ac}$ cost cap).
- Cost effectiveness test like that approved for FPL SoBRA.
- Provision to capture potential federal income tax revision for benefit of customers.

[1] The annual revenue requirement is approximately $30.6 million, however, since the first 150 MW Tranche is scheduled to come online September 1, 2018, the revenue requirements collected would be four months of the annual revenue requirements, or $10.2 million.
[2] The 2021 Tranche can be included in and its costs recovered under the SoBRA mechanism only if the projects constituting the 2018 and 2019 Tranches in this table are in-service and operating per design specifications as of December 31, 2019, and were constructed at an average capital cost of no more than $1475 per kW$_{ac}$.

- Five year moratorium on financial hedging of natural gas prices – through December 31, 2022.

- No recovery of oil/gas exploration, production, etc. costs for five years.

- Requests Commission approval of incentive mechanism like that pending for Tampa Electric in Docket No. 2016010-EI, but with higher thresholds than the Company had proposed.

- Slight increases in standby generator and Contracted Credit Value ("CCV") credits.

- Carry-over provisions applicable from 2013 Agreement:

    - Named storm damage cost recovery.

    - ROE adjustment if Treasury Bond rates exceed a trigger threshold.

    - Continuation of Economic Development Rider.

- Straightforward, uncomplicated Agreement.

- Fair to all, bringing an increased focus on clean solar power, zero-cost fuel, reduced carbon footprint, with minimal cost to customers. All-in, estimated one percent cost increase to residential customer ($1.00 per 1,000 kWh).

Parties/Staff Handout
event date 10 / 4 / 2017
Docket No. 20170210-EI

# TAMPA ELECTRIC COMPANY
## DEVELOPMENT OF SoBRA BASE REVENUE INCREASE BY RATE CLASS
## USING JANUARY 1, 2017 RATES ADJUSTED FOR SoBRA
## ($000)

600 ~~500~~ MW SoBRA
12CP &1/13 - All Demand

| Line | | Rate Class | (A) Adjusted Revenue Requirement(1) | (B) Present Base Revenue(2) | (C) Base Revenue Deficiency $ (A) - (B) | (D) Base Revenue Deficiency % (C) / (B) | (E) Proposed Base Rev. Increase $ | (F) Proposed Base Rev. Increase % (E) / (B) | (G) 2017 Targeted Base Revenue (B) + (E) |
|---|---|---|---|---|---|---|---|---|---|
| 1 | I. | Residential (RS,RSVP) | $ 694,497 | $ 627,009 | $ 67,487 | 10.76% | | | |
| 2 | | | | | | | | | |
| 3 | II. | General Service | | | | | | | |
| 4 | | Non-Demand (GS,CS) | 78,303 | 71,988 | 6,315 | 8.77% | | | |
| 5 | | | | | | | | | |
| 6 | | | | | | | | | |
| 7 | | Sub-Total: I. + II. | $ 772,800 | $ 698,997 | $ 73,802 | 10.56% | $ 73,802 | 10.56% | $ 772,800 |
| 8 | | | | | | | | | |
| 9 | | | | | | | | | |
| 10 | III. | General Service | | | | | | | |
| 11 | | Demand (GSD, SBF) | 389,424 | 346,008 | 43,416 | 12.55% | $ 43,416 | 12.55% | 389,424 |
| 12 | | | | | | | | | |
| 13 | IV. | Interruptible Service (IS/SBI) | 38,683 | 35,035 | 3,648 | 10.41% | $ 3,648 | 10.41% | 38,683 |
| 15 | | | | | | | | | |
| 16 | | | | | | | | | |
| 19 | V. | Lighting (LS-1) | | | | | | | |
| 20 | | A. - Energy | $ 6,003 | 5,867 | 136 | 2.31% | $ 136 | 2.31% | $ 6,003 |
| 21 | | B. - Facilities | 43,545 | 43,545 | - | 0.00% | $ - | 0.00% | $ 43,545 |
| 22 | | | | | | | | | |
| 23 | | | | | | | | | |
| 24 | | Total | $ 1,250,454 | $ 1,129,452 | $ 121,002 | 10.71% | $ 121,002 | 10.71% | $ 1,250,454 |
| 25 | | | | | | | | | |
| 26 | | | | $ 121,002 | | | | | |
| 27 | | | | | | | | | |

28 (1) The Adjusted Revenue Requirement column reflects an increase of $121.0 million annual SoBRA revenues based on each class' percentage of 12 CP & 1/13th allocator
29 plus an 40% allocation to lighting service of SoBRA increase.
30 (2) Present base revenue is calculated using rates in effect on January 16, 2017.

SOBRA
12CP and 1/13 With 40% Allocation to Lighting
All Demand

August 15, 2017

SCHEDULE A-2 | FULL REVENUE REQUIREMENTS BILL COMPARISON - TYPICAL MONTHLY BILLS | 

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: For each rate, calculate typical monthly bills for present rates and proposed rates.

Type of data shown:
XX Projected Test year Ended 12/31/2017

COMPANY: TAMPA ELECTRIC COMPANY

## RS - RESIDENTIAL SERVICE

| Line No. | RATE SCHEDULE RS (1) TYPICAL KW | (2) TYPICAL KWH | BILL UNDER PRESENT RATES (3) BASE RATE | (4) FUEL CHARGE | (5) ECCR CHARGE | (6) CAPACITY CHARGE | (7) ECRC CHARGE | (8) GRT CHARGE | (9) TOTAL | BILL UNDER PROPOSED RATES (10) BASE RATE | (11) FUEL CHARGE | (12) ECCR CHARGE | (13) CAPACITY CHARGE | (14) ECRC CHARGE | (15) GRT CHARGE | (16) TOTAL | INCREASE (17) DOLLARS (16)-(9) | (18) PERCENT (17)/(9) | COSTS IN CENTS/KWH (19) PRESENT (9)/(2)*100 | (20) PROPOSED (16)/(2)*100 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 0 | - | $ 16.62 | $ - | $ - | $ - | $ - | $ 0.43 | $ 17.05 | $ 16.62 | $ - | $ - | $ - | $ - | $ 0.43 | $ 17.05 | $ - | 0.0% | - | - |
| 2 | | | | | | | | | | | | | | | | | | | | |
| 3 | 0 | 100 | $ 21.82 | $ 2.64 | $ 0.23 | $ 0.09 | $ 0.30 | $ 0.65 | $ 25.81 | $ 22.60 | $ 2.39 | $ 0.24 | $ 0.09 | $ 0.39 | $ 0.66 | $ 26.36 | $ 0.55 | 2.1% | 25.81 | 26.36 |
| 4 | | | | | | | | | | | | | | | | | | | | |
| 5 | 0 | 250 | $ 29.62 | $ 6.61 | $ 0.56 | $ 0.22 | $ 0.97 | $ 0.97 | $ 38.95 | $ 31.56 | $ 5.97 | $ 0.59 | $ 0.22 | $ 0.97 | $ 1.01 | $ 40.32 | $ 1.37 | 3.5% | 15.58 | 16.13 |
| 6 | | | | | | | | | | | | | | | | | | | | |
| 7 | 0 | 500 | $ 42.62 | $ 13.21 | $ 1.13 | $ 0.44 | $ 1.95 | $ 1.52 | $ 60.86 | $ 46.51 | $ 11.94 | $ 1.18 | $ 0.44 | $ 1.95 | $ 1.59 | $ 63.60 | $ 2.74 | 4.5% | 12.17 | 12.72 |
| 8 | | | | | | | | | | | | | | | | | | | | |
| 9 | 0 | 750 | $ 55.62 | $ 19.82 | $ 1.69 | $ 0.66 | $ 2.92 | $ 2.07 | $ 82.77 | $ 61.45 | $ 17.91 | $ 1.77 | $ 0.66 | $ 2.92 | $ 2.17 | $ 86.88 | $ 4.11 | 5.0% | 11.04 | 11.58 |
| 10 | | | | | | | | | | | | | | | | | | | | |
| 11 | 0 | 1,000 | $ 68.62 | $ 26.42 | $ 2.26 | $ 0.88 | $ 3.89 | $ 2.62 | $ 104.68 | $ 76.39 | $ 23.88 | $ 2.36 | $ 0.88 | $ 3.89 | $ 2.75 | $ 110.16 | $ 5.48 | 5.2% | 10.47 | 11.02 |
| 12 | | | | | | | | | | | | | | | | | | | | |
| 13 | 0 | 1,250 | $ 84.39 | $ 35.53 | $ 2.81 | $ 1.10 | $ 4.86 | $ 3.30 | $ 131.99 | $ 93.63 | $ 32.35 | $ 2.95 | $ 1.10 | $ 4.86 | $ 3.46 | $ 138.56 | $ 6.57 | 5.0% | 10.56 | 11.08 |
| 14 | | | | | | | | | | | | | | | | | | | | |
| 15 | 0 | 1,500 | $ 100.16 | $ 44.63 | $ 3.38 | $ 1.32 | $ 5.84 | $ 3.96 | $ 159.30 | $ 111.28 | $ 40.82 | $ 3.54 | $ 1.32 | $ 5.84 | $ 4.17 | $ 166.98 | $ 7.68 | 4.8% | 10.62 | 11.13 |
| 16 | | | | | | | | | | | | | | | | | | | | |
| 17 | 0 | 2,000 | $ 131.70 | $ 62.84 | $ 4.50 | $ 1.76 | $ 7.78 | $ 5.35 | $ 213.93 | $ 146.16 | $ 57.76 | $ 4.72 | $ 1.76 | $ 7.78 | $ 5.59 | $ 223.77 | $ 9.85 | 4.6% | 10.70 | 11.19 |
| 18 | | | | | | | | | | | | | | | | | | | | |
| 19 | 0 | 3,000 | $ 194.78 | $ 99.26 | $ 6.75 | $ 2.64 | $ 11.67 | $ 8.08 | $ 323.18 | $ 215.93 | $ 91.84 | $ 7.08 | $ 2.64 | $ 11.67 | $ 8.43 | $ 337.39 | $ 14.22 | 4.4% | 10.77 | 11.25 |
| 20 | | | | | | | | | | | | | | | | | | | | |
| 21 | 0 | 5,000 | $ 320.04 | $ 172.10 | $ 11.25 | $ 4.40 | $ 19.45 | $ 13.54 | $ 541.68 | $ 355.47 | $ 159.40 | $ 11.80 | $ 4.40 | $ 19.45 | $ 14.12 | $ 564.64 | $ 22.95 | 4.2% | 10.83 | 11.29 |

| Line No. | | PRESENT | PROPOSED |
|---|---|---|---|
| 22 | | | |
| 23 | | | |
| 24 | | PRESENT | PROPOSED |
| 25 | CUSTOMER CHARGE | 16.62 $/Bill | 16.62 $/Bill |
| 26 | DEMAND CHARGE | - $/KW | - $/KW |
| 27 | ENERGY CHARGE | | |
| 28 | 0 - 1,000 KWH | 5.200 ¢/KWH | 5.977 ¢/KWH |
| 29 | Over 1,000 KWH | 6.306 ¢/KWH | 6.977 ¢/KWH |
| 30 | FUEL CHARGE | | |
| 31 | 0 - 1,000 KWH | 2.642 ¢/KWH | 2.388 ¢/KWH |
| 32 | Over 1,000 KWH | 3.642 ¢/KWH | 3.388 ¢/KWH |
| 33 | CONSERVATION CHARGE | 0.226 ¢/KWH | 0.236 ¢/KWH |
| 34 | CAPACITY CHARGE | 0.088 ¢/KWH | 0.088 ¢/KWH |
| 35 | ENVIRONMENTAL CHARGE | 0.389 ¢/KWH | 0.389 ¢/KWH |
| 36 | | | |
| 37 | | | |
| 38 | Note: Cost recovery clause factors are the current 2017 factors. | | |
| 39 | | | |

Supporting Schedules: E-13c, E-14 Supplement

Recap Schedules:

SCHEDULE A-2 — FULL REVENUE REQUIREMENTS BILL COMPARISON - TYPICAL MONTHLY BILLS — 

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: For each rate, calculate typical monthly bills for present rates and proposed rates.

Type of data shown:
XX Projected Test year Ended 12/31/2017

COMPANY: TAMPA ELECTRIC COMPANY

## GS - GENERAL SERVICE NON-DEMAND

| | RATE SCHEDULE GS | | BILL UNDER PRESENT RATES | | | | | | | BILL UNDER PROPOSED RATES | | | | | | | INCREASE | | COSTS IN CENTS/KWH | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line No. | (1) TYPICAL KW | (2) TYPICAL KWH | (3) BASE RATE | (4) FUEL CHARGE | (5) ECCR CHARGE | (6) CAPACITY CHARGE | (7) ECRC CHARGE | (8) GRT CHARGE | (9) TOTAL | (10) BASE RATE | (11) FUEL CHARGE | (12) ECCR CHARGE | (13) CAPACITY CHARGE | (14) ECRC CHARGE | (15) GRT CHARGE | (16) TOTAL | (17) DOLLARS (16)-(9) | (18) PERCENT (17)/(9) | (19) PRESENT (9)/(2)*100 | (20) PROPOSED (16)/(2)*100 |
| 1 | 0 | - | $ 19.94 | $ - | $ - | $ - | $ - | $ 0.51 | $ 20.45 | $ 19.94 | $ - | $ - | $ - | $ - | $ 0.51 | $ 20.45 | $ - | 0.0% | - | - |
| 2 | | | | | | | | | | | | | | | | | | | | |
| 3 | 0 | 100 | $ 25.49 | $ 2.96 | $ 0.20 | $ 0.08 | $ 0.39 | $ 0.75 | $ 29.86 | $ 26.23 | $ 2.68 | $ 0.21 | $ 0.08 | $ 0.39 | $ 0.76 | $ 30.35 | $ 0.49 | 1.6% | 29.86 | 30.35 |
| 4 | | | | | | | | | | | | | | | | | | | | |
| 5 | 0 | 250 | $ 33.81 | $ 7.39 | $ 0.51 | $ 0.19 | $ 0.97 | $ 1.10 | $ 43.97 | $ 35.67 | $ 6.70 | $ 0.54 | $ 0.19 | $ 0.97 | $ 1.13 | $ 45.19 | $ 1.22 | 2.8% | 17.59 | 18.08 |
| 6 | | | | | | | | | | | | | | | | | | | | |
| 7 | 0 | 500 | $ 47.69 | $ 14.78 | $ 1.02 | $ 0.38 | $ 1.94 | $ 1.69 | $ 67.49 | $ 51.40 | $ 13.40 | $ 1.07 | $ 0.38 | $ 1.94 | $ 1.75 | $ 69.93 | $ 2.44 | 3.6% | 13.50 | 13.99 |
| 8 | | | | | | | | | | | | | | | | | | | | |
| 9 | 0 | 750 | $ 61.56 | $ 22.17 | $ 1.52 | $ 0.57 | $ 2.91 | $ 2.28 | $ 91.01 | $ 67.12 | $ 20.09 | $ 1.61 | $ 0.57 | $ 2.91 | $ 2.37 | $ 94.67 | $ 3.66 | 4.0% | 12.13 | 12.62 |
| 10 | | | | | | | | | | | | | | | | | | | | |
| 11 | 0 | 1,000 | $ 75.43 | $ 29.56 | $ 2.03 | $ 0.76 | $ 3.88 | $ 2.86 | $ 114.52 | $ 82.85 | $ 26.79 | $ 2.14 | $ 0.76 | $ 3.88 | $ 2.99 | $ 119.41 | $ 4.89 | 4.3% | 11.45 | 11.94 |
| 12 | | | | | | | | | | | | | | | | | | | | |
| 13 | 0 | 1,250 | $ 89.30 | $ 36.95 | $ 2.54 | $ 0.95 | $ 4.85 | $ 3.45 | $ 138.04 | $ 98.58 | $ 33.49 | $ 2.68 | $ 0.95 | $ 4.85 | $ 3.60 | $ 144.14 | $ 6.10 | 4.4% | 11.04 | 11.53 |
| 14 | | | | | | | | | | | | | | | | | | | | |
| 15 | 0 | 1,500 | $ 103.18 | $ 44.34 | $ 3.05 | $ 1.14 | $ 5.82 | $ 4.04 | $ 161.56 | $ 114.31 | $ 40.19 | $ 3.21 | $ 1.14 | $ 5.82 | $ 4.22 | $ 168.88 | $ 7.32 | 4.5% | 10.77 | 11.26 |
| 16 | | | | | | | | | | | | | | | | | | | | |
| 17 | 0 | 2,000 | $ 130.92 | $ 59.12 | $ 4.06 | $ 1.52 | $ 7.76 | $ 5.21 | $ 208.59 | $ 145.76 | $ 53.58 | $ 4.28 | $ 1.52 | $ 7.76 | $ 5.46 | $ 218.36 | $ 9.76 | 4.7% | 10.43 | 10.92 |
| 18 | | | | | | | | | | | | | | | | | | | | |
| 19 | 0 | 3,000 | $ 186.41 | $ 88.68 | $ 6.09 | $ 2.28 | $ 11.64 | $ 7.57 | $ 302.67 | $ 208.67 | $ 80.37 | $ 6.42 | $ 2.28 | $ 11.64 | $ 7.93 | $ 317.31 | $ 14.65 | 4.8% | 10.09 | 10.58 |
| 20 | | | | | | | | | | | | | | | | | | | | |
| 21 | 0 | 5,000 | $ 297.39 | $ 147.80 | $ 10.15 | $ 3.80 | $ 19.40 | $ 12.27 | $ 490.81 | $ 334.49 | $ 133.95 | $ 10.70 | $ 3.80 | $ 19.40 | $ 12.86 | $ 515.22 | $ 24.41 | 5.0% | 9.82 | 10.30 |
| 22 | | | | | | | | | | | | | | | | | | | | |
| 23 | 0 | 8,500 | $ 491.61 | $ 251.26 | $ 17.26 | $ 6.46 | $ 32.98 | $ 20.50 | $ 820.06 | $ 554.66 | $ 227.72 | $ 18.19 | $ 6.46 | $ 32.98 | $ 21.54 | $ 861.56 | $ 41.50 | 5.1% | 9.65 | 10.14 |

| Line No. | | PRESENT | PROPOSED |
|---|---|---|---|
| 26 | | PRESENT | PROPOSED |
| 27 | CUSTOMER CHARGE | 19.94 $/Bill | 19.94 $/Bill |
| 28 | ENERGY CHARGE | 5.549 ¢/kWH | 6.291 ¢/kWH |
| 29 | FUEL CHARGE | 2.956 ¢/kWH | 2.679 ¢/kWH |
| 30 | CONSERVATION CHARGE | 0.203 ¢/kWH | 0.214 ¢/kWH |
| 31 | CAPACITY CHARGE | 0.076 ¢/kWH | 0.076 ¢/kWH |
| 32 | ENVIRONMENTAL CHARGE | 0.388 ¢/kWH | 0.388 ¢/kWH |

37 Note: Cost recovery clause factors are the current 2017 factors.

Supporting Schedules: E-13a, E-14 Supplement

Recap Schedules:

# SOBRA
## 12CP and 1/13 With 40% Allocation to Lighting
## All Demand

August 15, 2017



FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: For each rate, calculate typical monthly bills for present rates and proposed rates.

Type of data shown:
XX Projected Test year Ended 12/31/2017

COMPANY: TAMPA ELECTRIC COMPANY

### GSD - GENERAL SERVICE DEMAND

RATE SCHEDULE GSD

| Line No. | (1) TYPICAL KW | (2) TYPICAL KWH | BILL UNDER PRESENT RATES (3) BASE RATE | (4) FUEL CHARGE | (5) ECCR CHARGE | (6) CAPACITY CHARGE | (7) ECRC CHARGE | (8) GRT CHARGE | (9) TOTAL |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 75 | 10,950 | $ 762.51 | $ 323.66 | $ 19.71 | $ 6.90 | $ 42.27 | $ 29.62 | $ 1,184.66 |
| 2 | 75 | 19,163 | $ 1,136.10 | $ 566.44 | $ 57.75 | $ 20.25 | $ 73.97 | $ 47.60 | $ 1,904.11 |
| 3 | 75 | 32,850 | $ 1,378.16 | $ 971.05 | $ 57.75 | $ 20.25 | $ 126.80 | $ 66.49 | $ 2,619.51 |
| 4 | 75 | 49,275 | $ 1,620.76 | $ 1,448.61 | $ 57.75 | $ 20.25 | $ 190.20 | $ 85.58 | $ 3,423.37 |
| 5 | | | | | | | | | |
| 6 | 500 | 73,000 | $ 4,895.04 | $ 2,157.86 | $ 131.40 | $ 45.99 | $ 281.78 | $ 192.62 | $ 7,704.71 |
| 7 | 500 | 127,750 | $ 7,388.98 | $ 3,776.29 | $ 365.00 | $ 135.00 | $ 493.12 | $ 312.52 | $ 12,500.90 |
| 8 | 500 | 219,000 | $ 8,999.50 | $ 6,473.64 | $ 365.00 | $ 135.00 | $ 845.34 | $ 431.76 | $ 17,270.24 |
| 9 | 500 | 328,500 | $ 10,616.61 | $ 9,658.72 | $ 365.00 | $ 135.00 | $ 1,268.01 | $ 565.73 | $ 22,629.27 |
| 10 | | | | | | | | | |
| 11 | 2000 | 292,000 | $ 19,480.44 | $ 8,631.52 | $ 525.60 | $ 183.96 | $ 1,127.12 | $ 767.91 | $ 30,716.55 |
| 12 | 2000 | 511,000 | $ 29,406.16 | $ 15,105.16 | $ 1,540.00 | $ 540.00 | $ 1,972.46 | $ 1,247.53 | $ 49,901.33 |
| 13 | 2000 | 876,000 | $ 36,898.28 | $ 25,894.56 | $ 1,540.00 | $ 540.00 | $ 3,381.36 | $ 1,724.46 | $ 68,976.66 |
| 14 | 2000 | 1,314,000 | $ 42,367.52 | $ 38,634.89 | $ 1,540.00 | $ 540.00 | $ 5,072.04 | $ 2,260.37 | $ 90,414.81 |
| 15 | | | | | | | | | |

| Line No. | BILL UNDER PROPOSED RATES (10) BASE RATE | (11) FUEL CHARGE | (12) ECCR CHARGE | (13) CAPACITY CHARGE | (14) ECRC CHARGE | (15) GRT CHARGE | (16) TOTAL | INCREASE (17) DOLLARS (16)-(9) | (18) PERCENT (17)/(9) | COSTS IN CENTS/KWH (19) PRESENT (9)/(2)*100 | (20) PROPOSED (16)/(2)*100 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | $ 859.86 | $ 293.35 | $ 20.59 | $ 6.90 | $ 42.27 | $ 31.36 | $ 1,254.32 | $ 69.63 | 5.9% | 10.82 | 11.45 |
| 2 | $ 1,306.35 | $ 513.36 | $ 60.75 | $ 20.25 | $ 73.97 | $ 50.66 | $ 2,027.36 | $ 123.25 | 6.5% | 9.94 | 10.58 |
| 3 | $ 1,548.43 | $ 880.05 | $ 60.75 | $ 20.25 | $ 126.80 | $ 67.60 | $ 2,703.86 | $ 84.36 | 3.2% | 7.97 | 8.23 |
| 4 | $ 1,769.15 | $ 1,313.30 | $ 60.75 | $ 20.25 | $ 190.20 | $ 86.50 | $ 3,460.16 | $ 36.79 | 1.1% | 6.95 | 7.02 |
| 5 | | | | | | | | | | | |
| 6 | $ 5,844.01 | $ 1,955.87 | $ 137.24 | $ 45.99 | $ 281.78 | $ 204.22 | $ 8,168.91 | $ 464.21 | 6.0% | 10.55 | 11.19 |
| 7 | $ 8,533.96 | $ 3,422.42 | $ 405.00 | $ 135.00 | $ 493.12 | $ 333.06 | $ 13,322.56 | $ 821.67 | 6.6% | 9.79 | 10.43 |
| 8 | $ 10,134.60 | $ 5,867.01 | $ 405.00 | $ 135.00 | $ 845.34 | $ 445.82 | $ 17,832.67 | $ 562.43 | 3.3% | 7.89 | 8.14 |
| 9 | $ 11,739.31 | $ 8,755.35 | $ 405.00 | $ 135.00 | $ 1,268.01 | $ 571.86 | $ 22,874.53 | $ 245.26 | 1.1% | 6.89 | 6.96 |
| 10 | | | | | | | | | | | |
| 11 | $ 22,076.32 | $ 7,822.66 | $ 646.96 | $ 183.96 | $ 1,127.12 | $ 814.33 | $ 32,673.37 | $ 1,956.82 | 6.0% | 10.52 | 11.16 |
| 12 | $ 34,038.16 | $ 13,689.60 | $ 1,620.00 | $ 540.00 | $ 1,972.46 | $ 1,329.70 | $ 53,188.03 | $ 3,286.70 | 6.6% | 9.77 | 10.41 |
| 13 | $ 40,436.26 | $ 23,466.04 | $ 1,620.00 | $ 540.00 | $ 3,381.36 | $ 1,780.71 | $ 71,226.39 | $ 2,249.72 | 3.3% | 7.87 | 8.13 |
| 14 | $ 46,857.52 | $ 35,021.30 | $ 1,620.00 | $ 540.00 | $ 5,072.04 | $ 2,284.89 | $ 91,395.84 | $ 981.03 | 1.1% | 6.88 | 6.96 |
| 15 | | | | | | | | | | | |

16

| Line No. | | PRESENT GSD | PRESENT GSDT | | PRESENT GSD OPT. | | PROPOSED GSD | PROPOSED GSDT | | PROPOSED GSD OPT. | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 17 | | | | | | | | | | | |
| 18 | | | | | | | | | | | |
| 19 | CUSTOMER CHARGE | 33.24 | 33.24 | $/Bill | 33.24 | $/Bill | 33.24 | 33.24 | | 33.24 | $/Bill |
| 20 | DEMAND CHARGE | 10.25 | - | $/KW | - | $/KW | 12.52 | - | $/KW | - | $/KW |
| 21 | BILLING | - | 3.46 | $/KW | - | $/KW | - | 4.22 | $/KW | - | $/KW |
| 22 | PEAK | - | 6.79 | $/KW | - | $/KW | - | 8.29 | $/KW | - | $/KW |
| 23 | ENERGY CHARGE | 1.754 | - | ¢/KWH | 6.660 | ¢/KWH | 1.754 | - | ¢/KWH | 7.549 | ¢/KWH |
| 24 | ON-PEAK | - | 3.211 | ¢/KWH | - | ¢/KWH | - | 3.211 | ¢/KWH | - | ¢/KWH |
| 25 | OFF-PEAK | - | 1.159 | ¢/KWH | - | ¢/KWH | - | 1.159 | ¢/KWH | - | ¢/KWH |
| 26 | FUEL CHARGE | 2.956 | - | ¢/KWH | 2.956 | ¢/KWH | 2.679 | - | ¢/KWH | 2.679 | ¢/KWH |
| 27 | ON-PEAK | | 3.166 | ¢/KWH | - | ¢/KWH | | 2.870 | ¢/KWH | - | ¢/KWH |
| 28 | OFF-PEAK | | 2.865 | ¢/KWH | - | ¢/KWH | | 2.597 | ¢/KWH | - | ¢/KWH |
| 29 | CONSERVATION CHARGE | 0.77 | 0.77 | $/KW | 0.180 | ¢/KWH | 0.81 | 0.81 | $/KW | 0.188 | ¢/KWH |
| 30 | CAPACITY CHARGE | 0.27 | 0.27 | $/KW | 0.063 | ¢/KWH | 0.27 | 0.27 | $/KW | 0.063 | ¢/KWH |
| 31 | ENVIRONMENTAL CHARGE | 0.386 | 0.386 | ¢/KWH | 0.386 | ¢/KWH | 0.386 | 0.386 | ¢/KWH | 0.386 | ¢/KWH |

32
33 Notes:
34 A. The kWh for each kW group is based on 20, 35, 60, and 90% load factors (LF).
35 B. Charges at 20% LF are based on the GSD Option rate; 35% and 60% LF charges are based on the standard rate; and 90% LF charges are based on the TOD rate.
36 C. All calculations assume meter and service at secondary voltage.
37 D. TOD energy charges assume 25/75 on/off-peak % for 90% LF. Peak demand to billing demand ratios are assumed to be 90% at 90% LF.
38 E. Cost recovery clause factors are the current 2017 factors.
39

Supporting Schedules: E-13c, E-14 Supplement

Recap Schedules:

SOBRA
12CP and 1/13 with 40% Allocation to Lighting
All Demand

August 15, 2017



FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: For each rate, calculate typical monthly bills for present rates and proposed rates.

Type of data shown:
XX Projected Test year Ended 12/31/2017

COMPANY: TAMPA ELECTRIC COMPANY

## IS - INTERRUPTIBLE SERVICE

RATE SCHEDULE IS-1

| Line No. | (1) TYPICAL KW | (2) TYPICAL KWH | BILL UNDER PRESENT RATES (3) BASE RATE | (4) CCV CREDIT | (5) FUEL CHARGE | (6) ECCR CHARGE | (7) CAPACITY CHARGE | (8) ECRC CHARGE | (9) GRT CHARGE | (10) TOTAL | BILL UNDER PROPOSED RATES (11) BASE RATE | (12) CCV CREDIT | (13) FUEL CHARGE | (14) ECCR CHARGE | (15) CAPACITY CHARGE | (16) ECRC CHARGE | (17) GRT CHARGE | (18) TOTAL | INCREASE (19) DOLLARS (18)-(9) | (20) PERCENT (17)/(9) | COSTS IN CENTS/KWH (21) PRESENT (9)/(2)*100 | (22) FINAL (18)/(2)*100 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 500 | 127,750 | $ 6,038 | $ (1,729.00) | $ 3,737.97 | $ 240.00 | $ 70.00 | $ 479.06 | $ 201 | $ 8,037 | $ 6,066 | $ (1,772.75) | $ 3,387.93 | $ 250.00 | $ 70.00 | $ 479.06 | $ 217.40 | $ 8,699.63 | $ 683 | 8.2% | 8.29 | 6.81 |
| 2 | 500 | 219,000 | $ 7,589 | $ (2,984.00) | $ 6,407.94 | $ 240.00 | $ 70.00 | $ 821.25 | $ 311 | $ 12,456 | $ 8,590 | $ (3,039.00) | $ 5,807.88 | $ 250.00 | $ 70.00 | $ 821.25 | $ 320.75 | $ 12,830.05 | $ 374 | 3.0% | 5.69 | 5.86 |
| 3 | 500 | 328,500 | $ 10,607 | $ (4,448.00) | $ 9,580.99 | $ 240.00 | $ 70.00 | $ 1,231.88 | $ 443 | $ 17,706 | $ 11,637 | $ (4,558.50) | $ 8,687.47 | $ 250.00 | $ 70.00 | $ 1,231.88 | $ 443.63 | $ 17,741.07 | $ 35 | 0.2% | 5.39 | 5.40 |
| 4 | | | | | | | | | | | | | | | | | | | | | | |
| 5 | 1,000 | 255,500 | $ 9,387 | $ (3,458.00) | $ 7,475.93 | $ 480.00 | $ 140.00 | $ 958.13 | $ 384 | $ 15,367 | $ 11,447 | $ (3,545.50) | $ 6,775.86 | $ 500.00 | $ 140.00 | $ 958.13 | $ 417.31 | $ 16,892.46 | $ 1,326 | 8.6% | 6.01 | 6.53 |
| 6 | 1,000 | 438,000 | $ 14,449 | $ (5,928.00) | $ 12,815.88 | $ 480.00 | $ 140.00 | $ 1,642.50 | $ 605 | $ 24,205 | $ 16,809 | $ (6,078.00) | $ 11,615.75 | $ 500.00 | $ 140.00 | $ 1,642.50 | $ 623.63 | $ 24,953.32 | $ 749 | 3.1% | 5.53 | 5.70 |
| 7 | 1,000 | 657,000 | $ 20,524 | $ (8,892.00) | $ 19,121.98 | $ 480.00 | $ 140.00 | $ 2,463.75 | $ 868 | $ 34,706 | $ 22,584 | $ (9,117.00) | $ 17,334.95 | $ 500.00 | $ 140.00 | $ 2,463.75 | $ 869.36 | $ 34,776.37 | $ 70 | 0.2% | 5.28 | 5.29 |
| 8 | | | | | | | | | | | | | | | | | | | | | | |
| 9 | 5,000 | 1,277,500 | $ 44,177 | $ (17,290.00) | $ 37,379.65 | $ 2,400.00 | $ 700.00 | $ 4,790.63 | $ 1,850 | $ 74,007 | $ 54,477 | $ (17,727.50) | $ 33,879.30 | $ 2,500.00 | $ 700.00 | $ 4,790.63 | $ 2,015.66 | $ 80,635.28 | $ 6,628 | 9.0% | 5.79 | 6.31 |
| 10 | 5,000 | 2,190,000 | $ 69,490 | $ (29,640.00) | $ 64,079.40 | $ 2,400.00 | $ 700.00 | $ 8,212.50 | $ 2,956 | $ 118,197 | $ 79,790 | $ (30,390.00) | $ 58,078.60 | $ 2,500.00 | $ 700.00 | $ 8,212.50 | $ 3,048.48 | $ 121,939.49 | $ 3,743 | 3.2% | 5.40 | 5.57 |
| 11 | 5,000 | 3,285,000 | $ 99,885 | $ (44,460.00) | $ 95,609.93 | $ 2,400.00 | $ 700.00 | $ 12,318.75 | $ 4,268 | $ 170,701 | $ 110,166 | $ (45,585.00) | $ 86,874.73 | $ 2,500.00 | $ 700.00 | $ 12,318.75 | $ 4,278.24 | $ 171,049.72 | $ 349 | 0.2% | 5.20 | 5.21 |

| Line No. | | PRESENT IS | PRESENT IST | | PROPOSED IS | PROPOSED IST | |
|---|---|---|---|---|---|---|---|
| 12 | | | | | | | |
| 13 | | | | | | | |
| 14 | | | | | | | |
| 15 | CUSTOMER CHARGE | 689.11 | 689.11 | $/Bill | 689.11 | 689.11 | $/Bill |
| 16 | DEMAND CHARGE | 1.61 | 1.61 | $/KW | 3.67 | 3.67 | $/KW |
| 17 | PEAK DEMAND CHARGE | - | - | $/KW | - | - | $/KW |
| | ENERGY CHARGE | 2.774 | | ¢/KWH | 2.774 | - | ¢/KWH |
| 18 | ON-PEAK ENERGY CHARGE | - | 2.774 | ¢/KWH | - | 2.774 | ¢/KWH |
| 19 | OFF-PEAK ENERGY CHARGE | - | 2.774 | ¢/KWH | - | 2.774 | ¢/KWH |
| 20 | DELIVERY VOLTAGE CREDIT | - | - | $/KW | - | - | $/KW |
| 21 | FUEL CHARGE | 2.926 | - | ¢/KWH | 2.652 | - | ¢/KWH |
| 22 | ON-PEAK | - | 3.194 | ¢/KWH | - | 2.941 | ¢/KWH |
| 23 | OFF-PEAK | - | 2.836 | ¢/KWH | - | 2.571 | ¢/KWH |
| 24 | CONSERVATION CHARGE | 0.48 | 0.48 | $/KW | 0.50 | 0.50 | $/KW |
| 25 | CAPACITY CHARGE | 0.14 | 0.14 | $/KW | 0.14 | 0.14 | $/KW |
| 26 | ENVIRONMENTAL CHARGE | 0.375 | 0.375 | ¢/KWH | 0.375 | 0.375 | ¢/KWH |
| 27 | | | | | | | |
| 28 | GSLM-2 CONTRACT CREDIT VALUE | (9.88) | (9.88) | $/kW | (10.13) | (10.13) | $/kW |
| 29 | | | | | | | |

30 Notes:
31 A. The kWh for each kW group is based on 35, 60, and 90% load factors (LF).
32 B. Charges at 35% and 60% LF are based on standard rates and charges at 90% LF are based on TOD rates. Peak demand to billing demand ratios are assumed to be 98% at 90% LF.
33 C. Calculations assume meter and service at primary voltage and a power factor of 85%.
34 D. TOD energy charges assume 25/75 on/off-peak % for 90% LF.
35 E. CCV credits in columns 5 and 12 are load-factor adjusted and reflect service at primary voltage.
36 F. Cost recovery clause factors are the current 2017 factors.
37 G. The present GSLM-2 Contract Credit Value represents the 2012 factor which is currently locked-in by all IS customers. The proposed GSLM-2 Contract Credit Value for 2017 is expected to be
38 locked-in by all IS customers as it becomes effective.
39