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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20240026-EI

Petition for rate increase by Tampa Electric Company.
_______________________________________/

DOCKET NO. 20230139-EI

Petition for approval of 2023 depreciation and dismantlement study, by Tampa Electric Company.
_______________________________________/

DOCKET NO. 20230090-EI

In re: Petition to implement 2024 generation base rate adjustment provisions in paragraph 4 of the 2021 stipulation and settlement agreement, by Tampa Electric Company.
_______________________________________/

VOLUME 11 - PAGES 2398 - 2665

PROCEEDINGS: HEARING

COMMISSIONERS PARTICIPATING: CHAIRMAN MIKE LA ROSA
COMMISSIONER ART GRAHAM
COMMISSIONER GARY F. CLARK
COMMISSIONER ANDREW GILES FAY
COMMISSIONER GABRIELLA PASSIDOMO

DATE: Thursday, August 29, 2024

TIME: Commenced: 8:00 a.m.
Concluded: 7:00 p.m.

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

TRANSCRIBED BY: DEBRA R. KRICK
Court Reporter and
Notary Public in and for
the State of Florida at Large

APPEARANCES: (As heretofore noted.)

I N D E X

EXHIBITS

NUMBER:		ID	ADMITTED
60-62	As identified in the CEL		2491
113-132	As identified in the CEL		2558
72-76	As identified in the CEL		2644
784-787	As identified in the CEL		2644
77-81	As identified in the CEL		2663

P R O C E E D I N G S

(Transcript follows in sequence from Volume 10.)

CHAIRMAN LA ROSA: Mr. Ostrander, I presume?

Yes.

Whereupon,

BION C. OSTRANDER

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

THE WITNESS: I do.

CHAIRMAN LA ROSA: Excellent. Thank you.

MR. REHWINKEL: Thank you, Mr. Chairman. The Public Council calls Bion Ostrander to the stand.

EXAMINATION

BY MR. REHWINKEL:

Q Mr. Ostrander, could you state your name for the record?

A Bion C. Ostrander.

Q And, Mr. Ostrander, by whom are you employed, and on whose behalf are you appearing today?

A I am employed and owner of Ostrander Consulting, and I am appearing today on behalf of the OPC.

Q Mr. Ostrander, did you cause to be prepared 78

pages of responsive direct prefiled testimony in this case?

A Yes.

Q Do you have any corrections to make to that testimony?

A I do have some corrections.

Q Could you give that -- read those into the record today?

A Yes. These are all minor typographical errors and do not change the meaning or intent of my direct testimony.

First of all, at master page 2201. Footnote 17 is incomplete. If you look at the very end, where it says POD No., there is no number there. That number should be 34. So it should be POD No. 34 to complete that footnote.

Turning now to master page 2205, you will see that footnote 27 has been struck through and duplicated. The strike-through footnote is essentially the same as the other footnote that exists. The word processing should have deleted that entire strike-through reference. So you could ignore that strike-through footnote.

Turning to page 2210, footnote 29, on the second line, you can strike the word "in" that follows the word "this". And so that second sentence reads: Affiliate transaction rules given the previous Florida rule exemptions, comma, and I have repeated this term in Rule 25, dash.

And most importantly, on the very last line of that footnote, it refers to Rule 25-6.1352. In both places the 1352 is incorrect, and in both instances should be replaced with 1351. And the 1351 is cited in the body of my testimony at that same page of the testimony.

Next, going to page 2219, at line 15, change the reference to headcount allocation to purchase order spend. So that entire line on 15 reads: Impacted by the increased purchase order spend factor for TECO.

Turning to the next page -- master page, 2220, line, 17. Insert a D behind the word centralize, so it is centralized.

Next, turning to master page 2237, on line five, strike the word "for" that appears after the word "necessary". And also on this same page, at line 13, after the word "indicates", insert the word "it".

And finally, on master page 2249, at lines 22 and 23 of that page, and the following page, lines one to 10, those are underlined, but there is no reason to have those underlined. It's not intended to call any emphasis to those words. It was just an error in having those words underlined.

Q Mr. Ostrander, with those corrections to your testimony, if I ask you the questions contained in your testimony today, would your answers be the same?

A Yes.

MR. REHWINKEL: Mr. Chairman, I would ask that Mr. Ostrander's prefiled direct testimony be inserted into the record as though read.

CHAIRMAN LA ROSA: Okay.

(Whereupon, prefiled direct testimony of Bion C. Ostrander was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Rate Increase by Tampa Electric Company ______________________________________/	Docket No. 20240026-EI Filed: June 6, 2024

DIRECT TESTIMONY

OF

BION C. OSTRANDER

ON BEHALF

OF

THE CITIZENS OF THE STATE OF FLORIDA

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TABLE OF CONTENTS

DIRECT TESTIMONY

OF

BION C. OSTRANDER

On Behalf of the Citizens of the State of Florida

Before the

Florida Public Service Commission

Docket No. 20240026-EI

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Bion C. Ostrander. I am an independent regulatory consultant and President of Ostrander Consulting with a business address of 1121 S.W. Chetopa Trail, Topeka, Kansas 66615.

Q. PLEASE DESCRIBE OSTRANDER CONSULTING.

A. Ostrander Consulting performs regulatory consulting work primarily for U.S. and international state regulatory agencies and governmental entities, and have operated for thirty-three years since 1990. I have forty-four years of combined regulatory, CPA firm, and accounting experience and have extensive experience in the utility regulatory field as an expert witness in over 300 regulatory proceedings, including electric, gas, renewable energy, water/sewer, telephone utilities and other special projects.

Q. HAVE YOU PREPARED AN EXHIBIT WHICH DESCRIBES YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE?

A. Yes. I have attached Exhibit BCO-1, which is a summary of my background, experience and qualifications.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE FLORIDA PUBLIC COMMISSION AS AN EXPERT WITNESS?

A. Yes. I provided testimony before the Florida Public Service Commission ("Commission" or "FPSC") on behalf of the Office of Public Counsel in Docket No. 030867-TI, regarding telecommunications access charge matters.

Q. BY WHOM WERE YOU RETAINED, AND WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I was retained by the Florida Office of Public Counsel ("OPC") to review the impact of affiliate transactions and the spin-off of Peoples Gas System, Inc. ("PGS") upon the revenue requirements of Tampa Electric Company, Inc. ("TECO") in this rate case, along with proposing any necessary adjustments.

Q. ARE OTHER OPC WITNESSES INCORPORATING YOUR PROPOSED REVENUE REQUIREMENT ADJUSTMENTS?

A. Yes. OPC witness Mr. Lane Kollen will incorporate the impacts of my adjustments in his final revenue requirement recommendation.

II. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR TESTIMONY AND RECOMMENDATIONS.

A. Affiliate transactions require greater scrutiny due to the inherent influential nature of these transactions from both a financial and policy perspective. Although much of the transactions are not *per se* unreasonable, it is always the utility's burden to prove its requested costs are reasonable. To ensure that affiliate transactions are properly accounted for so that potential utility nonregulated costs (allocated from parent company or other nonregulated affiliates) are not subsidized by regulated-utility ratepayers, my review consists of a comprehensive evaluation of affiliate costs charged to and from TECO and various affiliated companies. I have reviewed or attempted to review all cost allocation manuals, all shared asset and services agreement, if any, among and between affiliate companies, the inputs utilized to derive its Modified Massachusetts Method ("MMM") for allocation, and other statistical inputs and drivers used for allocation purposes. Based on this comprehensive review, I have identified areas where TECO has failed to provide supporting documentation for various types of allocated costs and where certain allocation factors warrant adjustments.

Q. PLEASE SUMMARIZE THE ADJUSTMENTS YOU ARE RECOMMENDING.

A. I am recommending the following adjustments in the body of my testimony, as well as the rationale for the adjustments.

1) I am recommending an expense reduction of $858,561 to reflect a decrease in corporate support allocations from Emera to TECO related to expenses of a dissolved affiliate that were proposed to be transferred to TECO.

C23-2190

2) I am recommending an expense reduction of $5,457,472 to reflect a decrease in shared service allocations from Tampa Electric to TECO related to: a) revising allocation factors for various shared services; and 2) disallowing one-half of significant unsupported corporate overhead costs.

Q. CAN YOU PROVIDE AN OVERVIEW OF YOUR PROCESS FOR REVIEWING AFFILIATE TRANSACTIONS IN GENERAL AND IN THIS CASE?

A. Yes, I can. Affiliate transactions are difficult, complex, and time consuming to review. The review of affiliate transactions also requires timely, complete, and organized responses from the utility, especially in the relatively compressed time period for filing Intervenor testimony in this case. I have concerns with the timelines and quality of responses from TECO, but I do not want that to be the focus of my testimony. However, substantial cooperation from the utility is necessary in order to isolate significant issues of concern regarding costs that may not have much immediate or easily obtained supporting documentation because the amounts are allocated (or direct assigned) from the parent company or another affiliate.

It is possible to review the reasonableness of the allocation methods and factors (and inputs to those methods) to some degree, and to quantify concerns in related adjustments, and I have performed this task as part of my $6.30 million total adjustment to affiliate transactions.

However, the two most difficult issues to address and quantify are regarding affiliate transactions and the allocation of corporate overhead/indirect allocation costs

C23-2191

to the regulated utility from a parent company and from a centralized service company. In the instant case, Tampa Electric/TECO acts as a *de facto* centralized service provider, which complicates the evaluation of its allocations to the regulated operations of TECO. The evaluation of affiliate transactions raises the following concerns:

1) Are there duplicative unsupported overhead/indirect costs; and
2) Whether costs are reflected at the lower of cost or market value for allocations from affiliates to TECO

First, when I refer to the issue of "duplicative" costs, I am concerned that a parent company or the regulated utility may intentionally or unintentionally allocate/assign primarily indirect/overhead-type costs to the regulated utility. For example, at both the corporate level and regulated utility level, certain employees may provide various services related to human resources, financial/accounting, legal, procurement, or overall administrative services (officers/executives providing oversight at both levels).

However, it is difficult to determine if some portion of these types of service costs are necessary and duplicative of each other and if they are directly (or even indirectly) related to and provide benefits to the regulated utility operations. For example, in most cases, almost all corporate level costs are allocated down to regulated and unregulated operations, but there is a concern whether some of these high-level costs are truly beneficial to the regulated utility or just merely supporting and promoting the broad corporate structure.

It is extremely difficult to determine the optimal or most efficient production of services and level of employees to provide these services at both the corporate and regulated utility level. It is almost impossible to specifically determine what each employee, or even each department, is doing that is directly or even indirectly beneficial to the regulated utility, and if the costs should be allocated to the regulated utility (and even to unregulated affiliates) – unless a very detailed and time consuming evaluation is performed (and even that would require complete cooperation from the company).

However, when broad, undefined, and aggregated significant buckets of costs are allocated to the regulated utility, this raises concerns about "duplicate" or more generic unsupported costs. For example, in this case Tampa Electric allocated to TECO a category of expenses cited as "Corporate Responsibility" consisting of total 2025 Budget[1] expenses of $10.60 million, of which $7.60 million is allocated to TECO (15% of the total $51.80M expenses allocated from Tampa Electric to TECO). I have disallowed one-half of the $7.60 million of expenses due to the absence of underlying supporting documentation and calculations for this broad level of expenses.

Second, I am concerned that costs allocated/assigned to TECO from the parent or Tampa Electric be reflected at the lower of cost or market (or fair market value). I am aware that technically, Florida rules do not require that parent company or centralized service company allocations to TECO be at the lower of cost or market. However, when I use the term "lower of cost or market" I am using this term in more of a common sense application, such that no entity should be allowed to allocate/assign costs to TECO (or any affiliate) that are unreasonable, excessive, and duplicative. Also, these costs should be in line with the market and be competitively priced, although

[1] The "2025 Budget" costs are the costs included in this rate case by TECO for determination of the revenue requirement to support the proposed rate increase.

market value is difficult to determine for a specific service/department without a very complex and time consuming analysis. Also, when I refer to services being provided at some reasonable level of "cost," I am not asserting or implying that the parent company or TECO deliberately mark-up (or include an additive fee) labor or other service costs allocated/assigned to TECO. My concern is that "cost" should not be excessive and should not include the costs of more employees (and related overhead costs) than what is necessary to provide that centralized or shared service, and this returns to my concern with duplicative costs.

As an example, in 2023, affiliate PGS took back some Procurement services in-house, and stopped taking some portion of these services allocated to them from centralized service provider Tampa Electric/TECO. It is possible that PGS made a competitive-market decision, and determined that the centralized service provider's cost of this Procurement service was excessive or exceeded fair market (or fair value). However, TECO now essentially pays for almost all of the Procurement costs[2] provided by centralized service provider, TECO. This is not fair or reasonable, and is a negative fall-out of monopoly practices and being a captive customer to the centralized service provider that is also the primary regulated utility in this rate case. These and other related affiliate transaction concerns are addressed in my direct testimony.

III. EXPLANATION OF CORPORATE STRUCTURE

Q. PLEASE DESCRIBE THE TECO AND EMERA, INC. ("EMERA" OR "PARENT COMPANY") CORPORATE STRUCTURE.

[2] Also, these Procurement costs are increasing at an alarming level.

A. TECO is a public utility operating within the state of Florida, it is comprised of an electric division, referred to as Tampa Electric. Most of my testimony refers to TECO, although I may also refer to TECO and/or the electric division of Tampa Electric when addressing the allocation of costs from Tampa Electric to TECO and other affiliates. Sometimes my testimony will use TECO and Tampa Electric interchangeably, and I do not intend any important distinction in these instances. All of TECO's common stock is owned by TECO Energy, Inc., a holding company, that is also an indirect, wholly owned subsidiary of Emera.

TECO previously included a natural gas division, but on January 1, 2023, TECO transferred the assets and liabilities of the gas division into a separate corporation called PGS, which is a wholly owned subsidiary of a newly formed gas operations holding company, TECO Gas Operations, Inc., a wholly owned subsidiary of TECO Energy, Inc.

Emera, Inc.[3] is based in Halifax, Nova Scotia, and owns and operates cost-of-service rate regulated electric and gas utilities in Canada, the United States ("U.S."), and the Caribbean consisting of the following:[4]

1) Nova Scotia Power Inc. ("NSP");
2) TECO;
3) PGS;
4) New Mexico Gas Company, Inc. ("NMG");
5) Emera Brunswick Pipeline Company Limited ("Brunswick Pipeline");

[3] Emera also owns equity investments in NSP Maritime Link Inc. ("NSPML"), Labrador Island Link Limited Partnership ("LIL"), Maritimes & Northeast Pipeline Limited Partnership and Maritimes & Northeast Pipeline, LLC ("M&NP"), and St. Lucia Electric Services Limited ("Lucelec").
[4] Emera 2023 Annual Report, p. 10.

6) Barbados Light & Power Company Limited ("BLP"); and
7) Grand Bahama Power Company Limited ("GBP").

In addition to the entities listed above, there are about 238 other Emera affiliates as of 2022, too numerous to list.[5]

A high level Corporate Structure organization chart for 2023 is included in this rate proceeding at TECO's Schedule No. C-31, page 22 of 35. A more detailed Corporate Structure chart (by detailed affiliates) with 13 pages has also been provided by TECO.[6]

IV. EXPLANATION OF COST ALLOCATION MANUALS ("CAM") AND ALLOCATION PROCESS

Q. PLEASE EXPLAIN THE VARIOUS CAMs.

A. There are three different CAMs that have some application to this proceeding:

1) November 20, 2023, NSP CAM – TECO states this CAM should be relied upon regarding allocations from Emera to TECO (and affiliates);
2) January 1, 2020, TECO Energy, Inc. CAM – this CAM addresses allocations from TECO to affiliates (through the period ending December 31, 2023); and
3) January 1, 2024, TECO Holdings, inc. CAM – this CAM replaces the January 1, 2020, TECO Energy, Inc. CAM.

There are two primary changes that took place with the new TECO Holdings, inc. CAM effective January 1, 2024, replacing the prior TECO Energy, Inc. CAM of

[5] Nova Scotia Utility and Review Board, NS Power Affiliate Code of Conduct, 2022 Report, April 27, 2023, Redacted, Appendix A, pp. 2-52 (provided in TECO's response to OPC's Second Request for Production of Documents ("POD"), No. 44).
[6] TECO's response to OPC's First Set of POD No. 22, Bates Stamp ("BS") pages 11041 to 11054.

January 1, 2020. First, effective April 1, 2024, TECO Energy, Inc. ceased to exist and was replaced by TECO Holdings, inc. TECO Holdings, inc. now operates the companies consisting of the prior TECO Energy, Inc. entities of TECO, PGS, NMG, plus SeaCoast.[7]

Second, effective January 1, 2023, TECO transferred the assets and liabilities of its PGS division into a separate corporation called PGS. This did not impact the allocations process, TECO continues to allocate expenses to the new PGS corporation as it did to the prior PGS division,[8] generally using the same allocation methods. Other than the January 1, 2024, TECO Holdings, inc. CAM replacing the January 1, 2020, TECO Energy, Inc. CAM, the corporate structure and provision of centralized services by Tampa Electric/TECO to affiliates remains about the same. The Federal Energy Regulatory Commission ("FERC") waiver (effective January 1, 2020 and discussed below), is still operative and the January 1, 2024, TECO Holdings, inc. CAM has been used by TECO for determining the 2024/2025 budgeted affiliate expenses in the revenue requirement of this proceeding.

TECO states the November 30, 2023, NSP CAM should be relied upon regarding Corporate Support Services and Management and Administrative Services expenses (and other expenses) allocated from Emera to TECO (and other affiliates of previous TECO Energy, Inc. and current TECO Holdings, inc.) for this proceeding.[9] I do have some concerns with relying on the NSP CAM as a surrogate for allocations from Emera to TECO (and U.S. affiliates) in this proceeding.

[7] TECO Holding, inc. operates within the Emera US Holdings Inc. group of Emera companies.
[8] Although PGS has taken some shared services back from TECO and performs these services in-house instead of receiving an allocation of these costs from TECO.
[9] Provided by TECO to OPC via an April 10, 2024 email.

Q. PLEASE EXPLAIN YOUR CONCERNS REGARDING THE USE OF THE NSP CAM AS A SURROGATE FOR AN EMERA CAM IN THIS PROCEEDING.

A. First, I have reservations about using the NSP CAM as the guide (or surrogate guide) for allocations from Emera to TECO (and other U.S. affiliates) in this proceeding, when the NSP CAM is not specifically named or mentioned as an Emera CAM. Technically, the NSP CAM describes the types of Corporate Support and Management and Administrative Service expenses and methods used to allocate and direct assign expenses from the largest Canadian affiliate, NSP, to other affiliates,[10] but it does not specifically address the allocation or direct assignment of service expenses from Emera to TECO and other U.S. affiliates. In fact, the NSP CAM does not even mention or refer to parent company Emera (other than being included at the list of "Affiliates" at Section 2.0).

Second, a TECO-prepared workpaper that was intended to reconcile the 2023 FERC Form 1 affiliate diversification data identifies: 1) $11.10 million of Emera "Corporate Support Services" charged to TECO; and 2) this same workpaper identifies ($4.10 million) of Emera Energy Services, Inc. "Asset Management Agreement" services treated as a debit to Accounts Receivable on TECO's books (although not booked to an expense account).[11]

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[10] Although the NSP CAM may also be relied upon by NSP or Emera to describe the Corporate Support and M&A service expenses and methods used to allocate and direct assign expenses from Emera to NSP, the CAM does not specifically mention that it is a guide for Emera allocating and direct assigning expenses from Emera to NSP or TECO.

[11] This information is provided at TECO's response to OPC's Fifth Set of Interrogatories and PODs, Interrogatory No. 98 and POD No. 74, and Excel schedule POD 74 titled "OPC_Affiliate_Purchases by FERC." This information was originally provided by TECO in response to OPC's Second Set of Interrogatories and PODs, Interrogatory No. 61 and POD No. 37, and Excel spreadsheet at POD 37 and was intended to reconcile TECO's FERC Form 1 affiliate diversification data.

However, TECO has not provided an Emera Corporate Support Services agreement (to the extent a separate agreement exists) or related documentation and calculations supporting the direct expenses of $7.18 million that are included in the $11.10 million of Emera charges to TECO. Also, TECO has not provided the supporting documentation for the Emera Energy Services, Inc.'s Asset Management Agreement. Thus, I would recommend the following in this regard:

1) First, a new specific and updated "Emera CAM" should be created that explains and governs specific affiliate transactions, including allocated and direct-assigned expenses from Emera to TECO and all other affiliates;
2) Second, the updated Emera CAM should identify all Corporate Support Services and Management and Administrative Services to be allocated and direct assigned from Emera to TECO and all other affiliates, and specific copies of all agreements (such as a Corporate Support Service agreements and Management and Administrative Services agreement) should be attached to the Emera CAM as exhibits or appendices; and
3) Third, the updated Emera CAM should identify all Asset Management Agreement services to be allocated and direct assigned from Emera Energy Services, Inc. to TECO and all other affiliates, and specific copies of all agreements (such as the Asset Management Agreement) should be attached to the Emera CAM as exhibits or appendixes. Examples of supporting documentation and calculations for these expenses should be included in the Emera CAM.

The above concerns will also be addressed in the adjustments section of my testimony.

C23-2199

Additionally, the details of the January 1, 2020, TECO Energy, Inc. CAM and the subsequent January 1, 2024, TECO Holdings, inc. CAM will be addressed in more detail in the following questions that address allocation processes.

Q. PLEASE IDENTIFY THE AFFILIATES THAT ALLOCATE OR ASSIGN EXPENSES TO TECO IN 2023.

A. I have summarized those primary affiliate expense charges to TECO in 2023 (excluding gas purchases).[12] The expenses charged from affiliates to TECO are: a) direct assigned; and b) indirect allocated/assessed which are relevant to my review in this rate case because some of these amounts are "affiliate" transactions subject to my review.

1) **Emera** - Emera charged certain direct and allocated corporate support service expenses to TECO in 2023 of $14.50 million, and this includes $11.10 million of direct/allocated Corporate Support Services and $3.70 million of labor.[13]

2) **Emera Energy Services, Inc**. – Emera Energy Services, Inc. appears to charge TECO for certain services under its Asset Management Agreement,[14] but TECO has not provided supporting documentation and detailed calculations for these charges. However, it appears TECO has only disclosed the "net impact" of transactions with Emera Energy Services, Inc. which is a $4.10 million net TECO charge (via an Accounts Receivable entry) to Emera Energy Services, Inc. in 2023 (and a 2024/2025 Budget amount of $4.40 million). However, this net charge from TECO to Emera Energy Services, Inc. of $4.10 million is

[12] I did not review "gas purchase" affiliate transactions, my review focused on operating expenses and corporate overhead/common expenses allocated or direct assigned from affiliates to TECO.

[13] The $11.10 Million of Corporate Support Services charged to TECO includes $7.11 Million of direct-assigned services, $3.04 Million of allocated services, $.89 Million of allocated TECO Services, Inc. charges (assigned to TECO), and $.07 Million of miscellaneous. This information is from TECO's response to OPC's Tenth Set of Interrogatories (some Interrogatories are Confidential) and Eleventh Set of PODs, Confidential response to Interrogatory No.179 and POD No. 138. POD No. 138, Excel spreadsheet "(BS 30600) OPC Summary – POD 138.xlsx" is not Confidential. This Excel spreadsheet shows a reconciliation from Emera amounts allocated to TECO that are in Canadian currency at TECO's response to OPC's Second Set of Interrogatories and PODs, Interrogatory No. 61 and POD No. 37, Excel spreadsheet titled, "Confidential (BS 16846) Emera Affiliate Allocations – Annual Summary 2023_Highlighted.xlsx." The high level total amounts allocated to TECO are not considered to be Confidential because these amounts are disclosed in other Interrogatories and PODs, the detailed allocated amounts by Function and for other affiliates is considered to be Confidential.

[14] A summary description of the Asset Management Agreement indicates that Emera Energy Services, Inc. provides services to TECO such as Facility Management, Telecommunications, Environmental, Regulatory, Customer Service, Fuels, Government Community Affairs, Engineering, O&M Safety Training, and Other.

confusing, because it does not disclose possible underlying transactions regarding charges from Emera Energy Services, Inc. to TECO under the Asset Management Agreement. This concern will be addressed later in more detail.

3) **TECO** - Tampa Electric incurred $96.20 million of allocated and direct assigned expenses on its books for 2023 ($72.80 million of allocated expenses and $23.40 million of direct assigned expenses). Tampa Electric/TECO treated these expenses in the following manner: a) Tampa Electric allocated $22.20 million of the total $72.80 million of allocable expenses to affiliates and $50.60 million was retained on TECO books; and b) Tampa Electric direct assigned $5.80 million of the total $23.40 million of direct-assigned expenses to affiliates and retained $17.60 million on TECO books.[15] I have treated the $50.60 million of "allocated" expenses retained on TECO's books as being subject to my affiliate transaction review, because the total allocable expenses of $72.80 million were subject to allocation between TECO and affiliates using the MMM factor and other statistical allocation factors (headcount, claims, etc.).[16]

4) **PGS** - PGS charged $2.30 million of other labor expense (and a small amount of miscellaneous property sublease expense) to TECO.

5) **NMG** - NMG charged $.20 million of information technology expenses (and a small amount of labor) to TECO.

6) **Other Affiliates** - A combination of other affiliates charged $.10 million of labor to TECO.

7) **TECO Partners, Inc.** – TECO Partners, Inc. charged an immaterial amount of labor to TECO.

Q. PLEASE DESCRIBE HOW THE CAMS ALLOCATE OR DIRECT ASSIGN EXPENSES AMONG AFFILIATES.

A. Both the January 1, 2020, TECO Energy, Inc., CAM (effective through 2023) and January 1, 2024, TECO Holdings, inc., CAM describe the same process for either the allocation or direct assignment of expenses to TECO and affiliates.[17] Tampa

[15] I am not reviewing TECO's $17.60 Million share of the total direct assigned expenses of $23.40 Million because these types of direct expenses will be subject to the review by OPC witness Mr. Kollen in this rate case.

[16] These amounts are from TECO's response to OPC's Sixth Set of Interrogatories and PODs, Interrogatory No. 103 and POD No. 81, per Excel spreadsheet "(BS 15597) Shared Services Schedule 2023.xlsx."

[17] Both the January 1, 2020, TECO Energy, Inc. CAM and the January 1, 2024, TECO Holdings, inc. CAM were provided at TECO's response to OPC's First Set of Interrogatories and POD, Interrogatory No. 58 and POD No. 34.

Electric/TECO assigns costs in the following order: 1) direct costs charged to a specific affiliate; 2) indirect costs for Shared Services allocated/assessed to more than one affiliate using statistical cost drivers or allocation factors (i.e., number of employees/headcount, number of claims, etc.); and 3) the remaining indirect costs for Corporate Services are allocated to more than one affiliate using the MMM.

TECO sometimes interchangeably uses the terminology of "allocation" or "assessment" when addressing costs that are not direct assigned, but are instead allocated/assessed using either the MMM or some other statistical cost driver or allocation factor. However, my testimony will most often use the terminology of "allocated" to describe costs charged to TECO from other affiliates (or charged by Tampa Electric/TECO to other affiliates) that are subject to some type of allocation factor or statistical cost driver and which are not direct assigned.

I do not disagree with the CAM-described method and approach regarding the following: 1) allocation of indirect expenses to affiliates that use these common services or Corporate/TECO overheads; and 2) assigning direct expenses to specific affiliates which caused those costs to be incurred (although I believe that all expenses should be direct assigned whenever possible). However, I do not agree with all specific allocation factor inputs used in the MMM or with other statistical inputs/drivers for other allocation factors. Later in my testimony, I will address my recommended adjustments to the MMM and statistical inputs/drivers.

34. This Q and A includes information from the January 1, 2020 TECO Energy, Inc. CAM, page 3 and the January 1, 2024, TECO Holdings, inc. CAM, pp. 3-4.

V. TECO CENTRALIZED SERVICES AND FERC WAIVER

Q. PLEASE EXPLAIN THE SHIFT OF CENTRALIZED SERVICE PROVIDER FROM TECO SERVICES, INC. TO TECO, AND EXPLAIN HOW THIS IS TIED TO TECO'S REQUESTED WAIVER OF CERTAIN FERC AFFILIATE TRANSACTION RULES.

A. The following explanations for changes in the corporate structure and the provision of centralized services are from: a) the January 1, 2020, TECO Energy, Inc. CAM (describing the structure from Emera's acquisition of TECO on July 1, 2016, through December 31, 2023); and b) the current January 1, 2024, TECO Holdings, inc., CAM describing the current structure effective January 1, 2024.[18] The following describes the transition from TECO Services, Inc. to TECO as a surrogate centralized service company, providing shared and corporate services for certain U.S. regulated public utilities and some other unregulated affiliates.[19] This transition to TECO as a centralized service company did not impact allocations from Emera and Emera Energy Services, Inc. to TECO and other foreign and U.S. regulated and unregulated affiliates.

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[18] Both the January 1, 2020, TECO Energy, Inc. CAM and the January 1, 2024, TECO Holdings, Inc. CAM were provided with TECO's response to OPC's First Set of Interrogatories and POD, Interrogatory No. 58 and POD No. 34. The specific CAMs were included within the September 14, 2023, NMG Direct Testimony and Exhibits of Kevin I. Farr in Case No. 23-00255-UT before the New Mexico Public Regulation Commission, *In the Matter of the Application* of New Mexico Gas Company, Inc. for Approval of Revisions to its Rates, Rules, and Charges Pursuant to Advice Notice No. 96. The January 1, 2022, TECO Energy, Inc. CAM is located at BS 16774 – 16797 and the January 1, 2024, TECO Holdings, Inc. CAM is located at BS 16798 – 16819. This Q and A includes information from the January 1, 2020 TECO Energy, Inc. CAM, pp. 1-2 and the January 1, 2024, TECO Holdings, Inc. CAM, pp. 1-2.

[19] Per the TECO Holdings, inc. CAM effective January 1, 2024, Exhibit B shows that TECO currently provides shared services to the regulated utilities and other unregulated utilities of: TECO, PGS, NMG, TECO Energy Services, Inc., TECO Energy, TECO Pipeline Holding Company, LLC, TECO Partners, Inc., TECO Gemstone, Inc., TECO Properties Corp., TECO Energy Source, Inc., TECO Finance, Inc., SeaCoast, and TECO Holdings, inc.

Emera acquired TECO Energy, Inc.[20] in July 1, 2016, and since that time Emera has allocated Corporate Support Services expense and labor expense to TECO (and other affiliates) via an intermediary centralized service company called TECO Services, Inc. along with other expenses that are direct assigned from Emera to TECO. In addition, Emera Energy Services, Inc.[21] provides certain services to TECO via an Asset Management Agreement.[22]

Since January 2014 (prior to the Emera acquisition of TECO), TECO Energy, Inc. had been providing service functions to its operating companies and other affiliates via a centralized service company TECO Services, Inc.[23] (owned by TECO Holdings, inc.).[24]

On July 13, 2019,[25] TECO filed a waiver request with the FERC stating that effective January 1, 2020, TECO Services, Inc. would cease operations as a centralized service company allocating and assigning expenses to TECO Energy, Inc. affiliates[26] and TECO would begin providing these same centralized services to the same affiliates. Although TECO does not formally refer to itself as a centralized service company, I believe that TECO is essentially a "surrogate" (or *de facto*) centralized service

[20] At the time of Emera's acquisition, TECO Energy, Inc. consisted of the operating companies of TECO, PGS, NMG, and TECO Pipeline Holding Company, LLC.
[21] Emera Energy Services, Inc. is a direct affiliate of Emera.
[22] My testimony will address concerns regarding transactions between TECO and Emera Energy Services, Inc., including TECO's failure to provide supporting documentation and failure to show related expenses charged to TECO.
[23] In addition, TECO Services, Inc. has been providing services to the affiliates of TECO Holdings, Inc., TECO, PGS, NMG, TECO Pipeline Holding Company, LLC, TECO Partners, Inc, TECO Gemstone, Inc., TECO Properties Corp., TECO Energy Source, Inc., and TECO Finance, Inc.
[24] These centralized service functions include executive oversight, finance, corporate planning, corporate development, legal, human resources, procurement, and government affairs.
[25] TECO's waiver request was supplemented on September 18, 2019.
[26] TECO Services, Inc. ceased providing centralized service functions on December 31, 2019, although periodically, TECO Services, Inc. could provide services to other Emera or TECO Energy, Inc. affiliates and direct charge those services to affiliates.

company in all material respects because it performs all of the same services and allocates all of the same types of expenses to the same affiliates as TECO Services, Inc. (the prior centralized service company). My testimony will subsequently address additional concerns regarding this matter.

Since TECO began providing centralized service functions to affiliates on January 1, 2020, TECO desired a corresponding FERC waiver of two affiliate transaction sections, FERC 18 C.F.R. § 35.44(b)(1) and § 35.39(e)(1) by this same date. The FERC granted TECO's waiver request on October 30, 2019, for implementation at January 1, 2020.[27] FERC approved this waiver without a specific CAM in place for Emera.

The two FERC affiliate transaction sections requested for waiver are summarized below:

1) **18 C.F.R. § 35.44(b)(1)**:

(b) Non-power goods or services.

(1) Unless otherwise permitted by Commission rule or order, and except as permitted by paragraph (b)(4) of this section, sales of any non-power goods or services by a franchised public utility that has captive customers or that owns or provides transmission service over jurisdictional transmission facilities, including sales made to or through its affiliated exempt wholesale generator or qualifying facilities, to a market-regulated power sales affiliate or non-utility affiliate must be at the higher of cost or market price.

2) **18 C.F.R. § 35.39(e)(1)**:

(e) Non-power goods or services.

~~[27] FERC waiver, 169 FERC ¶61,081, United States of America Federal Energy Regulatory Commission, Docket No. ER19-2439-000, Order on Request for Waiver of Affiliate Pricing Rules, issued October 30, 2019 ("FCC Waiver").~~

[27] FERC waiver, 169 FERC ¶61,081, United States of America Federal Energy Regulatory Commission, Docket No. ER19-2439-000, Order on Request for Waiver of Affiliate Pricing Rules, issued October 30, 2019, pp. 2-3. ("FERC Waiver").

> **(1)** Unless otherwise permitted by Commission rule or order, sales of any non-power goods or services by a franchised public utility with captive customers, to a market-regulated power sales affiliate must be at the higher of cost or market price.

Essentially, FERC 18 C.F.R. § 35.44(b)(1) and § 35.39(e)(1) affiliate transaction sections state that a regulated public utility's (such as TECO) sale of non-power goods and services to market-regulated power sales affiliates (and unregulated non-utility affiliates) must be at the "higher of cost or market price." TECO sought to waive these two FERC affiliate transaction sections so that TECO would be able to provide non-power goods and services to market-regulated power sales affiliates (and/or non-utility affiliates) at "cost," instead of at the "higher of cost or market."

I am not concerned that TECO received a FERC waiver for section 35.39(e)(1) or for most of section 35.44(b)(1) - so that TECO can sell non-power goods or services to a "market-regulated power sales affiliate" at cost. However, I do have some concern that TECO received a complete FERC waiver to 35.44(b)(1), and specifically the language near the end which states that any sales of non-power goods or services by regulated public utility to a "non-utility affiliate" must be at the higher of cost or market price. This means that TECO can sell non-power goods and services to any <u>unregulated non-utility</u> affiliate at cost, instead of the higher of cost or market price. This means that TECO is foregoing the receipt of greater revenues from an unregulated, non-utility affiliate when it provides goods and services at a cost that is below market price, because TECO should be receiving greater revenues reflected at the market price (the higher of cost or market). Also, and most importantly, this means that TECO could be providing a subsidy to a non-utility affiliate.

VI. AFFILIATE TRANSACTION POLICY AND RULES

Q. PRIOR TO ADDRESSING THE STATE AFFILIATE TRANSACTION RULES, CAN YOU EXPLAIN THE IMPORTANCE OF THE FERC AFFILIATE TRANSACTION RULES (AND AFFILIATE TRANSACTION RULES IN GENERAL)?

A. In its simplest form, the primary purpose of the FERC's affiliate transaction rules in 18 C.F.R. § 35.39 (Affiliate restrictions), § 35.43 (Generally), and § 35.44 (Protections against affiliate cross-subsidization) are to protect against a regulated utility unfairly subsidizing its unregulated affiliates.[28] The rules conservatively require that: 1) all sales of goods and services from an unregulated affiliate to a regulated utility are provided at the lower of cost or market price; and 2) all sales of goods and services from a regulated utility to an unregulated affiliate are provided at the higher of cost or market price.

Affiliate transaction rules generally require an unregulated affiliate to sell goods and services to a regulated utility affiliate at the lower of cost or market price, to conservatively ensure that the regulated utility affiliate is not paying excessive prices that will result in subsidizing the unregulated affiliate to the detriment of the regulated utility affiliate (or to the detriment of market competition). Similarly, affiliate transaction rules generally require a regulated utility affiliate to sell goods and services to an unregulated affiliate at the higher of cost or market price, to similarly ensure that the regulated utility affiliate is receiving fair value that will not result in it subsidizing

[28] These unregulated affiliates include the unregulated holding company, unregulated service company, and other unregulated affiliates providing non-tariffed services and products.

the unregulated affiliate to the detriment of the regulated utility affiliate (or to the detriment of market competition).

In a worst case scenario, if the unregulated affiliate charges excessive prices for goods and services to the regulated utility, then the regulated utility recovers these excessive costs in rate case proceeding via excessive rates passed along to customers. In another worst case scenario, if the unregulated affiliate charges excessive prices for goods and services to the regulated utility, the regulated affiliate could use these excess monopoly profits to subsidize its other competitive services that it offers in the market.

Q. PLEASE EXPLAIN PROTECTIVE MEASURES IN THE FLORIDA AFFILIATE TRANSACTION RULES.

A. Florida's rule 25-6.1351, Florida Administrative Code ("F.A.C."), Cost Allocation and Affiliate Transactions rules provide minimal protective measures for consumers, even without any consideration of the FERC's waiver. The minimal affiliate transaction protective measures in place at rule 25-6.1351(3)(b)(c)(d), F.A.C, only address the least important and smallest amount of affiliate transactions between TECO and its non-utility affiliates (TECO's FERC waiver application already admitted that these transactions were minimal), because the Florida rules do not govern the largest affiliate transactions between TECO and Emera, its regulated utility affiliates, and its centralized service provider TECO.

The primary Florida affiliate transaction rules are set forth below (along with my comments beneath each rule section), with all rules falling under subsection **(3) Non-Tariffed Affiliate Transactions**, per rule 25-6.1351(3), F.A.C. I will address my understating of the applicability of Florida's affiliate transaction rules based on my expertise on affiliate transactions.

1) **<u>Florida Rule 25-6.1351(3)(a</u>)**, **F.A.C**, states:

> *The purpose of subsection (3) is to establish requirements for non-tariffed affiliate transactions impacting regulated activities. This subsection does **not** apply to the allocation of costs for services between a utility and its parent company or between a utility and its regulated utility affiliates or to services received by a utility from an affiliate that exists solely to provide services to members of the utility's corporate family. All affiliate transactions, however, are subject to regulatory review and approval. (Emphasis added)*

The above rule 25-6.1351(3)(a), F.A.C, specifically exempts and disallows affiliate transaction protective measures for the following types of affiliate transactions (which happen to be the largest affiliate transactions impacting TECO and Emera).

First, Florida rule 25-6.1351(3)(a), F.A.C, specifically exempts and does not provide any protective measures for affiliate transactions between a utility and its parent company. This specifically exempts per rule 25-6.1351(3)(a), F.A.C, the second largest amount of expenses allocated from Emera to TECO (over $4.1 million allocated in 2023).

Second, Florida rule 25-6.1351(3)(a), F.A.C, specifically exempts and does not provide any protective measures for transactions between a utility and its regulated utility affiliates. This is the single largest amount of expenses allocated from Tampa Electric/TECO (the regulated utility and centralized service provider) to its regulated utility affiliates of TECO, PGS, and NMG ($72.8 million allocated in 2023, mostly to TECO, PGS, and NMG)

Finally, Florida rule 25-6.1351(3)(a), F.A.C, specifically exempts and does not provide any protective measures for transactions related to services received by a utility

C23-2209

from an affiliate that exists solely to provide services to members of the utility's corporate family, such as a centralized service company. This type of transaction covers the same transactions mentioned in the prior rule, because it is also applicable to the TECO centralized service provider that exists only to provide shared services to the corporate family of affiliates of TECO, PGS, NMG, and other affiliates ($72.8 million allocated in 2023). Technically, the "centralized service provider" does not provide utility services or services to any non-affiliate, so it falls under this exemption.

2) **<u>Florida Rule 25-6.1351(3)(b), F.A.C</u>**, states:

> *A utility must charge an [unregulated][29] affiliate the higher of fully allocated costs or market price for all non-tariffed services and products purchased by the [unregulated]affiliate from the utility. Except, a utility may charge an [unregulated] affiliate less than fully allocated costs or market price if the charge is above incremental cost.*

In my opinion, the last provision of Section 25-6.1351(3)(b), F.A.C., that requires the price to be a minimal "incremental cost" amount negates any meaningful protection measure because a utility could not earn a reasonable return on equity (or rate of return) if it charged prices at incremental cost for all of its services.

3) **<u>Florida Rule 25-6.1351(3)(c), F.A.C</u>**, provides that:

> *When a utility purchases services and products from an [unregulated] affiliate and applies the cost to regulated operations, the utility shall apportion to the regulated operations the lesser of fully allocated costs or market price. Except, a utility may apportion to regulated operations more than fully allocated costs if the charge is less than or equal to the market price.*

As I discussed above, due to the Section (a) Florida rule exceptions, this affiliate transaction rule does not apply to transactions between a regulated utility and its: a)

[29] I have included the term "unregulated" affiliate, because this is the only remaining type of affiliate subject to affiliate transaction rules given the previous Florida rule exemptions, and I have repeated this ~~in~~ term in rule 25-6.1~~352~~(3)(c) and 25-6.1~~352~~(3)(d), F.A.C.

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parent; b) another regulated utility affiliate; and c) a service company. Thus, this rule provides minimal protection because most of TECO's transactions with affiliates are exempt from this affiliate transaction rule.

4) **<u>Florida rule 25-6.1351(3)(d), F.A.C</u>**, states:

> *When an asset used in regulated operations is transferred from a utility to a nonregulated affiliate, the utility must charge the [unregulated] affiliate the greater of market price or net book value. Except, a utility may charge the [unregulated] affiliate either the market price or net book value if the utility maintains documentation to support and justify that such a transaction benefits regulated operations.*

Given the prior Section (a) Florida rule exceptions, in my opinion, this affiliate transaction rule would not apply to transactions between a regulated utility and its: a) parent; b) another regulated utility affiliate; and c) a service company. Thus, this rule provides minimal protection because most of TECO's transactions with affiliates are exempt from this affiliate transaction rule.

The bottom line is that existing Florida affiliate transaction rules provide very minimal protective measures to consumers (and potential competitors). I would recommend that the Commission explore adding more protective measures for customers similar to those provided in FERC's Rules 35.44(b)(1) and 35.39(e)(1).

<u>VII. CONCERNS WITH TECO AS A CENTRALIZED SERVICE COMPANY</u>

Q. DO YOU HAVE CONCERNS WITH TECO'S ROLE AS A REGULATED UTILITY PROVIDING CENTRALIZED SERVICES BASED ON YOUR FAMILIARITY WITH TRADITIONAL NON-UTILITY AFFILIATES PROVIDING CENTRALIZED SERVICES?

A. Yes. As I previously indicated, TECO essentially replaced TECO Services, Inc. as the centralized service company on January 1, 2020, because TECO now provides the same centralized services to the same group of affiliates as previously provided by TECO Services, Inc. Thus, TECO is a centralized service company in all material respects (when considering substance over form), or a "surrogate" centralized service company at the minimum.

In rate case proceedings where I have reviewed affiliate transaction issues, it has been my experience that centralized service companies are non-utility affiliates, and the service company has only one primary responsibility -- to provide corporate support services to other regulated and unregulated affiliates, while the service company is primarily responsible for the detailed affiliate transaction supporting documentation. I believe it is very unusual for a regulated utility, such as TECO, to serve in the role as the primary centralized service company.

Some of my primary concerns with TECO, the regulated utility, providing services to other regulated and unregulated affiliates as a "surrogate" centralized service company are listed below in no particular order of priority.

First, TECO's FERC waiver request stated that it could provide centralized services more efficiently (and reduced overhead expenses) than prior centralized service provider TECO Services, Inc., and simplify the corporate structure. TECO has failed to provide any meaningful documentation to meet its burden to demonstrate that its assumption of centralized service company responsibilities has resulted in increased efficiency and a reduction in overhead expenses. Information provided by TECO

C23-2212

shows that allocated expenses have increased after TECO became the centralized service provider.

Second, there is the risk that TECO (serving dual roles as both a regulated utility and centralized service provider) does not have a strong incentive to reduce centralized service expenses and be efficient. When PGS took back certain Procurement shared services in-house, instead of this leading to decreased expenses for these Procurement services due to a reduction in demand, TECO significantly increased these Procurement expenses in subsequent years and essentially made TECO the guarantor for recovery of these expenses. This unfairly penalized TECO for remaining in the centralized shared services cost pool, despite there not being a cost-causation basis to support significant increases in costs to TECO.

Third, TECO's primary role as a regulated utility that also provides centralized services can increase the potential exposure to cross-subsidization, compromise objectivity and independence, and raise concerns regarding the oversight of affiliate transactions. This is a particular concern when certain safeguards do not exist. For example, there has never been an internal audit of TECO's affiliate transactions by either the internal audit division of Emera or TECO.

Fourth, when TECO's complicated accounting for affiliate transactions is comingled with its day-to-day accounting transactions as a regulated utility, it becomes more difficult to identify the impact of affiliate transactions on TECO's books. Further, there is not a reasonable audit trail for these expenses.

Q. HAS TECO PROVIDED DOCUMENTATION TO SHOW ITS SHARED SERVICE EXPENSES HAVE DECREASED AFTER IT BECAME THE CENTRALIZED SERVICE PROVIDER?

A. No, because TECO shared service expenses have actually increased since it replaced TECO Services, Inc. as the *de facto* centralized service provider.

TECO's waiver application with the FERC states the shared services it will now provide instead of TECO Services, Inc. are intended "… to simplify their collective corporate structure, and thereby reduce overhead and capture efficiency benefits associated with housing the provision of centralized shared services within the TECO family under 'one roof.'"[30] TECO has not provided any documentation to support its stated benefits related to becoming the centralized service company, thus TECO has failed to meet a reasonable burden of proof in this regard.

TECO has not provided any documentation to show that shared service overhead expenses have decreased or that any efficiency benefits have been captured. In fact, both total allocable shared services expenses (to be allocated to TECO and other affiliates), and shared services allocated specifically to TECO, have increased based on actual shared service expenses for calendar years 2020 through 2023, and the 2025 budget/forecast used for establishing the revenue requirement and requested rate increase in this rate case. TECO assumed the role as centralized service provider of shared service expenses effective January 1, 2020, but shared service expense for 2019 under the prior centralized service provider, TECO Services, Inc., is not available – which only means a first year comparison is available. OPC originally requested the

[30] TECO July 23, 2019, FERC waiver application, p. 5, and the FERC Order issued October 30, 2019, granting the waiver, p. 2.

2019 shared service expense, but TECO did not provide this information because it stated such information was flawed or was not available on a comparable basis for comparison to subsequent years.

However, shared service expense have gradually increased with TECO as the centralized service provided from 2020 through the 2025 budget/forecast amounts.

Total shared service expense (subject to allocation TECO and all affiliates) decreased from $68.70 million in 2020 to $68.20 million in 2021, and then subsequently increased every year from $72.30 million in 2022, to $72.80 million in 2023, and with one of the largest annual increases to $74.10 million for the 2025 budget/forecast.[31] After a minor reduction in Total shared services expenses of $.50 million from 2020 to 2021, TECO's second year as the centralized service provider produced an unusual significant and alarming increase of $4.10 million from 2021 to 2022 which removed any question about claimed benefits as the centralized service provider. After the minor decrease in shared service expenses from 2020 to 2021, the subsequent four-year average, annual increase in expense was $1.48 million per year from 2021 through 2025/budget. This average annual "increase" is conservatively low and would have been greater except TECO shifted some services from being "allocated" to now being "direct assigned," such as Corporate Communications.

[31] The Total shared service expenses for 2020, 2021, 2022, and 2023 are from TECO's response to OPC Fifth Set of Interrogatories and PODs, Interrogatory No. 95 and POD No. 71, Excel spreadsheets tiled, "(BS 19213) Shared Services Schedule 2020.xlsx", and similar spreadsheets at BS 19214 (Shared Services for 2021), BS 19215 (Shared Services for 2022), BS 19216 (Shared Services for 2023). Total shared service expenses for the 2025 Budget are from TECO's response to OPC Second Set of Interrogatories and PODs, Interrogatory No. 63 and POD No. 39, Excel spreadsheet titled "(BS 17337) TEC SS Budget Schedule 2025.xlsx." Also, TECO's response to OPC Sixth Set of Interrogatories and PODs, Interrogatory No. 103 and POD No. 81, provided file POD_No._81 which included a spreadsheet titled, "(BS 19597) Shared Services Schedule 2023.xlsx.", which is the same Shared Services Schedule for 2023 that was provided in response to POD No. 71 as BS 19216 cited above in a request for Management Reports regarding affiliate transactions.

TECO's allocated portion of the Total shared service expense decreased from $48.20 million in 2020, to $47.40 million in 2021. Thereafter, these expenses subsequently increased every year from $49.80 million in 2022, to $50.60 million in 2023, and with the largest increase to $51.80 million for the 2025 budget/forecast.[32] After a reduction in TECO's shared services expenses of $.80 million from 2020 to 2021, in TECO's second year as the centralized service provider, the same significant and alarming increase of $2.40 million from 2021 to 2022 happened. Once again removing any question about claimed benefits from TECO serving as the centralized service provider after only serving a short time in this role.

The available information shows that shared service expenses have increased almost annually under TECO's guidance as the centralized service provider, and TECO has not provided any documentation to show evidence of increased efficiency or a reduction in these shared service expenses.

TECO's FERC waiver also claimed that its role as the centralized service provider would simplify the corporate structure. This is not true. TECO Services, Inc., the prior centralized service provider, is still in operation and even periodically provides services to other Emera or TECO affiliates and direct charges these services. Thus, there is no evidence that TECO's role as the centralized service provider has resulted in any corporate structure simplification or related cost savings.

There is no evidence to show that TECO has operated more efficiently than prior centralized service provider TECO Services, Inc., which was a stand-alone non-utility affiliate whose only responsibility was to provide centralized services. Further,

[32] *Ibid.*

the role of the centralized services provider added unnecessary responsibility to the role of being a regulated public utility and carrying out important obligations in that role.

Q. CAN YOU PROVIDE AN EXAMPLE WHERE TECO'S ACTIONS AS A CENTRALIZED SERVICE PROVIDER DO NOT APPEAR TO PROMOTE REDUCED SHARED SERVICE EXPENSES?

A. Yes, I can. There is a reasonable risk that TECO does not have a strong incentive to reduce centralized shared service expenses in its dual role as regulated utility and centralized service provider. This is because TECO can directly and specifically influence and impact the amount of centralized shared service expense that Tampa Electric/TECO allocates to TECO and other affiliates, and this allows TECO to impact the amount of shared services expense that it seeks to recover in a rate case proceeding. In a rate case proceeding, TECO may not have a strong incentive to reflect reduced centralized service expenses either via its actual shared service expenses incurred or via its projected/forecasted 2025 shared service expenses used for the revenue requirement calculation in this proceeding. As I discuss below, I provide an example where TECO's 2023 shared service expenses are increasing and may not reflect market or competitive price levels for certain shared services.

For example, OPC asked about the reasons for the changes in the percent and amount of Procurement shared service expenses allocated to TECO from 2020 through the 2025 budget/forecasted period. TECO's response stated that the percent of Procurement expenses allocated to TECO increased from 2022 to 2023 because the percent of expenses allocated to PGS also correspondingly decreased for this same period due to PGS establishing its own supply chain management group in 2023.[33] In other words, Procurement expenses previously incurred by PGS in 2022 are now shifted mostly to TECO, as the regulated entity, in 2023 due to PGS taking back this function in-house in 2023 and not paying TECO, as the centralized service provider, to furnish this as a shared service in 2023 and going forward. I will address my concerns after the table below.

Table 1
Increased TECO Procurement Expense Due to PGS Take-Back

	A	B	C	D
		Procurement Shared Service Expense		
	(In Millions)	Subject to "PO Spend" Allocator		
Ln	Description	2022	2023	2025 Budget
1	Total Subject to Allocation	$4.60	$5.40	$6.30
2	Expense Allocated to TECO	$3.60	$4.80	$6.00
3	Percent Allocated to TECO	79.41%	89.40%	94.06%
4	Expense Allocated to PGS	$0.80	$0.50	$0.30
5	Percent Allocated to PGS	18.42%	9.68%	5.0%
6	Note - Remaining Procurement Shared Services Expenses Are			
7	Allocated to other Affiliates			

The above table shows the total amount of Procurement shared service expense[34] subject to allocation to TECO, PGS, and all other affiliates by TECO (line 1, columns B, C, and D); lines 2 and 4 show the amount of the total Procurement expense that is allocated to TECO and PGS, respectively; and lines 3 and 5 show the

[33] TECO's response to OPC's Tenth Set of Interrogatories and Eleventh Set of PODs, Interrogatory No. 177(e) and POD No. 136.
[34] This is the TECO total Procurement shared service expense that is subject to being allocated to affiliates using the "Purchase Order Spend" allocation factor. There are other Procurement shared service expenses that are allocated to affiliates using a "Headcount" allocation factor, but these expenses are not as significant.

percent of Procurement expense allocated to TECO and PGS, respectively.[35] The table shows actual amounts for calendar years 2022 and 2023, and the 2025 budget amount used for determining the revenue requirement in this rate case.

The above table shows for 2022 (prior to PGS establishing its own supply chain management group), of the total Procurement shared service expense of $4.60 million, TECO allocated $3.60 million (79.41%) to TECO and allocated $.80 million to PGS (18.42%), and any remaining amounts are allocated to other affiliates. In 2023, when PGS began providing its own supply chain services in-house (and did not purchase these services from TECO shared services), the total amount of Procurement expense subject to allocation increased by $.90 million (from $4.60 million in 2022 to $5.40 million in 2023), and the percent allocated to TECO increased by about 10% (from 79% in 2022 to 89% in 2023), and correspondingly the percent allocated to PGS decreased by about 8% (from 18% to 10%) – which is roughly the same percentage increase incurred by TECO. This shift in Procurement expense to TECO was also impacted by the increased purchase order ~~headcount allocation~~ factor for TECO.

Finally, for the 2025 Budget, the total amount of Procurement expense subject to allocation has increased by $.90 million (from $5.40 million to $6.30 million), with the amount allocated to TECO increasing by $1.20 million (from $4.80 million in 2023 to $6.0 million for the 2025 Budget), with the corresponding percent allocated to TECO increasing by 5% (from 89% in 2023 to 94% for the 2025 Budget), and the Procurement

[35] The Procurement expense amounts in the above table are per the shared service expenses for 2020, 2021, 2022, and 2023 from TECO's response to OPC's Fifth Set of Interrogatories and PODs, Interrogatory No. 95 and POD No. 71, Excel spreadsheets tiled, "(BS 19213) Shared Services Schedule 2020.xlsx", and similar spreadsheets at BS 19214 (Shared Services for 2021), BS 19215 (Shared Services for 2022), BS 19216 (Shared Services for 2023). Total shared service expenses for the 2025 Budget are from TECO's response to OPC Second Set of Interrogatories and PODs, Interrogatory No. 63 and POD No. 39, Excel spreadsheet titled "(BS 17337) TEC SS Budget Schedule 2025.xlsx."

expense allocated to PGS decreased $.20 million (from $.50 million in 2023 to $.30 million for the 2025 Budget) and the percent allocated declining by 5% (from 10% in 2023 to 5% for the 2025 Budget).

My primary concern is that despite PGS taking back significant Procurement functions in-house in 2023 and reducing its shared service expense,[36] TECO, the centralized services provider, continued to significantly increase the total Procurement expense while shifting an increasing and significant amount of the residual Procurement expense to TECO, the regulated entity, (after the loss of PGS services). Thus, TECO centralized services increased total Procurement expense by $1.7 million (37%) from $4.60 million in 2022 to $6.30 million per the 2025 Budget. Most devastating, TECO, as the centralized services provider, residually shifted almost all of these increased Procurement costs to TECO, as the regulated entity, from 2023 to the 2025 Budget, increasing TECO's Procurement expense by a significant and alarming amount of $2.5 million and 67% from $3.60 million in 2020 to $6.00 million per the 2025 Budget. This caused the percent of Procurement expenses allocated to TECO to increase from 79% in 2022 to 94% per the 2025 Budget, meaning that TECO, as the regulated entity, would pay for almost all of the TECO, the ~~centralize~~ centralized service provider's, Procurement budget by itself.

I believe that PGS taking back its own supply chain management group in-house is an indication that PGS could provide these services to itself on a less expensive and more efficient basis than TECO could provide these centralized services to PGS. The PGS take-back of these services in-house should have prompted concern with

[36] Instead of PGS paying TECO for these shared services in 2023 and going forward.

TECO, and caused them to evaluate and reduce the cost of their Procurement services so these costs are more representative of a competitive market level for these services. Thus, the PGS take-back of the Procurement service could be an indication that these services are not priced as efficiently and effectively as they would be in a competitive market, and may even be excessive and unreasonable.

In a competitive market, one reasonable response is that company would react with reductions in the price[37] of its services to avoid losing potential clients to competitors with market-competitive prices. In essence, there is less demand for the centralized Procurement service with the loss of PGS, and this should have prompted a reduction in cost for these services.

However, because of the dual role of TECO as regulated utility and centralized service provider, I believe there was less incentive to reduce the costs of the Procurement services because these costs can be recouped from captive customers in this monopoly environment. In addition, it makes common sense that when less services are provided (such as the reduction in Procurement services provided to PGS), then a company should reasonably look at reducing the corresponding costs for that service. When I refer to the costs and cost reductions for Procurement centralized services, I believe that the number of employees and labor costs (along with the related overhead costs) should be reduced as a reasonable response to less demand for these services (that likely stem from excessive or unreasonable costs).

Also, because PGS has reduced its purchase of Procurement services, TECO has become the virtual guarantor for recovery of all residual Procurement costs at

[37] Or the competitive market could also react by offering more services and better quality for the price of the service.

elevated levels, with TECO now responsible for paying for 94% of the total Procurement centralized services under TECO's 2025 Budget proposal. It is not reasonable for TECO to be the guarantor for recovery of these Procurement costs at any expense level. Most importantly, if another affiliate acts reasonably to take services back in-house and rely less upon TECO's centralized services, then TECO, the regulated entity, should not be irreparably harmed by having to guarantee these lost centralized service revenues to TECO, the centralized service provider. This is not a normal competitive-market and real world reaction to this type of situation. Additionally, shifting Procurement costs from one affiliate to another to guarantee full recovery of Procurement costs is not supported by any reasonable cost-causation principles. TECO, the regulated utility, did not cause the centralized service provider TECO to lose Procurement services via the PGS take-back of these services in-house, and there is no cost-causation justification for requiring TECO, the regulated entity, to pay for the residual and significant increasing cost of Procurement service.

I have addressed my concerns with this matter, and similar issues, by proposing adjustments later in my testimony. In those adjustments, I am mitigating the negative impact of excessive or unreasonable residual cost allocation to TECO, which is also a way to address the significant unsupported increase in Procurement costs in 2023 (and projected through the 2025 Budget costs). TECO has not met a reasonable burden of proof because it has not provided adequate supporting documentation to justify the significant increase in costs of Procurement services, and the related unfair practice of residually allocating all Procurement costs to TECO, as the regulated entity, when another affiliate takes services back in-house and relies less upon TECO's centralized services.

Finally, my bottom line concern regarding the above testimony goes to TECO's dual role as both a regulated utility and centralized service provider. If a stand-alone unregulated affiliate was providing centralized services there would be more incentive to act responsibly and reduce centralized service costs under the conditions that I described. In contrast, a regulated utility like TECO has less incentive to reduce centralized service costs and has more incentive to make the regulated utility the guarantor for recovery of all residual centralized service cots, because these costs can be recouped from customers in a rate case proceeding.

Q. DOES TECO'S PRIMARY ROLE AS A REGULATED UTILITY INCREASE THE EXPOSURE FOR CROSS-SUBSIDY AND COMPROMISE INTERNAL CONTROLS AND OBJECTIVITY AS A CENTRALIZED SERVICE PROVIDER?

A. Yes. TECO's responsibilities as both a regulated utility and centralized service provider raises potential concerns of cross-subsidy and the compromise of internal control safeguards and objectivity. I previously explained there can be an incentive for other affiliates to charge above-market costs to the regulated utility[38] and for the regulated utility to charge below-market costs to other affiliates.[39] If cross-subsidization occurs between the regulated utility and the other unregulated affiliates,

[38] Thus, FERC (and some state regulatory agencies) have rules or policy generally requires that affiliates charge services to the regulated utility at the lower of cost or market prices.
[39] Thus, FERC (and some state regulatory agencies) have rules or policy generally requires the regulated utility to charge services to other unregulated affiliates at the higher of cost or market prices.

this can result in: 1) excessive expenses on the regulated utility's books being passed through to customer rates in a rate case; or 2) other affiliates (that offer competitive services) gaining an unfair price advantage in the market by reducing its prices by the amount of any cross-subsidies and pricing its services at levels to gain market share (or to drive competitors out of business).

TECO, in its role as the centralized service provider for certain affiliates, could establish allocation methods or allocation factors that unreasonably overstate or understate the amount of transactions between Emera, TECO and other affiliates in order to game the system and promote cross-subsidization. Because TECO controls the books for recording these affiliate transactions, it could also manipulate accounting entries to promote cross-subsidization. Generally, most companies have reasonable separation of duties and internal controls in place to protect against improper accounting and other illicit transactions. This is another example of why there should be a reasonable separation of duties to discourage manipulation and malfeasance, and why the regulated utility should not also be the centralized service provider.

Technically, even if TECO was not the centralized service provider, TECO and the centralized service provider (and other affiliates) could still use collusion to carry out a cross-subsidy scheme. However, it is commonly understood from an accounting transaction perspective that while there is the potential for a cross-subsidy scheme, this does not prevent the implementation of reasonable safeguards and internal controls. In the rate case proceedings where I have reviewed affiliate transactions, I believe the exposure to potential cross-subsidization or even accounting malfeasance is mitigated

C23-2224

by the centralized service provider being a separate stand-alone unregulated affiliate that is not the same as the regulated public utility.

It is equally important for appearance purposes that a separate affiliate performs the centralized service provider function, in order to preserve and enhance objectivity and in order to more reasonably approximate third-party or arms-length transactions to mitigate any potential cross-subsidy and accounting malfeasance. It is always reasonable for there to be a proper separation of duties with the attendant safeguards and internal controls in place.

Finally, TECO has stated that no internal audits have been performed regarding the review of affiliate transactions for the calendar years 2019 to 2024,[40] which cover the last year of TECO Services, Inc. role as centralized service provider and the entire duration of TECO's role as centralized service provider. I believe this illustrates the lack of reasonable and responsible internal controls and safeguards regarding TECO's role as a centralized service provider. I would recommend that the Commission require Emera to perform an internal audit of TECO's affiliate transactions and report the results to the Commission or file this information in the next TECO or PGS rate case.

Q. DOES TECO'S COMINGLED ACCOUNTING TRANSACTIONS AS A DUAL PROVIDER OF CENTRALIZED SERVICES PROVIDER AND FOR DAY-TO-DAY REGULATED UTILITY OPERATIONS RESULT IN AFFILIATE TRANSACTIONS THAT CANNOT BE EASILY RECONCILED TO BOOK BALANCES?

[40] TECO's response to OPC's Second Set of PODs, POD No. 43.

A. Yes. TECO's books include comingled accounting transactions regarding affiliate transactions as a centralized service provider, along with day-to-day transactions regarding its regulated utility operations. This makes it more difficult to identify the impact of affiliate transactions on the books and to provide for a reliable audit trail when attempting to verify and validate the impact of affiliate transactions on expenses. Because TECO both purchases services from affiliates and sells services to affiliates (along with multiple ways of recording these transactions), this contributes to the difficulty in reviewing the impact of affiliate transactions on TECO's books.

For example, in most rate cases where I review affiliate transactions, the regulated utility records the allocated expenses for corporate support and overhead costs from the parent company or the centralized service company (and sometimes both) on its books. In most of these cases, the specific amount of these affiliate expenses can be easily identified on the regulated utility books in several Administrative and General expense accounts[41] (or subaccounts) and no detailed reconciliation of these expense amounts via confusing and voluminous Excel spreadsheets is required.

However, in this rate case proceeding, TECO does not have ending account balance on its books that readily show the affiliate expense for services provided by affiliates to TECO – and this expense amount cannot be tied directly to a specific Administrative and General expense account balance (or any specific expense account balance) on the TECO books. Likewise, TECO's books do not show an ending account balance reflecting TECO's affiliate contra expenses (or revenues) for services provided

[41] For most regulated utilities, the amount of affiliate expense paid by the regulated utility to an affiliate services is recorded in the accounts or subaccounts of the Administrative and Geneal expense account.

by TECO to affiliates – this contra expense or revenue amount cannot be tied directly to a specific Administrative and General contra expense (or any specific revenue account balance) on the TECO books. This is because TECO's books include a lot of comingled centralized service provider affiliate transactions (including expenses, expense offsets, and other entries to accounts receivable and other accounts) and day-to-day accounting transactions of the regulated utility operations.

For example, OPC asked TECO to reconcile its affiliate expenses to the Administrative and General expense for calendar year 2023 and the 2025 Budget at TECO Mr. Latta's MFR Schedule C-30, Schedule 1. TECO's responses[42] did not provide a reconciliation of the affiliate expenses to the Administrative and General expense account balance for 2023 or the 2025 Budget but instead just referred to a "net amount of affiliate charges contained in A&G accounts totaling ($13,163,452)." The negative amount of ($13,163,452) is not an ending account balance for any specific Administration and General expense balance, but is instead the result of netting certain detailed accounting transactions in the Administrative and General account.

Additionally, TECO referred to its response to other discovery responses,[43] specifically, the folder "POD_5-74" which included PDF document "(BS #19477-19511) POD_5_74_bates.pdf" that showed the FERC Form 1 summary of TECO affiliate transactions for 2023 and Excel spreadsheet "(BS #19476) 2240026-EI OPC

[42] TECO's response to OPC's Fifth Set of Interrogatories and PODs, Interrogatory No. 99 and POD No. 75.
[43] TECO's response to OPC's Fifth Set of Interrogatories and PODs, Interrogatory No. 98 and POD No. 74, and file "POD_5_74", including PDF document "(BS #19477-19511) POD_5_74_bates.pdf" and Excel spreadsheet "(BS #19476) 2240026-EI OPC Schedule 1 to 5th Set of ROGS_TEC Revised.xlsx." This Excel spreadsheet shows various net affiliate transaction amounts related to TECO "Purchase" of services from affiliates and TECO "Sale" of services to affiliates with for the periods 2020, 2021, 2022, 2023, 2024, 2024 Budget, and 2025 Budget. This similar Excel spreadsheet was also provided with Excel spreadsheet "OPC_Affiliate_Purchase by FERC" file, at BS 28786.

Schedule 1 to 5th Set of ROGS_TEC Revised.xlsx." This Excel spreadsheet was prepared by TECO to reconcile to the 2023 FERC Form 1 affiliate diversification data, and the spreadsheet shows the individual amount of affiliate transaction purchases and sells by affiliate that impact TECO for 2023, and the net amount of all these transactions equals the net negative balance of ($13,163,452) cited previously in the prior paragraph. Again, this Excel spreadsheet is a list of various net transactions with affiliates that impact various TECO accounts during 2023, but none of these net transactions for each affiliate agree or tie to an Administrative and General expense account balance for 2023.

Because TECO is unable to identify and provide specific ending account balances for affiliate transactions in its Administrative and General expense accounts, it appears that TECO has analyzed or queried its accounting books to identify the amount of affiliate transactions with various affiliates and provide these amounts in a spreadsheet – although none of these expense or other account balances for any particular affiliate will agree or tie to an ending account balance on TECO's books.

It is difficult to place a strong degree of reliance on the negative net transaction balance of ($13,163,452) or the individual net transactions of various affiliates when there are not any specific account balances on the books to which these amounts can be readily traced or agreed. Thus, there is not a clear or specific audit trail to reconcile these transactions to amounts on TECO's books or to ending account balances.

In addition, the dual role of regulated utility and centralized service provider unduly complicates, confuses, and makes it difficult to easily identify or reconcile the TECO purchase and sale of affiliate services. For example, OPC's Second Set of

Interrogatories, Interrogatory No. 61 and POD No. 37 asked for the allocation of all affiliates costs (and related allocations factors) to TECO (by function and type, and account number) from 2019 to 2024, and in response, TECO provided an Excel spreadsheet showing Emera's allocations to TECO and all other applicable foreign and U.S. regulated and unregulated affiliates from 2020 to 2023 (response dated April 22, 2024).[44]

OPC Interrogatory No. 61 included twelve sub-part questions and the related POD asked for all supporting documentation. TECO did not provide a written response to any of the twelve sub-part questions of Interrogatory No. 61 (except for multiple Objections), but instead its response to POD No. 37 only referred to attached "CONF_POD_2_37" with various voluminous Confidential spreadsheets, but no explanations were provided for amounts and other information in the voluminous spreadsheet.

Further, I was unable to reconcile the amounts allocated from Emera to TECO with various other documents provided by Emera. I raised this concern in informal conference calls between OPC and TECO, and no resolution or explanation was forthcoming. Thus, OPC issued its Tenth Set of Interrogatories and Eleventh Set of PODs, Interrogatory No. 179 and POD No. 138, as a follow-up because of the inability to reconcile Excel spreadsheet amounts in Confidential POD No. 61 to other TECO-provided documents.

[44] TECO's response to OPC's Second Set of Interrogatories and PODs, Interrogatory No. 61 and Confidential POD No 37, including file "CONF_POD_2-37" that included Confidential Excel spreadsheets "Emera Affiliate Allocations – Annual Summary 2023 041724 Highlighted.xlsx", "Emera Affiliate Allocations – Annual Summary 2022 041724 Highlighted.xlsx", "Emera Affiliate Allocations – Annual Summary 2021 041724 Highlighted.xlsx", and "(BS 16847) Emera Affiliate Allocations – Detailed Total 2021-2023_Highlighted.xlsx."

TECO's response, provided on May 23, 2024, almost a month after the initial Interrogatory and POD raising these issues, explained for the first time that the spreadsheets with Confidential POD No. 37 were expressed in Canadian currency, and this is why the amounts did not agree with other documents expressed in U.S. currency. It took substantial time and delay for TECO to make this determination of the conflicting currencies between various documents the Company provided. This is another example of the complexity and problems of a regulated utility trying to also fill the role as a centralized service provider.

I believe if TECO did not serve in the dual role of regulated utility and centralized service provider, the stand-alone books of both separate entities would be more simplified, easier to follow, and more likely to provide an audit trail to identify and reconcile affiliate transactions.

VIII. RECOMMENDATIONS FOR TECO AS A CENTRALIZED SERVICE PROVIDER

Q. BASED ON THE NUMEROUS PROBLEMS YOU HAVE IDENTIFIED WITH TECO'S DUAL ROLE AS A CENTRALIZED SERVICE PROVIDER AND REGULATED UTILITY, WHAT ARE YOUR BOTTOM LINE RECOMMENDATIONS?

A. It would likely be unacceptable for TECO to relinquish its centralized service provider responsibilities and to have another unregulated affiliate assume these responsibilities. In addition, it is not clear if the Florida Commission could require this divestiture – and the implications of this change in various jurisdictions for different affiliates could be problematic.

Also, even if TECO can provide additional documentation to show that its ascension to the role of centralized service provider did result in some cost savings and efficiencies, there should be proper consideration of any cost savings benefits weighted against the negative repercussions of a regulated utility serving as centralized service provider. These negative repercussions include less incentives to reduce centralized service costs allocated to affiliates, compromised safeguards and objectivity, increased exposure to cross-subsidy, absence of a strong audit trail to reconcile affiliate transactions, and the undue complexity of mixing conflicting objectives of a regulated utility and a centralized service provider.

However, in the absence of divesting TECO of centralized service provider responsibilities, I would recommend the following:

1) TECO should propose a timeline and plan for achieving all of the following recommendations with periodic updates to the Commission, OPC, and interested parties. The Plan should be filed and available to all parties, and in place within one year or before the next TECO or PGS rate case.

2) TECO should identify all prior and ongoing cost savings associated with becoming the centralized service provider, and TECO should identify these cost savings by year and account number (and any specific cost savings by affiliate) and provide all other supporting documentation and calculations. TECO should

propose a plan for flowing these cost savings back to customers in this rate case and future rate cases, or explain why this is not appropriate.

3) TECO should provide supporting documentation to explain and calculate the impact of all instances when an affiliate takes back certain centralized shared services in-house (and reduces or eliminates the reliance on the centralized shared services). TECO should provide alternative suggestions regarding how the residual costs of the related centralized shared service can be equitably treated among remaining affiliates, and explain why it would not be reasonable to reduce the overall costs of these shared services if demand is reduced for the service or if the costs are not comparable with the fair market value of similar services from third parties (or surrogate calculations of third party services). This documentation should be made available for all TECO and PGS rate cases all in Florida and filed at the outset of each rate case as an MFR.

4) TECO should make significant changes in its accounting system to more easily track, identify, and provide a proper audit trail for all affiliate transactions by each affiliate. TECO should have various expense subaccount balances that shows only the specific gross expense (not netted with other affiliate or non-affiliate transactions) it pays to each affiliate for each year. This account should include only "affiliate" transactions and not any other accounting transactions related to the regulated utility operations. Likewise, similar to expense transactions, TECO should have a separate contra expense account balance with

similar tracking, showing all "credits" or reductions to expense accounts by affiliate (with no other accounting transactions related to regulated utility operations). These accounts should allow TECO or third parties to identify and know the amount of gross expense that TECO pays to an affiliate at any point in time for services provided to TECO by affiliates, and the same information should exist for any contra expenses (or revenues) related to services that TECO provides to other affiliates.

5) The amounts in item (4) above should reconcile to TECO's FERC Form 1 affiliate diversification data. The FERC Form 1 affiliate diversification data should separately show all affiliate "expense" amounts by affiliate and major services/agreements, all "contra-expense" amounts by affiliate and major services/agreements.

6) TECO should require an external management audit of TECO's role as central service provider and the review of the affiliate transaction process, including Emera and Tampa/TECO provision of corporate support and shared services to TECO and other affiliates – including allocation factors and inputs. All of the previous concerns that I have raised should be subject to review.

This management audit should not be performed by a Certified Public Accounting firm or its management/consulting audit affiliate that has had a prior or current relationship with Emera, TECO, or any affiliate. Preferably, TECO should not hire a Certified Public Accounting firm or its management/consulting audit affiliate because these entities establish a confidential internal "materiality factor" for such engagements. The "materiality factor" establishes a dollar value which the firm believes is material enough to require disclosure for accounting errors, incorrect allocations, improper allocation factors and other dollar-value or policy impacts. These firms do not disclose their materiality factors and these firms can have a vastly different opinion of what constitutes a material error or impropriety from their accounting perspective, compared to the perspective of materiality by regulators in a rate case proceeding.

7) Separate and specific monthly invoices should be sent by TECO to affiliates which identify and document only the centralized shared services (and related contra expenses or revenues) provided by TECO to affiliates. Likewise, monthly invoices should be sent by affiliates to TECO which identify and document only the centralized shared services expenses for services provided to TECO by the affiliate. All gas purchases transactions should be billed separately by all affiliates, and not comingled or netted in billings with centralized services.

8) Emera and TECO should establish a formalized written set of internal controls and safeguards to address the accounting for centralized services, cross-subsidy

issues, objectivity and independence, and other potential concerns regarding the centralized service provider.

9) Emera should perform an internal audit of TECO's role as centralized service provider, along with a review of affiliate transactions, allocation processes, issues related to cross-subsidy, the treatment of the take-back of shared services by affiliates and other important matters. The internal audit report, recommendations, and the results of implemented recommendations be filed with the Commission and available to interested parties.

IX. ABSENCE OF SUPPORT FOR AFFILIATE ALLOCATION PROCESS

Q. DID THE COMPANY'S TESTIMONY ADDRESS AFFILIATE ISSUES IN ANY DETAIL?

A. No. TECO witness Mr. Richard Latta's direct testimony (now adopted by Mr. Chronister) addresses affiliate transactions very briefly[45] at a high level and he does not address any specific affiliate transaction amounts or impacts upon TECO. Also, Mr. Latta's testimony does not refer to any affiliate-related adjustments proposed by TECO, and he does not state that TECO relied on the 2025 Budget affiliate expenses (and adjusted allocation factors) for purposes of adjusting the revenue requirement in this rate proceeding.

TECO witness Mr. Chronister's direct testimony did not address affiliate transactions, does not refer to any affiliate-related adjustments proposed by TECO, and

[45] Latta direct, pp. 51-55.

C23-2235

does not state that TECO relied on the 2025 Budget affiliate expenses (and adjusted allocation factors) for purposes of adjusting the revenue requirement in this rate proceeding.

The direct testimony of TECO does not provide adequate supporting documentation to address or justify the significant levels of affiliate expenses on TECO's books, either for the 2023 calendar year or for the 2024/2025 Budget period.

Q. WAS THE COMPANY ABLE TO PROVIDE INDEPENDENT OR OBJECTIVE STUDIES TO SUPPORT THE REASONABLENESS OF ITS ALLOCATIONS AMONG AFFILIATES?

A. No. TECO states that Emera, TECO, and affiliates have not performed analysis or studies to address the reasonableness of affiliate expenses.[46] Therefore, there is no internal or external prepared independent or objective analysis or studies to support the reasonableness of affiliate expense transactions on TECO's books. There is no study that compares TECO's affiliate transactions to the market or industry benchmarks to determine if the transactions are reasonable.

X. SUMMARY OF OPC AFFILIATE CHARGE ADJUSTMENTS

Q. IS IT CLEAR WHETHER TECO'S AFFILIATE EXPENSES ARE REFLECTED ON A 2025 BUDGET BASIS OR BASED ON AN ADJUSTED DECEMBER 31, 2023, BASIS?

[46] TECO's response to OPC's Second Set of Interrogatories and PODs, Interrogatory No. 73 and POD No. 44.

A. It is not clear because there are conflicting responses by TECO to OPC Interrogatories, but I have assumed a worst case scenario that TECO increased its affiliate expenses to the higher level included in the 2025 Budget. Therefore, all of my adjustments are to the 2025 Budget affiliate expenses (and the underlying 2025 Budget allocation factors and inputs). If this is incorrect, then it may be necessary ~~for~~ to correct my testimony.

TECO states that it did not make any adjustments for affiliate charges in the Administrative and General accounts (which is the account where most of the affiliate expenses are recorded), and it cited to a net balance of affiliate transactions in the Administrative and General account that is related to the actual December 31, 2023, book balance.[47] This response appears to indicate that TECO did not make any affiliate transactions adjustments and did not use 2025 Budget amounts for affiliate expenses.

However, TECO appears to provide a conflicting response to another OPC Interrogatory that indicates it ~~indicates~~ did make adjustments to affiliate expenses based on the 2025 Budget when it states, "The allocation factors reflected on the Excel spreadsheet impact the 2024/2025 budget amounts through the budgeting of credits to FERC account 922 for the portion that is allocated to affiliates."[48]

Despite TECO's conflicting and unclear responses, I am adjusting from the higher level of affiliate expenses included in the 2025 Budget.

Q. PLEASE SUMMARIZE CONCERNS AND UNDERLYING RATIONALE FOR YOUR ADJUSTMENTS TO AFFILIATE EXPENSES.

[47] TECO's response to OPC's Fifth Set of Interrogatories and PODs, Interrogatory No. 99 and POD No. 75.
[48] TECO response to OPC Tenth Set of Interrogatories and Eleventh PODs, Interrogatory No. 177 and POD No. 136.

My concerns and underlying rationale for adjustments are summarized below.

1) Emera, Tampa Electric, TECO, nor any other affiliate has performed, or caused to be performed, any independent or objective review or analysis of affiliate transactions to determine that the amounts charged from Tampa Electric to TECO (and other affiliates) are reasonable, rely on proper cost allocation methods, and are consistent with the market or benchmarks in the industry.[49]

2) TECO has failed to meet a reasonable burden of proof regarding affiliate expenses charged from Tampa Electric to TECO by failing to provide certain requested supporting documentation and calculations to address the validity and reasonableness of the amounts.

3) TECO provided information with some schedules showing certain types of affiliate expenses in Canadian currency, while other types of affiliate expenses were provided only in U.S. currency. It was not until late May 23rd that TECO was able to reconcile and provide these affiliate expenses in consistent U.S. currency.[50]

4) A flawed MMM allocation method is used to allocate expenses to TECO, and this is merely a three-factor formula and not a "Massachusetts Method" because two of the three inputs vary from the actual Massachusetts Method.

[49] TECO response to OPC Second Set of Interrogatories and PODs, Interrogatory No. 73 and POD No. 44.
[50] TECO response to OPC Tenth Set of Interrogatories and Eleventh Set of PODs, Confidential response to Interrogatory No. 179 and POD No. 138.

5) The flawed MMM uses Net Income as one of its three equally weighted allocation factors. Net Income is not a proper allocation factor (or driver of costs) because there is no cost-causation (or correlation) between Net Income and the affiliate expenses that it is being used to allocate. Net Income is not an allocation factor in the original Massachusetts Method, and Net Income is not an industry standard or best practice allocation factor based on my experience. I made adjustments to allocations to TECO by revising the MMM allocation factor.

6) PGS took back Procurement shared services in-house that were previously allocated via centralized shared services and the residual expenses previously allocated to PGS are now shifted to TECO, along with significant increasing Procurement expenses – and TECO has unfairly become the guarantor of recovery for all residual expenses although this is not supported by cost-causation. These Procurement expenses are adjusted to a more reasonable level when I substituted a net plant investment allocation factor for TECO's Purchase Order Spend allocation factor.

7) Some allocation factors used to allocate expenses to affiliates for the actual 2023 calendar year financials are based on 2022 inputs (one year in arrears), and these inputs should be updated to actual 2023 inputs at the minimum when reasonable.

C23-2239

8) Certain allocated shared service expenses use an incorrect allocation factors in Excel spreadsheets that do not agree with the allocation factors in the underlying supporting workpapers showing the calculations, and I have adjusted these allocation factors.

9) No internal audits have addressed affiliate transactions from at least calendar years 2019 to 2024.[51]

XI. ADJUSTMENT BCO-1: UNSUPPORTED AFFILIATE EXPENSES

Q. PLEASE EXPLAIN ADJUSTMENT BCO-1 REGARDING EMERA ALLOCATED EXPENSES TO TECO?

A. I will explain this adjustment below the following Confidential table:

Table 2
Adjustment BCO-1

	A	B	C	D	E	F
Ln	Emera and Emera Services, Inc. Services	Corporate Support Services	Canada $ Actual 2023	US $ Actual 2023	TECO Budget 2025	OPC Adjustment
1	Emera	Direct		$ 11,117,821	$11,075,000	
2	Emera	TSI Allocated	$1,158,628	$ 858,561	Not provided	$ (858,561)
3	Emera	Allocated	$4,132,878	$ 3,062,525	Not provided	
4	Emera Services, Inc.	Direct		$ 4,134,342	$ 4,421,000	
5	Total Direct and Allocated		$ 5,291,506	$ 19,173,249	$15,496,000	
6	Direct Charges Not Subject to Adjustment		$ -	$ 15,252,163	$15,496,000	
7	Allocated Charges Subject to Adjustment		$ 5,291,506	$ 3,921,086		
8	Ostrander/OPC Adjustment					**$ (858,561)**

[51] TECO response to OPC Second Set of PODs, POD No. 43.

The Confidential table above shows total direct and allocated expenses from Emera and Emera Services, Inc. for calendar years 2023 and the 2025 Budget, except I was not able to locate 2025 Budget amounts for Emera "TSI allocated" and Emera "allocated" expenses to TECO. Therefore, I have removed Emera expenses allocated to TECO Services, Inc. in 2023 of $.90 million using the 2023 balance, although this could potentially overstate or understate this adjustment depending upon the related amount of 2025 Budget expense used by TECO in the revenue requirement calculation. This adjustment is shown at Exhibit BCO-2. The bottom line adjustment amount and the reasons for the adjustment are not Confidential. However, the calculation and how it was determined from the amounts in the Confidential table above are Confidential. For example, the $.90 million adjustment amount is not specifically identified in any TECO Confidential or public responses to interrogatories or PODs, but how that amount was calculated from the Confidential table above is considered Confidential, although no party would know how the amount is calculated without access to all of the underlying Confidential amounts in the table above. Therefore, the adjustment that is publicly disclosed is not determinable by parties without access to Confidential information.

The total Emera direct and allocated charges to TECO for 2023 is $19.20 million, although the Emera direct charge of $11.10 million and the Emera Services, Inc. direct charge of $4.10 million (a total of $15.30 million) do not impact TECO expenses because these charges are treated as an Accounts Receivable accounting entry. Thus, the remaining Emera expenses allocated

C23-2241

to TECO in 2023 is $3.90 million and I have removed $.90 million of the TECO Services, Inc. related allocated expenses.

TECO states that TECO Services, Inc. will be legally dissolved in 2024, with seconded employees that work for Emera affiliates to be moved from TECO Services, Inc. to TECO, although this will not result in an increase in expenses on TECO's books because direct charges only result in a debit to FERC Account 146 (Accounts Receivable) to recognize the affiliate receivable, and no FERC expense accounts are charged.[52]

TECO states this Emera charge is a direct expense that does not impact expense accounts, so the dissolution of TECO Services, Inc. will not result in a change in expense amounts for TECO. I disagree. This amount is an Emera allocated expense that will impact TECO's expenses, so I have made an adjustment to remove this expense. Although I have translated this expense adjustment amount to U.S. currency of $858,561,[53] the related Canadian currency amount of $1,158,628 is shown as the total expense allocated from Emera to TECO Services, Inc. at TECO's response to Interrogatory No. 61 and Confidential POD No. 37.[54]

In addition, I have removed this expense because TECO has not provided any supporting documentation to show that it is reasonable, efficient, and not duplicative

[52] TECO's response to OPC's Eighth Set of Interrogatories and Ninth Set of PODs, Interrogatory No. 156 and POD No. 119.

[53] This amount is translated to US currency by dividing the Canadian currency amount by a factor of 1.3495.

[54] TECO's response to OPC's Second Set of Interrogatories and PODs, Interrogatory No. 61 and Confidential POD No 37, including file "CONF_POD_2-37" that included Confidential Excel spreadsheets "Emera Affiliate Allocations – Annual Summary 2023 041724 Highlighted.xlsx", "Emera Affiliate Allocations – Annual Summary 2022 041724 Highlighted.xlsx", "Emera Affiliate Allocations – Annual Summary 2021 041724 Highlighted.xlsx", and "(BS 16847) Emera Affiliate Allocations – Detailed Total 2021-2023_Highlighted.xlsx."

C23-2242

of existing TECO expenses to transfer the expenses of dissolved TECO Services, Inc. to TECO operations in 2024. If TECO Services, Inc. is being dissolved, it would appear to defeat any benefits of cost cutting to merely transfer all expenses of a dissolved company to TECO operations. TECO has not explained why it is reasonable to dissolve TECO Services, Inc. and why it is reasonable to transfer its expenses to TECO. This does not appear to accomplish anything that is beneficial for either TECO Services, Inc. or TECO. TECO has failed to meet its reasonable burden of proof regarding the justification for transferring and recovering these TECO Service, Inc. expenses through TECO operations in future years. Therefore, the Commission should adopt my adjustment to remove these expenses.

Q. DID TECO PROVIDE ALL OF THE REQUESTED SUPPORTING DOCUMENTATION AND CALCULATIONS FOR THE AFFILIATE EXPENSES ADDRESSED IN ADJUSTMENT BCO-1?

A. No. OPC issued numerous interrogatories and production of documents to gain access to supporting documentation, calculations, and allocation methods applicable to all affiliate transactions (both direct and allocated/assessed amounts), and TECO did provide this requested information for some affiliate charges, but not for all of the affiliate charges subject to Adjustment BCO-1. For example, the following interrogatories and production of document requests all asked for information where TECO should have provided the supporting documentation for Emera and Emera Energy Services, Inc. affiliate expenses. Further, I will expound in detail below on the multiple discovery requests propounded that demonstrate TECO had ample opportunity to provide the relevant supporting documentation and calculations.

<u>OPC's Second Set, Interrogatory No. 61 and Production of Documents No. 37</u>

This interrogatory is subtitled "Top Down Allocation of Affiliate Costs to TECO," and requested the allocated/assigned affiliate expenses from Emera (Parent) TECO for years 2019 to 2023 (and budgeted amounts), starting with Emera (Parent Company) and showing the allocated costs through all intermediate companies (service companies) through the final allocation to TECO. Also, this interrogatory requested all affiliate costs be provided by function (Corporate, Human Resources, etc.) and type (payroll, rent, etc.) as allocated to TECO and all affiliates, and requested all allocation factors and the underlying calculations and supporting documentation (along with additional information requested). This interrogatory was very precise and specific in its request for "allocated" and "assigned" (meaning all allocated, direct, and other) affiliate costs from Emera and other affiliates to TECO, along with supporting documentation and calculations. The related POD asked for all supporting documentation regarding the rationale, calculations, and conclusions for Interrogatory No. 61.

TECO's response to Interrogatory No. 61 provided no explanation of documents or information being provided, but referred to its objections in related POD No. 37 and referred to the Confidential documentation provided with POD No. 37. TECO's response to POD No. 37 repeated the same numerous objections that it includes with almost all of its responses to OPC Interrogatories and PODs related to affiliate issues and also referred to the provided Confidential document at "CON_POD_2_37." CON_POD_2_37 included an Excel spreadsheet titled, "(BS 16846) Emera Affiliate Allocations – Annual Summary 2023_Highlighted.xlsx" (cited as "Confidential BS 16846"); similar files were provided for years 2021 and 2022).

It is important to point out that for some unexplained reasons, the amounts at BS 16846 were provided in Canadian currency, although other TECO responses to OPC Interrogatories and PODs addressing allocations from TECO (or other affiliates) were all provided in U.S. currency.

Q. DID TECO FAIL TO TIMELY IDENTIFY AND PROVIDE A RECONCILATION FROM CANADIAN TO U.S. CURRENCY FOR AFFILIATE EXPENSE?

A. Yes. I addressed this in a prior section of my testimony, so I will not repeat all of the same concerns again.

Q. HAS TECO PROVIDED COPIES OF AGREEMENTS FOR THE EMERA AND EMERA ENERGY SERVICES, INC. DIRECT EXPENSES?

A. No. I am not aware that TECO has provided copies of the Emera Energy Services, Inc. "Asset Management Agreement" or any agreements or contracts supporting the Emera "Corporate Support Services." Although the provision of these agreements or contracts by themselves may not adequately satisfy my request for "supporting documentation and calculations" for these expenses,[55] it would be a helpful starting point.

[55] My conclusion would be different if the agreements and contract documents include the supporting documentation and calculations for these expenses charged to TECO.

TECO's Schedule No. C-31, page 24 of 35 (BS 91) refers to three documents entitled Emera "Services Agreement" with Tampa that were all shown as being renewed in 2023, along with another "Services Agreement." The MFR information does not mention a termination or renewal date. Similarly, TECO's Schedule No. C-31, page 25 of 35 (BS 92) refers to two Emera Energy Services, Inc. documents entitled "Services Agreement," with one shown as being renewed in 2023 and one shown as being effective until 2029, along with a "Asset Management Agreement" that is shown as being effective until 2026. All of these documents are relevant and important, particularly to review changes in terms and costs from prior agreements. TECO's failure to provide these existing documents is another example of TECO's failure to meet a reasonable burden of proof regarding certain affiliate charges.

XII. ADJUSTMENT BCO-2: ADJUST TAMPA ELECTRIC AFFILIATE EXPENSES

Q. PRIOR TO EXPLAINING ADJUSTMENT BCO-2, DO YOU HAVE OTHER CONCERNS REGARDING AFFILIATE ALLOCATIONS THAT YOU HAVE NOT ADDRESSED AS AN ADJUSTMENT AT THIS TIME?

A. Yes, my concerns are as follows. OPC's Second Set of Interrogatories and PODs, Interrogatory No. 65 and POD No. 41 requested certain financial and other data from 2020 to 2024 for various foreign and U.S. affiliates (including TECO) to which both Emera and Tampa Electric allocate corporate and shared services expenses based on financial and other data used as inputs in the allocation factors. The amount of affiliate expenses allocated to TECO is also affected by the amount of affiliate expenses allocated to other foreign and U.S. affiliates based on the various financial and other data used in the allocation factors.

Thus, it is necessary to review these allocation factor inputs to determine if expenses allocated to TECO are reasonable and not overstated, based on related allocations to other affiliates. TECO's response objected to providing this financial/data allocation input information for other foreign and U.S. affiliates but TECO did provide a high level explanation of the various affiliates without providing any financial or other data. There are no publicly available sources for me to obtain this data to confirm the reasonableness of allocation factors and the related allocation of expenses to other affiliates that also impacts the residual allocation to TECO. Therefore, this continues to be a concern and could result in additional adjustments to affiliate expenses.

Q. PLEASE EXPLAIN ADJUSTMENT BCO-2.

A. I will explain this adjustment below the following table.

Table 3
<u>Summary of Adjustment BCO-2</u>

	A	B	C
	(In Millions)		OPC
	Tampa Electric Expenses	OPC	Adj.
Ln	Allocated to TECO	Adjs.	No.
1	Replace Net Income MMM Factor/Update Other Factors	$ (0.40)	2.1
2	Remove One-Half of Corp. Responsibility Costs	$ (3.60)	2.2
3	Revise Human Resources Headcount Factor	$ (0.20)	2.3
4	Revise Procurement Factor to Net Plant Investment	$ (1.30)	2.4
5	Total OPCAdjustments	$ (5.50)	

C23-2247

Tampa Electric records all Shared Services expense and then allocates these expenses to TECO and other affiliates based on various allocation/assessment factors, and this resulted in 2023 Shared Service expense of $50.60 million[56] being allocated to TECO and $22.20 million allocated to other affiliates.[57]

The actual 2023 TECO Shared Services expense of $50.60 million and the related 2025 Budget expense of $51.90 million (reflected in TECO's revenue requirement) are the amounts that were subject to my review and related adjustments. For all four of my adjustments, I began with the 2025 Budget Shared Services expense balance of various departments subject to my adjustment and I applied revised allocation factors for Adjustment Nos. 2.1, 2.3, and 2.4. For Adjustment No. 2.3, I reduced the 2025 Budget Corporate Responsibility department costs by one-half after applying my revised MMM factor to this expense.

I do not agree with the 2025 Budget amount for each of the shared service department expenses, and if other OPC witnesses make rate case adjustments to these amounts then I will need to revise my calculations. Also, using the 2025 Budget amounts for purposes of my affiliate adjustments, was a compromise between TECO's increased level of affiliate expenses and the offsetting impact of my adjustments related

[56] The Total shared service expenses for 2020, 2021, 2022, and 2023 are from TECO's response to OPC Fifth Set of Interrogatories and PODs, Interrogatory No. 95 and POD No. 71, Excel spreadsheets tiled, "(BS 19213) Shared Services Schedule 2020.xlsx", and similar spreadsheets at BS 19214 (Shared Services for 2021), BS 19215 (Shared Services for 2022), BS 19216 (Shared Services for 2023). Total shared service expenses for the 2025 Budget are from TECO's response to OPC Second Set of Interrogatories and PODs, Interrogatory No. 63 and POD No. 39, Excel spreadsheet titled "(BS 17337) TEC SS Budget Schedule 2025.xlsx." Also, TECO's response to OPC Sixth Set of Interrogatories and PODs, Interrogatory No. 103 and POD No. 81, provided file POD_No._81 which included a spreadsheet titled, "(BS 19597) Shared Services Schedule 2023.xlsx.", which is the same Shared Services Schedule for 2023 that was provided in response to POD No. 71 as BS 19216 cited above in a request for Management Reports regarding affiliate transactions.

[57] TECO allocates Shared Services expenses to the other affiliates PGS, NMG, SeaCoast, TECO Partners, Inc., TECO Gemstone, Inc., and TECO Energy, Inc. – although not every type of Shared Service expense is allocated to each affiliate and different types of allocation factors impact the amounts allocated to all affiliates.

to allocation factors and other issues. Adjustment BCO-2 results in a total reduction in TECO Shared Services expense of $5.50 million with detailed calculations provided at Exhibit BCO-2, and I have summarized the four different types of adjustments below:

1) **Adjustment BCO-2.1** – TECO's MMM includes three equally weighted allocation factors of Net Income, Revenue, and Net Assets. I have removed the Net Income factor and replaced it with a 2023 Headcount factor and updated some of the remaining Revenues and Net Asset factors. For those 2023 TECO Shared Service expenses that I adjusted and which were allocated using the MMM, I have applied my revised MMM allocation factor percentage and reduced the related amount of Shared Service expenses allocated to TECO.

2) **Adjustment BCO-2.2** – First, I adjusted the 2025 Budget expenses for "Corporate Responsibility" and "Other Corporate" departments using my revised MMM allocation factor. Second, I disallowed 50% of this remaining expense after applying my revised MMM allocation factor. These total "Corporate Responsibility" department expenses represent the single largest department expense comprising TECO's actual 2023 and 2025 Budget Shared Service expenses. Also, TECO has not provided any supporting documentation to address these broad and undefined expenses. TECO has not provided any documentation to prove these corporate expenses are not duplicative of other corporate-type expenses or that they are not excessive. Also, TECO'S response to OPC's Fifth Set of Interrogatories and PODs, Interrogatory No. 95 and POD No. 71 provides

additional detailed information showing shared service allocated costs by expense categories of labor, outside services, employee expenses, and other. For the Corporate Responsibility expenses, an unusually significant amount of expenses were identified as "Other", including $9.60 million (64%) of the total $14.90 million that are subject to allocation to TECO and all affiliates. This emphasizes my concerns with these significant broad and vague corporate overhead/direct expenses because TECO has not disclosed or provided any important specific information about these expenses. I will continue my review, but if additional information is not available to validate these expenses then it may be reasonable to disallow all of these expenses. Simply put, TECO failed to meet its burden to justify these costs.

3) **Adjustment BCO-2.3** – I revised and updated TECO's Headcount allocation factor for various 2025 Budget Human Resources department expenses, and this caused a reduction in the allocation factor and the related Human Resources expenses allocated to TECO.

4) **Adjustment BCO-2.4** – These 2025 Budget Procurement department shared service expenses are allocated to TECO using a "Purchase Order Spend" allocation factor. The total amount of Procurement department expenses have increased significantly in recent years along with the Purchase Order Spend allocation factor for TECO. Also, PGS has reduced its reliance on Procurement shared services by taking back some of these functions in-house. The combination of all these factors

has resulted in TECO incurring almost all Procurement expenses (among all other affiliates) in 2023 and for budgeted periods 2024 and 2025. In prior sections of my testimony, I explained the problems with excessive allocations of Procurement expense to TECO, and I will rely on those arguments without repeating them in this section of my testimony. Finally, I have substituted a more accurate and reasonable allocation factor to be applied to Procurement expense, and this "Net Plant Investment" allocation factor results in a reduction in Procurement expenses allocated to TECO.

Q. PLEASE EXPLAIN HOW THE MMM ALLOCATION FACTOR IS USED TO ALLOCATION TAMPA ELECTRIC SHARED SERVICE EXPENSES TO TECO AND AFFILIATES.

A. The MMM is a three-factor formula comprised of an equal weighting of three different factors/inputs which drive various Shared Service expenses to TECO and other affiliates as follows: [58]

1) Net Income – Net income after taxes and other income/expenses;
2) Operating Assets – Total operating assets less cash (and less goodwill and acquisition adjustment); and
3) Revenues – Total operating gross revenues.

The MMM that is used for allocating expenses to TECO and other affiliates in 2023 is illustrated in the table below. The MMM allocation method uses inputs that

[58] TECO Energy, Inc. CAM, effective January 1, 2020, p. 20. Per TECO's response to OPC's First Set of Interrogatories and PODs, Interrogatory No. 8 and POD No. 8, and also TECO's response to OPC's Second Set of Interrogatories and PODs, Interrogatory No. 58 and POD No. 34.

are one year in arrears, which means that Tampa Electric uses 2022 financial inputs/drivers in its MMM calculation that is used to allocate actual 2023 Shared Service expenses as illustrated in the table below.

Table 4
TECO's MMM for 2023 Financial Period (With 2022 Inputs)

	2022 Tampa Electric Company	2022 Peoples Gas System	2022 New Mexico Gas	2022 SeaCoast Gas Transmission	2022 Total
Actual as of 12/31/2022					
Total Revenues *	$ 2,522,891	$ 655,835	$ 577,923	$ 27,672	$ 3,784,321
Revenue	66.67%	17.33%	15.27%	0.73%	100.00%
Net Income **	$ 457,871	$ 82,238	$ 39,184	$ 16,299	$ 595,592
Net Income	76.88%	13.81%	6.58%	2.74%	100.01%
Operating Assets ***	$ 12,052,656	$2,467,333	$ 1,535,370	$ 191,362	$16,246,721
Operating Assets	74.19%	15.19%	9.45%	1.18%	100.01%
Blended Actual Rate	72.6%	15.4%	10.4%	1.6%	100.00%

The above MMM table shows the 2022 financial inputs for Revenue, Net Income, and Operating Assets for TECO and each applicable affiliate, and the percentage of each affiliate's financial input to the total financial input is calculated, such as TECO's 66.67% ($2,522,891) of Revenues compared to total Revenues for all affiliates ($3,784,321). For each affiliate, the percentages of all three financial inputs are averaged, and the average MMM factor of 72.60% is used to allocate expenses to TECO.

The MMM factor is applied as follows. For example, assume total Treasury department shared service hypothetical expenses of $5.0 million before allocation to any of the affiliates. TECO's 72.60% MMM factor is multiplied by the $5.0 million of total Treasury expenses, and the resulting Treasury expense of $3,630,000 is allocated to TECO, total Treasury expense of $5.0 million is also multiplied by the PGS MMM factor of 15.40% to allocate $770,000 to PGS' books, NMG is allocated $520,000 of Treasury expense ($5.0M x NMG MMM factor of 10.40%), and SeaCoast is allocated $80,000 of Treasury Expense ($5.0M x SeaCoast MMM factor of 1.60%).

Q. WHAT ARE YOUR CONCERNS WITH THE MMM AND RELATED FINANCIAL INPUTS USED TO ALLOCATE TAMPA ELECTRIC EXPENSES TO AFFILIATES?

A. I am not opposed to a three-factor MMM method that uses reasonable inputs. However, the original Massachusetts Method (which is not modified) uses the three financial inputs of: 1) Operating Revenue; 2) Payroll; and 3) Net Book Value of Tangible Capital Assets (plus Inventory). This means the MMM used in this proceeding is not really a "modified" Massachusetts Method because only one component (Revenues) from the original Massachusetts Method is used for allocating expenses. I consider the MMM used by Tampa Electric to be more of a "three-factor" allocation method, and it is not proven to be a reasonable surrogate of the Massachusetts Method. I am not contesting the MMM's two factor inputs of Revenues and Operating Assets. However, I have significant concerns regarding the Net Income input and I have substituted a Headcount input factor.

Q. WHAT ARE YOUR CONCERNS WITH THE NET INCOME ALLOCATION FACTOR?

A. My primary concerns with the Net Income allocation factor are discussed below.

1) <u>No Cost Causation Link</u>.

First, Net Income is a flawed allocation factor because there is no cost-causation link between Net Income and the Shared Services that are driven to various affiliates using this factor. There is no direct, indirect, or reasonable correlation between the size and variability of Net Income in relation to the Shared Service expenses that are allocated using the Net Income factor. In other words, if one particular affiliate has a high Net Income (or low Net Income), that does not mean that same affiliate has a corresponding high amount of Shared Service expenses, or does not mean that a particular affiliate should be allocated a corresponding higher amount of Shared Services based on its high Net Income.

There are many examples of companies that have a high Net Income and a low level of expenses, Net Income does not necessarily move in the same direction as expenses because there is no consistent, reasonable, or direct correlation. The MMM applied by Tampa Electric is flawed because the affiliate with the highest Net Income is allocated the highest amount of Shared Service expense. However, this approach is not even supported by common sense. If Company A has a higher Net Income than a comparable Company B, there is a reasonable likelihood that Company A has a higher Net Income because it is more efficient and has less expenses than Company B. There are many examples of publicly traded companies with a high Net Income, while having correspondingly low operating expenses.

2) <u>Net Income is Unduly Biased to Allocate Greater Costs to TECO For Recovery in Rate Case.</u>

Second, this Net Income factor is unduly biased and drives an unreasonably high level of Shared Services to TECO compared to other affiliates. TECO's Net Income allocation factor is the largest of its three allocation factors (and the largest among allocation factors of all other affiliates), with Net Income allocation factor of 76.88%, Operating Assets factor of 74.19%, and Revenue factor of 66.67%, resulting in a final weighted factor of 72.58%. The Net Income factor is arbitrary and unduly biased toward driving a greater amount of Shared Service expenses to TECO, which are then subject to recovery from customers in rate case proceedings. The Massachusetts Method does not use Net Income as an allocation factor because of the concerns that I have expressed.

3) <u>Not Supported by Industry Best Practices</u>.

Third, a Net Income allocation factor is not supported by industry best practices based on my experience. I am not aware that utility companies routinely or primarily use Net Income as an allocation factor to allocate expenses among affiliates. TECO has not provided any documentation showing that Net Income is a reasonable allocation factor and that it is commonly used by utilities to allocate expenses among affiliates.

4) <u>Not Supported by the Criteria in TECO's CAM.</u>

The TECO Energy, Inc. CAM that is effective for this rate case states that cost allocation factors (or drivers) should be based on the criteria of: 1) cost causative; 2) measurable; 3) objective; 4) stable or predictable; and 5) consistent and applicable.[59] The TECO Energy, Inc. CAM does not cite to or specifically state that the Net Income allocation factor meets all of these criteria. In fact, the Net Income factor fails to meet most of these criteria, in that it is not cost causative, it is not objective, it is not necessarily stable or predictable, and it is not consistent. While, I agree that Net Income is measurable, the Net Income allocation factor fails the test of a reasonable allocation factor by most criteria and it should not be adopted by the Commission in this proceeding.

Q. WHY DO YOU PROPOSE TO SUBSTITUTE A HEADCOUNT ALLOCATION FACTOR FOR THE NET INCOME ALLOCATION FACTOR?

A. Headcount is a reasonable allocation factor and should be used as the third MMM allocation factor. Arguably, Headcount is a better allocation factor than a "Payroll" factor, because a Payroll factor may include significant short and long-term incentive expenses, along with other types of costs that may be routinely disallowed by state regulatory agencies. The failure to account for these disallowed items can result in an incorrect and excessive allocation of costs to affiliates (resulting in excessive costs being recovered in rates from customers).

In fact, Headcount is the most prevalent allocation factor used by Tampa Electric (and TECO Energy, Inc.) to allocate Shared Services expense among TECO and other affiliates. TECO's Excel spreadsheet (POD No. 81) that shows Shared

[59] TECO Energy, Inc. CAM, effective January 1, 2020, p. 2. Per TECO's response to OPC's First Set of Interrogatories and PODs, Interrogatory No. 8 and POD No. 8, and also TECO's response to OPC's Second Set of Interrogatories and PODs, Interrogatory No. 58 and POD No. 34.

Services expenses allocated between TECO and all affiliates uses the Headcount factor to allocate costs to about 65 of the 86 total different departments – by far the most commonly used allocation factor. Although no allocation factor is perfect, I believe that a Headcount allocation factor is superior to a Net Income allocation factor, and TECO's predominant use of a Headcount factor supports my argument.

Q. DID YOU ALSO UPDATE THE MMM TO REFLECT MORE CURRENT ALLOCATION FACTORS (VERSUS TECO'S 2023 MMM THAT USES 2022 ALLOCATION FACTOR INPUTS)?

A. Yes. I used TECO's 2024 budgeted MMM Revenues for TECO and PGS, and I used the December 31, 2023, (per Annual Report) Revenues for NMG and SeaCoast because I did not have any other data available from an independent source. I used the December 31, 2023 (per Annual Report) Operating Asset amounts for TECO, PGS, NMG and SeaCoast.

Q. HOW DOES YOUR REVISED MMM COMPARE TO TECO'S MMM FOR 2023 AND 2025 BUDGET?

A. The table below compares the OPC and Company MMM allocation factor inputs and the total blended allocation factor. For illustrative purposes in the table, I used the Company's "2023" allocation factors, but because TECO adjusted its revenue requirement using its "2025 Budget" allocation factors, my actual affiliate expense adjustments begin with TECO's 2025 Budget allocation factors (and not its 2023 allocation factors). Although I compare my revised MMM allocation factor of 67.62%

(for TECO) to the Company's 2023 MMM allocation factor of 72.58% in the table below, the Company actually used a 72.07% for its 2025 Budget allocations. I have used the OPC-proposed blended allocation factor to revise the allocation of 2025 Budget Shared Service expenses to TECO in Adjustment BCO-2.1, as will be addressed next.

Table 5
Comparison of OPC and TECO's 2023 MMM Allocation Factors

	A	B	C	D	E	F	G
				Allocation Factor Percentages			
Ln	Parties	Factor	TECO	PGS	NMG	SeaCoast	Total
1	Ostrander/OPC	Revenues	67.93%	19.15%	12.20%	0.72%	100.00%
2	Ostrander/OPC	Headcount	62.40%	18.87%	17.50%	1.23%	100.00%
3	Ostrander/OPC	Assets	72.54%	18.90%	7.41%	1.16%	100.01%
4	Blended Allocation Factor		**67.62%**	**18.97%**	**12.37%**	**1.04%**	100.00%
5	TECO (2023 with 2022 inputs)	Revenues	66.67%	17.33%	15.27%	0.73%	100.00%
6	TECO (2023 with 2022 inputs)	Net Income	76.88%	13.81%	6.58%	2.84%	100.11%
7	TECO (2023 with 2022 inputs)	Assets	74.19%	15.19%	9.45%	1.18%	100.01%
8	Blended Allocation Factor		**72.58%**	**15.44%**	**10.43%**	**1.58%**	

Q. PLEASE EXPLAIN YOUR CALCULATION OF REMAINING ADJUSTMENTS BCO-2.2, BCO-2.3, and BCO-2.4.

This is a multi-part calculation with supporting detailed calculations shown at Exhibit BCO-2.

First, for Adjustments BCO-2.2, I used the total 2025 Budget expenses of $10.60 million for Corporate Responsibility Shared Service expense and applied my revised TECO MMM allocation factor of 67.62%, and this reduced the amount allocated to TECO from $7.70 million to $7.20 million, a reduction of $.50 million. Next, I disallowed 50% of the revised $7.20 million Corporate Responsibility expense, resulting in an adjustment of $3.60 million. If the Commission does not accept the

50% disallowance of Corporate Responsibility expenses, but accepts my revised MMM factor, this would be an expense reduction of $.50 million for this part of my adjustment.

Second, for Adjustment BCO-2.3, regarding certain Human Resource department expenses subject to a Headcount allocation factor, I revised TECO's Headcount allocation factor from 71.97% for the 2025 Budget (a factor of 71.51% was used by TECO for 2023) to my revised Headcount allocation factor of 61.70% to reflect updated and more reasonable allocation factors – and this reduced these Human Resource-related expenses by $.20 million (Adjustment BCO-2.3). This is more of a routine adjustment that does not need much explanation because it relies on actual updated headcount information instead of TECO's unsupported budgeted headcount.

Third, for Adjustment BCO-2.4, regarding certain Procurement department expenses subject to the "Purchase Order Spend" allocation factor, I revised TECO's Purchase Order Spend factor from 94.06% for the 2025 Budget (a factor of 89.40% was use by TECO for 2023) to my revised allocation factor of 74.43% based on the 2023 "Net Plant Investment" of each applicable affiliate. This reduced these Procurement-related expenses by $1.30 million (Adjustment BCO-2.4).

Q. PLEASE EXPLAIN YOUR CONCERNS REGARDING THE SUBSTANTIVE INCREASES IN PROCUREMENT EXPENSES AND ALLOCATION FACTORS FOR TECO BEGINNING IN 2023 RELATED TO ADJUSTMENT BCO-2.4.

C23-2259

A. First, I addressed my substantive concerns with the significant unsupported increases in the total and TECO-allocated amount of Procurement expenses (and related allocation factors) in a comprehensive manner[60] at "Section VII. Concerns with TECO as a Centralized Service Company", and I will not repeat all those concerns again at this section. The concerns that I addressed at Section VII are a significant factor in my adjustment of the Procurement allocation factor at this section. In addition, I explained how PGS reduced its reliance on Procurement shared services by taking back some of these functions in-house (and reducing its allocated expenses from Tampa Electric), although TECO has become saddled with almost all residual Procurement expenses because TECO has failed to responsibly control, or justify, these increasing levels of centralized service expenses.

Second, the primary concern is the substantive Procurement shared services allocation factor of 89.40% for 2023 and 94.06% for the 2025 Budget, which appears excessive when compared to almost any other shared service allocation factor applicable to TECO. This concern exists in part because the Procurement Purchase Order Spend allocation factor is not proven to be compliant with the TECO allocation factor criteria of: a) cost causative; b) measurable; c) objective; d) stable or predictable; and e) consistent and applicable. The Procurement Purchase Order Spend allocation factor of 89.40% for 2023 allocates $4.80 million of Procurement department expenses to TECO, and only allocates $43,000 to NMG and $525,000 to PGS.

To test the reasonableness of these relatively immaterial allocations to NMG and PGS, I determined the 2023 average annual payroll cost per TECO employee is

[60] I addressed my concerns in a comprehensive manner in about six pages.

between $85,000 to $97,000. I may be over-simplifying to some degree by treating the NGM and PGS Procurement allocated expenses of $43,000 and $525,000 as entirely payroll costs. However, with this assumption, this would mean that the NMG $43,000 allocated Procurement expense is only equal to about one-half of one employee's salary for the 2023 year, and the PGS $525,000 Procurement allocated expense is only equal to about six employees for the 2023 year.

Given that TECO was allocated $4.8 million of Procurement expense in 2023, it does not appear reasonable that NGM and PGS could run their Procurement departments at these substantially reduced cost levels. I understand that PGS has taken back some Procurement functions in-house and PGS has a reduced reliance on Procurement shared service expenses. Since this is the case, then a more reasonable response would be for TECO to reduce its Procurement staffing and costs to reflect the take-back of Procurement functions by NMG and PGS – instead of requiring TECO to pick up all the residual costs of the Procurement department (that were previously incurred by NMG and PGS) via an increased allocation factor.

It is not reasonable for TECO to effectively pay above market-based competitive prices for Procurement services (resulting from the residual Procurement costs previously incurred by PGS that are now allocated to TECO). If both NMG and PGS took back some of these Procurement services in-house instead of paying for these centralized services, this may mean that TECO's prices for Procurement expense are excessive and not competitive with the market. This means that the undue shifting of these residual costs to TECO results in it being the guarantor for recovery of such excessive that may exceed competitive market prices for this service. This end result

C23-2261

is unfairly beneficial to TECO and unfairly detrimental to customers, because TECO can recover these potential above-market Procurement costs from customers via the rate case process.

Q. WHY IS YOUR NET PLANT INVESTMENT ALLOCATION FACTOR BETTER THAN A PURCHASE ORDER SPEND ALLOCATION FACTOR?

A. The Procurement function should be responsible for purchasing and contracts related to both capitalized net plant investment and outside services (which could include expensed and capitalized amounts). Therefore, I believe that a Procurement allocation factor based on net plant investment for TECO (and each affiliate receiving this service) is a reasonable driver of these expenses. My net plant allocation factor for TECO of 74.43% is more consistent with TECO's other 2023 allocation factors such as the 2023 MMM factor of 72.58% and the headcount factor about 73%. I do not believe there should be a significant deviations in primary allocation factors unless TECO can prove a strong cost-causation link between the allocation factor and the cost that it is driving.

Q. DO YOU HAVE ADDITIONAL EXHIBITS ATTACHED TO YOUR TESTIMONY?

A. Yes, I do. I have Exhibit BCO-2 which contains the calculations that support my adjustments described earlier in my testimony. I also have Exhibit BCO-3 that is composed of the pertinent TECO discovery responses that informed my review and analysis.

Q. WILL YOU IDENTIFY THOSE CONCERNS AND MATTERS THAT REMAIN OPEN OR UNRESOLVED DUE TO OUTSTANDING INTERROGATORIES AND PODS, RECENTLY PROVIDED INFORMATION, (OR INFORMATION PENDING OR NOT PROVIDED FOR OTHER INTERROGATORIES AND PODS)?

A. I have a number of existing concerns that may need to be addressed via supplemental testimony, pending further supporting documentation that is necessary and is being obtained from TECO through current or pending data requests. I will identify some of the primary remaining concerns.

First, I have outstanding concerns regarding Mr. Chronister's deposition responses received May 24, 2024 in the form of late filed exhibits and related Excel spreadsheets. Because OPC has been preparing its prefiled direct testimony it has not had adequate time to fully evaluate all of these responses and data for their impact on this rate case. This information could impact adjustments to affiliate transactions.

For example, "LFE_No 2_Chronister_bates.pdf" and related "LFE 2 Excel files" provided information for the first time regarding the Modified Massachusetts Method allocation factors applicable to Emera. Even though OPC Interrogatory No. 62 and POD No. 38 requested all of the allocation factors and supporting documentation and calculations used to allocate costs to TECO. TECO's April 22, 2024, response to OPC's Second Set of Interrogatories and PODs, Interrogatory No. 62 and POD No. 38, included only objections, and has never provided any allocation factors subject to this Interrogatory and POD. However, TECO has provided allocation factor information in response to several other Interrogatories and PODs with information trickling in on a periodic basis. Although all of the allocation factor information should have been provided by April 22, 2024, in response to Interrogatory No. 62 and POD No. 38. TECO is still providing allocation factor information per the May 24, 2024, deposition information from Mr. Chronister. Thus, allocation factor information is still being provided by TECO over thirty days from the intended due date, and the current time constraints for filing direct testimony has not allowed OPC to adequate time to fully evaluate the deposition information from Mr. Chronister.

Second, there are also other concerns raised by Mr. Chronister's deposition that are part of continuing or new concerns that will require follow-up interrogatories and PODs, and which could impact affiliate transaction adjustments.

Third, as I identified in the body of my testimony, there are concerns that TECO has not provided the related underlying formal agreements (and any other supporting calculations and supporting documentation) between TECO and both Emera and Emera Services, Inc. regarding Emera's Corporate Support Service charges to TECO of $11.10 million and Emera Services, Inc. charges to TECO of a net negative amount of ($4.10 million). If additional information is not forthcoming, then it may be necessary to address these concerns by additional adjustments to affiliate transactions.

Fourth, as I identified in the body of my testimony, it was not clear from conflicting TECO responses to interrogatories whether the revenue requirement calculation reflects affiliate transaction expense using the: 1) December 31, 2023, balances with no TECO adjustments; or 2) 2025 Budget balances with updated adjusted balances. My testimony made adjustments to affiliate expenses from the 2025 Budget amounts, but if the December 31, 2023, balances were used it may be necessary to update and revise my affiliate expense adjustments.

Fifth, I have continuing concerns regarding the lack of documentation regarding Corporate Responsibility expenses, and this issue is subject to further review and adjustment.

Also, there are other Interrogatories and PODs that remain to be answered, and OPC may need to address these matters.

Q. DOES THE ABSENCE OF A COMMENT OR ADJUSTMENT REGARDING CERTAIN AFFILIATE ISSUES MEAN YOU AGREE WITH TECO'S POSITIONS ON THE MATTER?

A. No, just because I did not offer a comment or adjustment on certain other affiliate issues does not mean that I am in agreement with TECO's position on such matters. Further, I reserve my right to supplement my testimony upon receipt of pertinent discovery.

Q. DOES THIS COMPLETE YOUR PREFILED DIRECT TESTIMONY?

A. Yes, at this time. However, the compressed procedural schedule in this proceeding for filing Intervenor testimony has limited the time to complete OPC's investigation into the issues and effects of those issues on the Company's petition. Consequently, it is my understanding that OPC reserves the right to file supplemental testimony to fully address these issues and effects of those issues, if necessary.

C23-2265

BY MR. REHWINKEL:

Q Mr. Ostrander, did you prepare three exhibits to accompany your testimony, BCO-1 through 3?

A Yes.

Q Do you have any changes or corrections to those exhibits?

A No.

MR. REHWINKEL: Mr. Chairman, those exhibits have been identified in the Comprehensive Exhibit List as Exhibits 60 through 62.

BY MR. REHWINKEL:

Q Mr. Ostrander, do you have a summary of your prefiled testimony?

A Yes, I do.

Q Could you give that at this time?

A Yes.

Thank you, Mr. Chairman and Commissioners. The purpose of my testimony is to address affiliate transactions. I have also proposed some related adjustments and policy recommendations in that regard.

The review of affiliate transactions is important because the affiliate transactions need to properly resent -- represent expenses on the company's books to ensure that the regulated utility, TECO, is not subsidizing the unregulated affiliate or -- affiliate or parent company, Emera.

In addition, it's important that affiliate transactions be properly reflected on the books to make sure that they do not include any duplicate corporate and other overhead costs which might normally or properly be retained on the books of the corporate parent, Emera. Therefore, affiliate transactions are very important.

Now, I will address the absence of the documentation to support TECO's affiliate transactions in its direct testimony.

The company's direct testimony of Mr. Chronister and Mr. Latta, now adopted by Mr. Chronister, addresses affiliate transactions very briefly and at a high level, and does not address any specific affiliate transaction amounts or impacts upon TECO.

TECO was asked to provide copies of all studies or documentation to address the reasonableness of its affiliate transaction amounts, and TECO was unable to provide this information. Thus, there is no studies prepared by TECO or for any consultants hired by TECO to show that its affiliate transactions are reasonable.

Next I will explain the corporate structure and affiliate expenses allocated to TECO.

TECO is a public utility operating within the state of Florida, and it includes an electric division called Tampa Electric, with Emera as the parent company. My testimony, at times, refers to both TECO and Tampa Electric interchangeably, and in most cases, I don't make an important distinction between those entities. However, it is important to understand that Tampa Electric is the entity that allocates and assigns significant operating expenses to TECO that impact the revenue requirement in this rate case. Therefore, my testimony addresses expenses allocated to TECO from two primary entities, and that's TECO -- I am sorry, Tampa Electric and Emera, the parent company.

Tampa Electric assigns by far the most significant of affiliate expenses to TECO, and these amounts have increased over time. For actual 2023 calendar results, Tampa Electric allocated total expenses of about 73 million to all affiliates, with 50.6 million, or 70 percent, allocated to TECO. And the 2025 projected budget expenses were an increase of 51 point -- an increase of 51.9 million, which is an increase of 1.3 million over 2023 actual. Emera allocates a smaller amount of affiliate expenses to TECO, with amounts of about 14.9 million.

Next, I will summarize some of my transaction

-- some of my policy concerns with affiliate transactions.

The TECO Services, Inc., as a nonregulated affiliate, was the initial centralized service provider since about January 2014, and continued in that capacity after Emera acquired TECO in 2016. However, in 2019, TECO filed a waiver request with the Federal Energy Regulatory Commission to state that TECO would now become the centralized service provider in place of TSI.

There are inherent problems with TECO serving as both the centralized service provider and as a regulated utility. It is my experience, that centralized service providers are not typically regulated utilities, but are, instead, nonutility and unregulated affiliates whose primary role is just flowing through allocated expenses to affiliates. I am not aware of any CSP that is also a regulated utility for a major energy provider.

In addition, TECO's FERC waiver request stated that it could provide centralized services more efficiently than the prior centralized service provider, TSI, and that this would simplify the corporate structure. But TECO has not provided any documentation to support this, and, in fact, numerous expenses have increased over time, including procurement expenses. I make various recommendations in that regard.

Also, I will skip now to my adjustment amounts. I have reduced affiliate expenses by 6.3 million. Adjustment BCO-1 removes 0.9 million of Emera related affiliate expenses. Adjustment 2.1 removes a larger amount of expenses, and in total, is about four million.

And in this factor, I have replaced the modified Massachusetts Method with a more reasonable headcount factor, and updated other factor inputs to reduce the allocation factor from 72.58 to 67.62.

The problems with the modified Massachusetts Method is that it uses income as an allocation factor. A true Massachusetts method does not use net income as an allocation factor because it is not a cost causative factor.

In addition, it appears that TECO might have used the net income factor, because it allocates a significant higher percentage of cost than -- to TECO than do the other allocation factors. For example, the net income factor allocates 77 percent of expenses to TECO, and the others are in the 67 to 74 percent range.

Thank you very much for allowing me to present this summary.

CHAIRMAN LA ROSA: Thank you.

MR. REHWINKEL: Mr. Ostrander is available for cross-examination.

CHAIRMAN LA ROSA: Great. Thank you.

Florida Rising/LULAC.

MR. MARSHALL: No questions.

CHAIRMAN LA ROSA: FIPUG.

MR. MOYLE: No questions.

CHAIRMAN LA ROSA: FEA.

CAPTAIN GEORGE: No questions. Thank you.

CHAIRMAN LA ROSA: Florida Retail.

MR. LAVIA: No questions.

CHAIRMAN LA ROSA: Walmart.

MS. EATON: No questions.

CHAIRMAN LA ROSA: TECO.

EXAMINATION

BY MR. WAHLEN:

Q I just have one question.

Would you agree, subject to check, that the proper pronunciation of Emera is Emera not Imera?

A Yes.

Q Okay. Thank you.

CHAIRMAN LA ROSA: Staff.

MR. SPARKS: No questions. Thank you.

CHAIRMAN LA ROSA: Commissioners, do we have any questions?

Seeing none, OPC, I will send it back to you for redirect.

MR. REHWINKEL: Mr. Chairman, the Public Council would move Exhibits 60, 61 and 62 into the record.

CHAIRMAN LA ROSA: Is there objection?

Seeing none, show them entered into the record.

(Whereupon, Exhibit Nos. 60-62 were received into evidence.)

CHAIRMAN LA ROSA: Are there any other exhibits?

Seeing none, Mr. Ostrander, thank you. You are excused.

MR. REHWINKEL: Thank you, Mr. Chairman.

THE WITNESS: Thank you.

CHAIRMAN LA ROSA: Thank you.

(Witness excused.)

MR. REHWINKEL: We may be at a point where we need to suspend the OPC presentation because Mr. Woolridge is in a deposition, so --

CHAIRMAN LA ROSA: Sure.

MR. REHWINKEL: -- we would turn it over to another intervener.

CHAIRMAN LA ROSA: Sure. I would ask Florida

Rising/LULAC, are you ready with your witnesses?

MR. MARSHALL: If I could just have one minute, Mr. Chairman. Our witness stepped out to do a call because he did not realize he was about to, but he should be right outside in the lobby.

CHAIRMAN LA ROSA: Yeah. Understood. We can take a couple seconds.

MR. SPARKS: Mr. Chairman, while we are waiting, just so we are not wasting time, and also just for clarity and perhaps an abundance of caution, per the discussion last night, Sierra Club has been --

CHAIRMAN LA ROSA: Real quick --

MR. SPARKS: -- excused, but we just want to make sure that they are --

CHAIRMAN LA ROSA: Real quick. I just want to make sure that we are not in an official break, right? So let me call us back into order.

MR. SPARKS: Oh, well, we -- this can kind of be an aside.

CHAIRMAN LA ROSA: Yeah, let's go ahead.

MR. SPARKS: We just want to make sure that Sierra Club's testimony and exhibits get moved into the record, and if we are waiting on witnesses to show up, we might be able to take care of that.

CHAIRMAN LA ROSA: Okay. So, yes, I guess there is a question on whether Sierra Club's -- I am sorry, I wasn't -- I was following along. I was looking at you, but I was following along with who is coming next. So, please, if you don't mind repeating that.

MR. SPARKS: Yeah. I believe we excused them with the expectation that when their turn came, we would move their testimony and exhibits into the record.

CHAIRMAN LA ROSA: Okay.

MR. SPARKS: But since the turn is a little bit up in question right now, we just thought we might take the opportunity.

CHAIRMAN LA ROSA: Okay.

MR. MOYLE: Do you need a motion, as a courtesy to them, to move it into the record?

MR. SPARKS: Staff can make that motion.

Staff would move to have the testimony of Sierra Club Witness Glick inserted into the record as though read.

CHAIRMAN LA ROSA: Okay. Is there objection? Seeing no objections, show that that testimony is entered into the record.

(Whereupon, prefiled direct testimony of Devi

Glick was inserted.)

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

Petition for Rate Increase by Tampa Electric Company	)))))))	**DOCKET NO. 20240026-EI**

DIRECT TESTIMONY OF

DEVI GLICK

ON BEHALF OF SIERRA CLUB

June 6, 2024

C32-3120

TABLE OF CONTENTS

C32-3121

LIST OF EXHIBITS

DG-1:	Resume of Devi Glick
DG-2:	TECO response to Sierra Club 1st IRRs
DG-3:	TECO response to Sierra Club 2nd IRRs
DG-4:	TECO response to Sierra Club 3rd IRRs
DG-5:	TECO Ten-Year Site Plan, January 2024 – December 2033
DG-6:	U.S. Department of Energy and Tampa Electric Company. 2000. *The Tampa Electric Integrated Gasification Combined-Cycle Project: An Update*. Topical Report Number 19
DG-7:	TECO response to SC IRR 1-8, Attachment (BS 28921) 2018 – 2023 GFP.xlsx
DG-8:	TECO response to SC IRR 31, Attachment (BS 28967) Sierra Club 1st Set 2024 - 2033 Firm Generators and RM IRR Q31
DG-9:	EPA Memorandum, Steam Electric Rulemaking Record – EPA-HQ-OW-2009-0819. Unit-Level Costs and Loadings Estimates for the 2024 Final Rule (DCN SE11756A1), April 22, 2024
DG-10:	EPA Memorandum, Steam Electric Rulemaking Record – EPA-HQ-OW-2009-0819. Generating Unit-Level Costs and Loadings Estimates by Regulatory Option for the 2024 Final Rule (DCN SE11756), April 22, 2024
DG-11:	NERC, 2023 State of Reliability Technical Assessment, June 2023
DG-12:	TECO response to SC IRR 8, Attachment (BS 28923) 2019 - 2023 Factor and Rates
DG-13:	Schlissel, D. 2017. *Using Coal Gasification to Generate Electricity: A Multibillion-Dollar Failure*. Institute for Energy Economics and Financial Analysis
DG-14:	U.S. EPA. 2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category (2024 Technical Memo), Attachment 1

DG-15:	Duke Energy, "Appendix F: Coal Retirement Analysis," 2023 Carolinas Resources Plan
DG-16:	Institute for Energy Economics and Financial Analysis, "Coal Use at U.S. Power Plants Continues Downward Spiral; Full Impact on Mines to be Felt in 2024," Nov. 2, 2023
DG-17:	Earthjustice, "Toxic Coal Ash in Florida: Addressing Coal Plants' Hazardous Legacy," May 3, 2023
DG-18:	U.S. Department of Energy, Loan Programs Office, Program Guidance for Title 17 Clean Energy Financing Program, May 19, 2023
DG-19:	C. Fong, D. Posner, and U. Veradarajan, "The Energy Infrastructure Reinvestment Program: Federal financing for an equitable, clean economy," RMI, February 16, 2024
DG-20:	C. Fong, D. Posner, and U. Varadarajan, "Maximizing the value of the energy infrastructure reinvestment program for utility customers," RMI, May 24, 2024

LIST OF TABLES

LIST OF FIGURES

C32-3125

1. INTRODUCTION AND PURPOSE OF TESTIMONY

Q Please state your name and occupation.

A My name is Devi Glick. I am a Senior Principal at Synapse Energy Economics, Inc. ("Synapse"). My business address is 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.

Q Please describe Synapse Energy Economics.

A Synapse is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission, and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government agencies, and utilities.

Q Please summarize your work experience and educational background.

A At Synapse, I conduct economic analysis and write testimony and publications that focus on a variety of issues related to electric utilities. These issues include power plant economics, electric system dispatch, integrated resource planning, environmental compliance technologies and strategies, and valuation of distributed energy resources. I have submitted expert testimony before state utility regulators in more than a dozen states.

In the course of my work, I develop in-house models and perform analysis using industry-standard electricity power system models. I am proficient in the use of spreadsheet analysis tools, as well as optimization and electric dispatch models. I have directly run EnCompass and PLEXOS and have reviewed inputs and outputs for several other models.

Before joining Synapse, I worked at Rocky Mountain Institute, focusing on a wide range of energy and electricity issues. I have a master's degree in public policy and a master's degree in environmental science from the University of Michigan, as well as a bachelor's degree in environmental studies from Middlebury College. I have more than 11 years of professional experience as a consultant, researcher, and analyst. A copy of my current resume is attached as Exhibit DG-1.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of Sierra Club.

Q Have you testified before the Florida Public Service ("Commission" or "FPSC")?

A No. But I testified as an expert before the Siting Board of the Florida Department of Environmental Protection in Tampa Electric Company ("TECO" or the "Company")'s 2018 site certification application for the Big Bend Power Station, DOAH Case No 18-2124EPP, where the Company sought to build a new combined-cycle power plant ("CC") at the site of Big Bend Units 1 and 2.

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

A The purpose of my testimony is to review the reasonableness of TECO's rate case requests for Polk Generating Station Unit 1 ("Polk 1") and Big Bend Generating Station Unit 4 ("Big Bend 4") based on the units' economics, the Company's capacity needs, and the Company's evaluation of alternatives. Specifically, I review the Company's request to convert Polk 1 to a simple-cycle combustion turbine ("CT") while retaining the ability to burn coal or petroleum coke ("petcoke") at the plant, and its request to continue operating Big Bend on coal and gas instead of retiring and replacing the unit. I review the likely environmental compliance costs the Company will incur at both units in the future, and the potential for utilizing funding available under the Energy Infrastructure Reinvestment ("EIR") program of the Inflation Reduction Act ("IRA") to finance replacing those plants and even refinance their remaining undepreciated balance.

Q How is your testimony structured?

A In Section 2, I summarize my findings and recommendations for the Commission.

In Section 3, I introduce TECO's coal plants at Polk 1 and Big Bend 4 and its capacity position and future needs.

In Section 4, I summarize TECO's request, in this rate case, to convert Polk 1 to a simple-cycle CT while retaining the ability to operate the unit on petcoke in the future by keeping integrated gasification combined-cycle ("IGCC") components online or in reserve. I highlight my concerns with the Company's plan to continue maintaining the IGCC infrastructure at the plant, despite TECO's decision not to use the infrastructure since 2018. I also discuss my concerns with the Company's lack of analysis of retirement and replacement of the unit as an alternative to its plan to convert it to a CT. I summarize my own analysis on the recent and projected economic performance of the unit and present my recommendations that TECO should, under all circumstances, retire the IGCC components as soon as possible, and further, should not spend ratepayers' money on converting the unit to a CT without conducting a thorough alternatives analysis.

In Section 5, I summarize TECO's rate case requests for Big Bend 4. I discuss my concerns with the Company's request to continue recovering the costs of operating the unit without proper analysis demonstrating that is the most economic option for ratepayers. I summarize my own analysis on the recent and projected economic performance of the unit. I outline my recommendations that TECO submit an application under the EIR program to the U.S. Department of Energy ("DOE") Loan Programs Office ("LPO") to finance clean energy replacement resources for Big Bend 4. This funding can also be leveraged to refinance the undepreciated balance of existing fossil resources. I recommend that TECO simultaneously perform an alternatives analysis for Big Bend 4, which should include the assumption that TECO would leverage the EIR loan to finance replacement resources and refinance the remaining balance of Big Bend 4.

Q What documents do you rely upon for your analysis, findings, and observations?

A My analysis relies primarily upon the workpapers, exhibits, and discovery responses provided by TECO, TECO's Ten-Year Site Plans ("TYSPs"), as well as publicly available data.

2. FINDINGS AND RECOMMENDATIONS

Q Please summarize your findings.

A My primary findings are:

1. TECO has not supported its request to continue operating Big Bend 4 on coal and to include the associated costs in rates.
2. Big Bend 4 has seen declining utilization and was uneconomic to operate during three out of the last five years. Company data indicates that the plant will continue to be uneconomic to operate going forward, especially when operated on coal.
3. TECO has indicated that it costs less to operate Big Bend 4 on gas than coal and has not justified its decision to continue burning coal at the plant for the express purpose of keeping the solid fuel equipment viable.
4. TECO has not used the integrated gasification ("IG") technology at Polk 1 to operate the unit on coal since at least 2018, and has not justified incurring substantial costs for ratepayers to retain that equipment, which is providing no value to ratepayers.
5. TECO has not provided analysis to support its request for approval of $80.5 million for the Polk 1 Flexibility Project to convert Polk 1 to a simple-cycle CT and include the associated costs in rates.
6. TECO has not provided analysis to support its request to retain at Polk the IG, steam turbine ("ST"), and heat recovery steam generator ("HRSG") technology—none of which are needed to operate the plant as a simple-cycle CT—as part of the Polk Flexibility project and to include the associated costs in rates. It is speculative to maintain these components to preserve the option to operate the unit on coal or petcoke when operation

on petcoke is not projected to be economic, and this switch would take a full year and incur costs that TECO has yet calculated.

7. TECO has not provided a current alternatives analysis to support its rate requests related to Polk 1 and Big Bend 4.
8. Complying with recently enacted federal environmental rules and standards governing power plants could cost TECO tens to hundreds of millions of dollars at Polk 1 and Big Bend 4.
9. TECO should not view undepreciated balances at either plant as a barrier to retirement, especially where TECO is incurring fixed and avoidable costs to maintain assets that are providing no ratepayer value.
10. TECO has not properly evaluated its option to leverage EIR program funding to retire and replace Big Bend 4. EIR funding available under the IRA can benefit both the Company and ratepayers in financing renewable projects, paying off the undepreciated balance on the legacy assets, and improving the company's credit ratings by restructuring its debt.

Q Please summarize your recommendations.

A Based on my findings, I offer the following recommendations:

1. The Commission should not allow inclusion in rates of any future spending on the IG technologies at Polk 1 and the Commission should require that TECO retire the IG components immediately (by the end of 2024), regardless of whether TECO converts Polk 1 to a CT.
2. The Commission should not allow TECO to convert Polk 1 to a simple-cycle CT, and include the associated costs in rates, unless TECO provides analysis demonstrating that converting the unit to a CT is lower cost than retiring the unit and replacing it with a clean energy portfolio.

3. If the Commission allows TECO to convert Polk 1 to a simple-cycle CT, it should require TECO to retire the ST and HRSG components (in addition to retiring the IG component).
4. The Commission should not allow TECO to continue to operate Big Bend 4 on coal and should require the Company to cease coal combustion and retire all solid-fuel-related equipment at the plant as soon as possible, and at the latest by the end of 2025.
5. The Commission should require TECO to evaluate how much spending on capital projects and environmental compliance is avoidable at both Polk 1 and Big Bend 4 by ceasing operations on coal and retiring all associated equipment. The Company should be required to justify to the Commission inclusion in rates of any costs incurred from decisions that deviate from what it finds to be most economic.
6. The Commission should not allow TECO to include in rates any operations and maintenance ("O&M") costs, nor any capital expenditures ("capex") at Polk 1 and Big Bend 4 that are avoidable with early retirement, without at least a proper economic analysis showing that continuing to rely on the unit costs less than alternatives.
7. The Commission should require TECO to submit an application to the DOE LPO for funding under the EIR program to replace Big Bend 4 with clean energy resources before September 2026, when applications are due. The Commission should require that TECO plan to use part of the EIR funding to refinance the plant balance at Big Bend 4.

3. INTRODUCTION TO TECO'S COAL ASSETS AND CURRENT CAPACITY POSITION

Q What is TECO proposing in this docket related to its coal capacity?

A TECO is seeking to include in rates $80.5 million for the Polk Flexibility Project[1] to convert Polk 1 to a CT and maintain the IGCC infrastructure, as well as the costs to operate and maintain Big Bend 4. This includes capex and O&M costs incurred during the test year.

Q What is the application test year?

A The application is based on the projected period of January 1, 2025 to December 31, 2025.[2]

Q Please provide an overview of Polk 1 and Big Bend 4.

A Polk 1 is a 220 MW[3] dual-fuel IGCC plant. The unit entered commercial operation in 1996[4] and is located in Polk County, Florida. The CC portion of the unit has a 1x1 configuration, meaning that it consists of one CT, one HRSG, and one ST.[5] Fuel is combusted in the CT to generate electricity. Hot exhaust gas then

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[1] Direct Testimony of Aldazabal at 44-46.

[2] Petition of Tampa Electric Company for approval of its 2020 Depreciation and Dismantlement Study and Capital Recovery Schedules (December 30, 2020) [hereafter "Petition"], at 5-6.

[3] Exhibit DG-5. TECO Ten-Year Site Plan, January 2024 – December 2033 [hereafter "2024 TYSP"], at 4.

[4] *Id*.

[5] Direct Testimony of Aldazabal at 10.

C32-3133

passes through the HRSG, which uses the waste heat to generate steam. The steam is fed to the steam turbine, which generates additional electricity.

Polk 1 also includes IG equipment, which can be used to generate syngas from coal. First, the gasifier oxidizes coal slurry, producing high-temperature syngas and slag.[6] The syngas is then cooled and passes through several scrubbing steps to remove contaminants, after which it is combusted in the CT in lieu of natural gas.[7] Steam from the syngas cooling process flows to the ST, supplementing steam produced by the HRSG.[8] Notably, TECO has not used the IG equipment at Polk since 2018; the unit was fueled exclusively by natural gas from 2019 to 2023.[9] Figure 1 below shows a process diagram of the layout of the IGCC equipment at Polk 1.

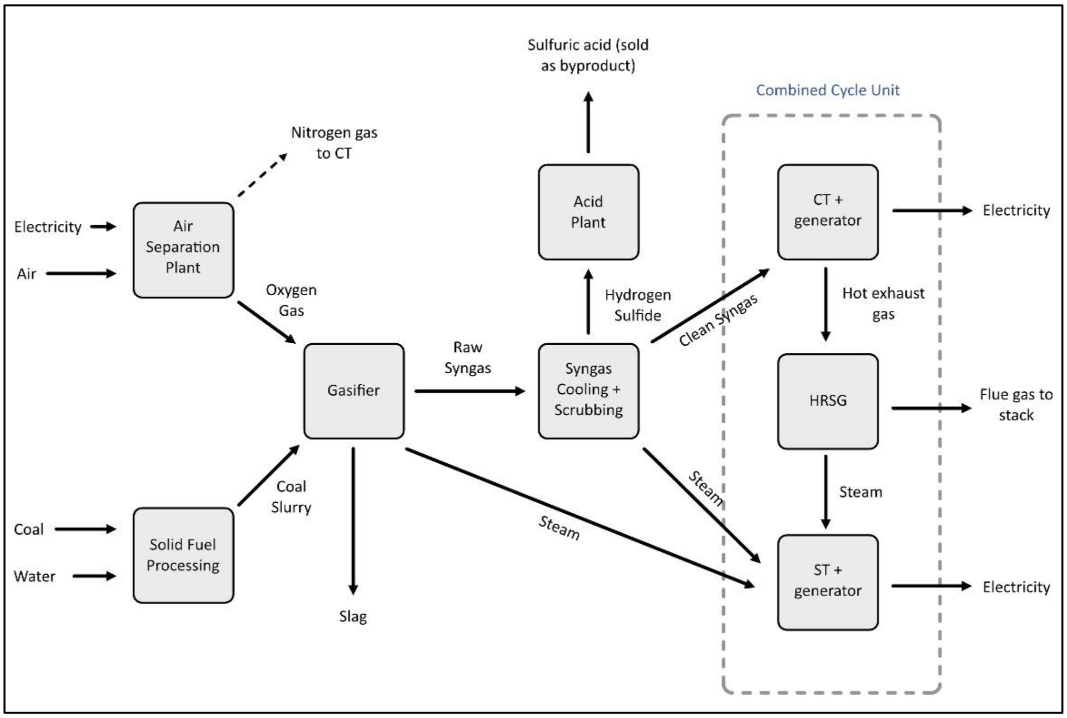
[6] Exhibit DG-6. U.S. Department of Energy and Tampa Electric Company. 2000. *The Tampa Electric Integrated Gasification Combined-Cycle Project: An Update*. Topical Report Number 19.

[7] *Id.*

[8] *Id.*

[9] Exhibit DG-7. TECO response to SC IRR 1-8, Attachment (BS 28921) 2018 – 2023 GFP.xlsx.

Figure 1. Polk 1 IGCC process diagram



Source: U.S. Department of Energy and Tampa Electric Company. 2000. The Tampa Electric Integrated Gasification Combined-Cycle Project: An Update. Topical Report Number 19; Holt, N. 2001. Integrated Gasification Combined Cycle Power Plants. Encyclopedia of Physical Science and Technology, 3rd edition.

Big Bend 4 is a 486 MW[10] dual-fuel coal-fired steam unit that can co-fire on gas. The unit entered commercial operation in 1985[11] and is located in Hillsborough County on Tampa Bay, adjacent to the community of Apollo Beach. Big Bend 4 has historically primarily used coal as a fuel,[12] but TECO is not renewing its coal supply contract and intends to purchase coal going forward on the spot market beyond December 31, 2024.[13]

[10] Exhibit DG-5. 2024 TYSP at 4.

[11] *Id.*

[12] Exhibit DG-7. TECO response to SC IRR 8, Attachment (BS 28921) 2018 – 2023 GFP.

[13] Exhibit DG-3. TECO response to SC IRR 79.

C32-3135

Q What is the undepreciated balance at each plant?

A At the end of 2023, the net book value of Polk 1 was $226 million and Big Bend 4 was $501 million (Table 1). Over half of the undepreciated balance at Polk 1 is from the gasification equipment, and the steam turbine and HRSG components of the CC unit account for an additional 24 percent. The CT accounts for only 20 percent.

Table 1. Undepreciated balance at Polk 1 and Big Bend 4

Unit	Equipment	Undepreciated Balance (Dec 2023)	Percent of Total Undepreciated Balance
Polk 1	TOTAL	$226,116,732	-
	CT	$45,077,367	20%
	ST and HRSG	$54,471,062	24%
	IG	$125,100,611	55%
	GSU	$1,467,692	1%
Big Bend 4	TOTAL	$501,265,153	-
	Boiler	$315,725,624	63%
	FGD	$143,665,876	29%
	SCR	$41,873,654	8%

Source: Company response to SC IRR 1-7, Attachments (BS 28915)#7 Big Bend 4 Coal NBV recovery and (BS 28916)#7 Polk 1 NBV recovery.

Q Why is the undepreciated balance for the plant significant?

A Utilities set depreciation schedules based on the anticipated useful life of an asset. TECO's most recent depreciation study from 2020 has TECO retiring Polk 1 in 2036 and Big Bend 4 in 2045.[14] Since 2020, market and regulatory forces have continued to change the economic viability of the coal plants. But TECO has not

[14] Petition at 39-1821, 45-47.

C32-3136

changed the retirement date nor depreciation schedule for Polk 1 and has only moved up Big Bend 4 a few years to 2040.

Utilities often view undepreciated plant balances as barriers to retirement before the currently planned retirement date. They may keep plants in rate base even when they are uneconomic or no longer providing value to ratepayers to ensure the undepreciated balance can be recovered. In this case, TECO has large undepreciated balances at both plants.

At Polk 1, 55 percent of the plant balance is for IG assets that have not been used since at least 2018, and another 24 percent is for ST and HRSG assets that will not be needed if the plant is converted to a simple-cycle CT. Three-quarters of the plant balance in rate base at Polk 1 is for assets that will be placed in reserve and not used to serve load if the plant is converted to a CT. Another 20 percent is for the existing CT, which TECO has stated it will replace with a new CT during the conversion. As I will discuss later in this testimony, TECO should retire the components of the plant that it does not need to operate as a CT. There are alternative rate mechanisms that the Company can use to address the balances.

Q What is the Company's plan for each of these coal units?

A According to TECO's most recent TYSP, the Company plans to operate Polk 1 until September 2036 and Big Bend 4 until January 2040.[15] It is unclear if this stated retirement date for Polk 1 takes into account the Company's stated plan to convert the unit to a CT.

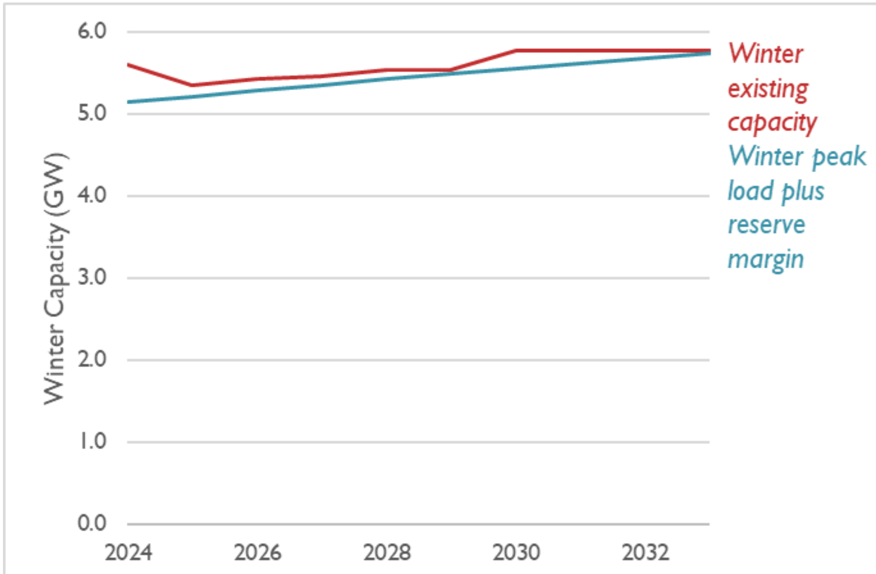
[15] Exhibit DG-5. 2024 TYSP at 4.

Q What is TECO's capacity position?

A TECO plans its system around a 20 percent reserve margin requirement.[16] While the Company must meet a minimum reserve margin of 20 percent, its actual resource mix can—and often does—result in a higher level of capacity and a reserve margin around 30 percent in the summer. Ratepayers are still required to fully finance this higher-than-needed amount of capacity. Based on the Company's current resource mix in its 2024 TYSP, between now and 2033, it projects a summer reserve margin of between 28 and 32 percent and a winter reserve margin of between 21 percent and 30 percent (Figure 2 and Figure 3).[17] This means that TECO currently has excess capacity and can retire older legacy fossil units that are costly and inefficient to operate.

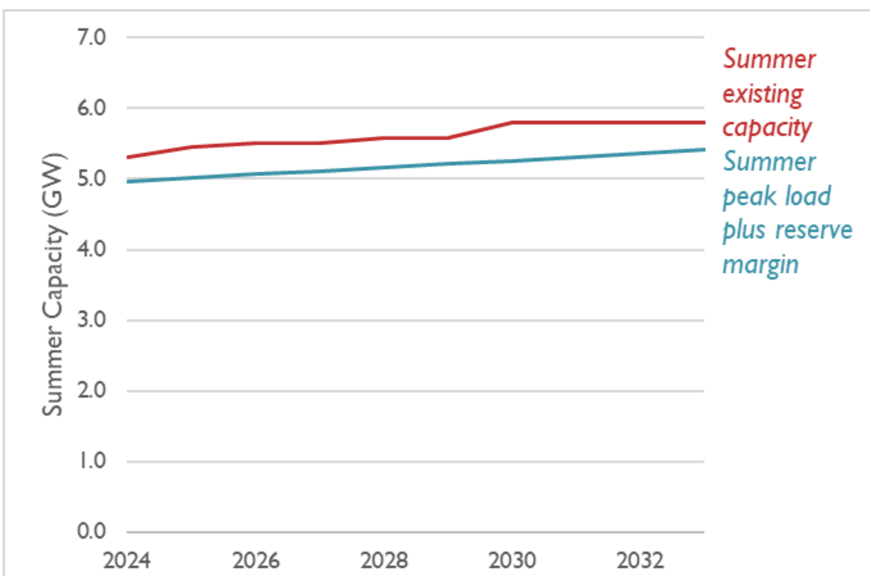
[16] *Id*. at 26.
[17] *Id*., Schedule 7.1 and 7.2.

Figure 2. TECO winter capacity position (existing and planned)



Source: TECO response to SC IRR 31, Attachment (BS 28967) Sierra Club 1st Set 2024 - 2033 Firm Generators and RM IRR Q31. Existing capacity includes planned builds from the TYSP.

Figure 3. TECO summer capacity position (existing and planned)



Source: TECO response to SC IRR 31, Attachment (BS 28967) Sierra Club 1st Set 2024 - 2033 Firm Generators and RM IRR Q31. Existing capacity includes planned builds from the TYSP.

C32-3139

4. <u>TECO's REQUEST TO RETAIN THE COAL-FIRING CAPABILITIES AT POLK 1 IS NOT JUSTIFIED BY ANALYSIS OR THE UNIT'S RECENT HISTORICAL AND PROJECTED ECONOMIC PERFORMANCE, NOR IS ITS REQUEST TO CONVERT POLK 1 TO A CT WITHOUT RETIRING THE IG, HRSG, AND ST COMPONENTS</u>

Q What is TECO requesting specifically for Polk 1 in this rate case?

A TECO is requesting permission to convert Polk 1 to a simple-cycle CT while retaining the ability to operate the plant on petcoke or a blend of petcoke and coal. Specifically, this would involve disconnecting the CT from the HRSG and ST, enabling it to operate as a simple-cycle rather than combined-cycle unit. In this conversion, TECO will be performing maintenance upgrades on the CT that amount to retiring the existing gas turbine, as it is no longer supported by the manufacturer, and replacing it with current technology.[18]

TECO proposes to retain the HRSG, ST, and IG equipment in long-term standby, even though they will not be in active use under this scenario.[19] The Company claims it wants to retain the ability to convert the plant to operate on petcoke—or petcoke blended with coal—in the event that these fuels become more cost-effective than natural gas in the future.[20] This means that the Company will likely not be using any of the existing generation components from the IGCC after the conversion, yet it is still requesting to retain them all in rate base. Further, in the event that natural gas prices spike much higher than petcoke prices, TECO would

[18] Exhibit DG-3. TECO response to SC IRR 90.
[19] Exhibit DG-2. TECO response to SC IRR 2; Exhibit DG-3. TECO response to SC IRR 89 (g).
[20] Direct Testimony of Aldazabal at 45.

have to first conduct an economic analysis to ascertain the cost of this conversion. TECO estimates that the conversion would take a year to complete.

Polk 1 currently has an accredited capacity of 220 MW in both the summer and winter.[21] Converting the unit to a CT would decrease its firm capacity contribution to 190 MW in the summer and 203 MW in the winter (equivalent to 14 and 8 percent reductions, respectively).[22]

i. TECO has not justified its request to retain the HRSG, ST, or IG equipment at Polk 1 after it converts the plant to operate as a simple-cycle CT

Q How has TECO been operating Polk in recent years?

A TECO has been operating the unit on natural gas exclusively since 2018, rather than on syngas generated from coal in the gasifier. This means that much of the plant, specifically the IG and associated equipment, has been in reserve since 2019.[23] As discussed above, this represents more than half of the remaining plant balance.

Q How much are ratepayers paying to maintain the unused parts of the plant?

A TECO ratepayers are paying around a quarter of a million dollars per year in ongoing maintenance costs, as well as around half a million per year for capital expenditures for the unused IG portions of the plant. In discovery, TECO estimated the annual cost to maintain the IG equipment (presumably, O&M costs)

[21] Exhibit DG-2. TECO response to SC IRR 31.
[22] *Id*.
[23] Exhibit DG-7. TECO response to SC IRR 1-8, Attachment (BS 28921) 2018 – 2023 GFP.xlsx.

at $260,000 per year (Table 2).[24] The Company did not provide data on whether there would be additional sustaining capital expenditures required to maintain the ST and HRSG in long-term storage, but it is likely this will be an expense. Elsewhere in discovery, TECO stated that it included $500,000 per year in ongoing capital expenditures in its test year rate base for the IGCC equipment, out of $13 million in total for Polk 1.[25]

Table 2. Annual maintenance costs for Polk 1 gasifier and associated equipment

Gasifier Equipment Category	Annual Maintenance
Total	$260,000
Coal & Slurry Handling	$2,000
Gasification Maintenance	$220,000
Acid Plant Maintenance	$1,000
Air Plant Maintenance	$37,000

Source: TECO response to SC IRR 89 (c). Bates number 30482.

Q Why hasn't TECO removed and retired the portions of the plant that are no longer in use, rather than just placing them in reserve and continuing to accrue costs related to their maintenance?

A TECO asserts that it wants to maintain the option to operate on coal or petcoke in the event that coal or petcoke prices become cost-competitive with natural gas prices.[26] But this is concerning because switching fuels requires a long-term fuel and planning strategy—neither of which TECO appears to have.

[24] Exhibit DG-3. TECO response to SC IRR 89 (c).
[25] Exhibit DG-2. TECO response to SC IRR 5.
[26] Direct Testimony of Aldazabal at 45.

At Polk 1, the IG equipment is currently in long-term standby, so it will take more than a year to bring it back online if TECO chooses to do so.[27] This means that TECO cannot utilize the IG to insulate ratepayers from volatility in the natural gas market. In 2022, TECO's own fuel price data shows that its average coal prices remained stable, while its gas prices spiked in response to the war in Ukraine.[28] Even still, TECO could not quickly make the decision to switch operation of the plant to coal during the gas price spike, and thus continued to rely on natural gas throughout that time. Ratepayers bore the brunt of those price spikes. Given that there is no indication the IG can provide a hedge for fuel price volatility as a reliability resource, the extraneous equipment should be retired.

Additionally, as I discuss below, once Polk is converted to a simple-cycle CT, switching Polk between gas and petcoke will be a long-term planning decision—not a short-term operational decision. TECO would need to regularly conduct long-term resource planning analysis to determine whether to make a switch, and it is unclear how TECO plans to do that.

Q Could TECO realistically switch Polk to petcoke during a future gas price spike?

A No. TECO estimates that re-enabling petcoke gasification at Polk 1 would take approximately one year.[29] Enabling petcoke usage would require bringing the gasification block (including solid fuel processing, air separation unit, gasifier, and acid plant) and steam cycle components (including HRSG, ST, and

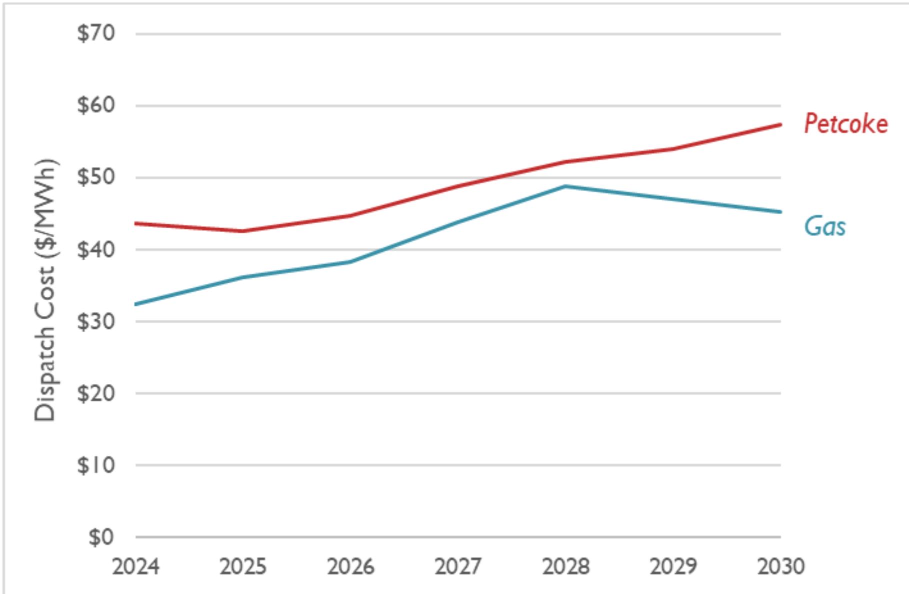
[27] Exhibit DG-4. TECO response to SC IRR 92.
[28] Exhibit DG-2. TECO response to SC IRR 8 (l).
[29] Exhibit DG-2. TECO response to SC IRR 3 (d).

condensate system) out of long-term standby.[30] In addition, certain gas turbine components, such as the combustion system, could require modification to re-establish compatibility with syngas.[31] TECO did not provide a cost estimate for this undertaking,[32] but cited the "extensive capital investment" required by the HRSG and ST as one reason not to continue operation of the plant in combined-cycle mode today.[33]

The year-long lead time and cost of reactivating the gasification equipment at Polk 1 means TECO would have to believe that there are reasonable and likely scenarios under which operation on petcoke will be less costly over the long term. But TECO has presented no evidence of any likely future conditions where it believes this will be true. And in fact, TECO's assertion that it may operate Polk 1 on petcoke in the future is contrary to its own projections of dispatch costs at Polk (Figure 4). Last, as a reliability resource, Polk 1's firm capacity represents a small percentage of TECO's winter firm capacity, and Polk 1 can in any case run on gas. The Company has therefore not justified that the IG assets are used and useful and that ratepayers should continue paying ongoing capital expenditures to maintain them.

[30] Exhibit DG-3. TECO response to SC IRR 89 (g).
[31] *Id.*
[32] Exhibit DG-2. TECO response to SC IRR 3 (c).
[33] Exhibit DG-3. TECO response to SC IRR 89 (i).

Figure 4. TECO projection of cost to generate electricity at Polk 1 on petcoke compared to natural gas



Source: TECO response to SC IRR 89(e).

Q What other motivation might TECO have for maintaining the full IGCC equipment at Polk?

A As discussed above, TECO is likely motivated by a desire to keep the plant in rate base and to continue recovering undepreciated plant balance with a rate of return. If the plant is determined to be no longer "used and useful"[34] then TECO runs the risk of not recovering its costs from ratepayers for this equipment.

[34] Fl. Statues Chapter 366.06 (1), available at: http://www.leg.state.fl.us/statutes/index.cfm?App_mode=Display_Statute&Search_String=&URL=0300-0399/0366/Sections/0366.06.html.

C32-3145

Additionally, TECO noted that it is considering carbon capture and storage ("CCS") at Polk,[35] although the Company has not performed an analysis comparing the costs of this option with the cost of simply retiring the unit.[36] Because Section 45(q) of the federal tax code offers credits per ton of carbon captured, CCS tends to be more cost-effective—although even then, it is often less cost-effective than renewable alternatives—for units that operate at a high capacity factor. TECO has indicated that it is evaluating how CCS would enable Polk 1 to operate beyond 2032 as a combined-cycle unit. Elsewhere in its documents, TECO states that potential reasons to reactivate the HRSG and ST include "Hydrogen, Carbon-capture, Syngas, or other opportunit[ies]."[37] However, TECO has not clearly stated what its CCS plans are, nor has it evaluated the costs of CCS in detail. This surface-level speculation is certainly not justification for keeping costly components online, especially those that would likely incur additional environmental compliance costs (see Section 5(iii) below).

Q Does the undepreciated balance, or the possibility of future CCS, justify maintaining the unused gasifier block and ST/HRSG at Polk?

A No. Regarding the undepreciated plant balance, there are alternative ways to address the undepreciated balance that can mitigate ratepayer impacts. For example, this can be done through the creation of a regulatory asset. A regulatory asset allows the utility to retire a plant with an undepreciated balance remaining and transfer the balance to a sort of black box asset. The remaining balance remains in rate base and is amortized over the course of however long its payment provides benefits to customers—generally a timeframe that is shorter than the

[35] Exhibit DG-2, TECO response to SC IRR 43 (a); Direct testimony of Stryker at 34.
[36] Exhibit DG-2. TECO response to SC IRR 43 (b).
[37] Exhibit DG-3. TECO response to SC IRR 89 (i).

original asset life but beyond the retirement date. Here the Commission can decide what terms it will allow the utility to recover—whether it is just the capital investment and debt, or the full rate of return.

Regarding CCS, it does not justify the cost and risks it imposes on ratepayers. The Company would be better off retiring the unused equipment and using its capital to build out commercially available options, such as solar photovoltaic ("PV") and battery energy storage systems ("BESS"), to meet its energy needs while reducing emissions. The biggest risk with CCS is cost overruns. TECO provides no information about avoiding the possibility of cost overruns. While the 45(q) tax credit provides financial support for CCS projects that capture a sufficient quantity of carbon dioxide, the level of uncertainty around the cost for these types of retrofits is much greater than for existing non-emitting technologies, such as solar PV and BESS. Given the capital costs of CCS projects, TECO could be facing hundreds of millions to even billions of dollars of potential overages in terms of expenditures. For example, Southern Company's attempt to construct an IGCC unit with a CCS plant at Kemper resulted in costs that were three times the initial project estimate (from $2.5 billion to $7.5 billion)[38] before the Mississippi Public Service Commission ultimately pulled the plug on the project and ordered Mississippi Power Company to continue to operate the plant on just natural gas.[39] TECO has provided no analysis or assurances demonstrating that a similar project at Polk 1 would not face similar cost overruns to keep a much smaller unit online.

[38] Kristi Swartz, "Southern Co.'s clean coal plant hits a dead end," *EnergyWire* (June 22, 2017), available at https://subscriber.politicopro.com/article/eenews/1060056418.

[39] Kristi Swartz, "The Kemper project just collapsed. What it signifies for CCS," *EnergyWire* (October 2021), available at https://www.eenews net/articles/the-kemper-project-just-collapsed-what-it-signifies-for-ccs/.

Lastly, CCS requires considerable energy to run itself. Retrofitting a plant with CCS will reduce the energy that plant supplies to the grid based on the input of a given quantity of fuel, because some of that fuel and/or energy produced has to be cycled in to power the CCS technology. The resulting reduction in production, known as the energy penalty or parasitic load, is an effective derating of the plant. Polk is a 220 MW unit that already runs at a low capacity factor. It is thus the type of facility that is the least well-suited to CCS.

ii. TECO could incur substantial costs to comply with new federal regulations at Polk if it operates the plant on petcoke or coal

Q Do the new greenhouse gas rules that were recently finalized under Section 111 of the Clean Air Act impact TECO's ability to burn petcoke at Polk?

A Yes. My understanding is that the final Section 111(d) rule requires plants that run past 2032 and retire before 2039 to co-fire with at least 40 percent gas in order to achieve a 16 percent reduced greenhouse gas emission rate. Given Polk 1's stated retirement date of September 2036, if TECO wanted to operate the plant on petcoke or coal, it would have to at least achieve an emissions rate based on 40 percent co-firing with fossil gas to meet the U.S. Environmental Protection Agency ("EPA")'s greenhouse gas emissions standards beginning in 2030.[40] This means that if TECO converted the plant back to an IGCC, it would have to co-fire with fossil gas at least 40 percent of the time.

[40] U.S. Environmental Protection Agency. "Final Carbon Pollution Standards to Reduce Greenhouse Gas Emissions from Power Plants," April 25, 2025. Available at https://www.epa.gov/system/files/documents/2024-04/cps-presentation-final-rule-4-24-2024.pdf.

Q Does the new Section 111(d) rule impact TECO's ability to use coal or petcoke as a hedge against gas prices?

A Yes. TECO stated that it wants to retain the ability to operate Polk 1 on petcoke, or coal blended with petcoke, to provide fuel diversity benefits. But the gas co-firing requirement means that Polk cannot insulate TECO customers from gas price volatility by simply switching to petcoke or coal. In the event that gas prices rise or become volatile again, TECO cannot just switch to petcoke or coal—it still has to meet the 40 percent co-firing requirement. And customers would have to pay high gas prices to continue operating the plant. Any gas supply shortages would similarly impact the Company's ability to rely on Polk 1, as TECO would not be able to comply with the Section 111(d) rule without combusting gas.

It is also unclear how TECO would operate the plant on petcoke and achieve the low level of emissions required to comply with the Section 111(d) rule. Petcoke has higher greenhouse gas emissions than coal[41] and would require an even higher percentage of gas co-firing to comply with this rule.

Q What does this say about Polk 1's utility as a reliability resource?

A Because Polk 1 would be required to co-fire any coal or petcoke with a significant quantity of gas, TECO cannot use Polk 1's IGCC capacity to meet reliability needs if it faces issues with its gas supply.[42]

[41] U.S. Environmental Protection Agency. "Emission Factors for Greenhouse Gas Inventories." 2023. Available at https://www.epa.gov/system/files/documents/2023-03/ghg_emission_factors_hub.pdf.

[42] *See* TECO response to SC IRR 12 (a) ("Big Bend 4 has been operated on coal when economic, for environmental needs, for logistical needs, and for natural gas supply and delivery limitations.") (Exhibit DG-2).

Q Do any of the other newly finalized environmental regulations for effluent limitations, mercury air toxins, and nitrogen oxide emissions impact TECO's cost or ability to burn petcoke or coal at Polk 1?

A Likely yes. The recently finalized 2024 Effluent Limitation Guidelines ("ELG") rule strengthens the discharge standards for three types of wastewaters produced by coal-fired units: flue gas desulfurization wastewater, bottom ash transport water, and combustion residual leachate. TECO states that it anticipates no additional compliance costs[43] because the ELG rule regulates surface water discharges, and the Polk plant discharges wastewater into a deep injection well. But the EPA has estimated that to meet these new standards and operate Polk's IG components past 2028, TECO will have to upgrade its system to comply with zero-discharge combustion residual leachate requirements at an estimated \$10,437,244 in capital costs and \$348,870 in annual O&M costs.[44] And TECO has not presented any analysis on how EPA's cost estimates will be mitigated by deep wastewater injection. Nor has it analyzed future O&M costs associated with deep wastewater injection or deep well leakage risks and potential costs.

Given these constraints and compliance costs stemming from these now-finalized federal environmental regulations, there is no reason why TECO should continue to maintain the petcoke and coal infrastructure (i.e., IG components) at the plant.

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[43] Exhibit DG-2. TECO response to SC IRR 16 (b).

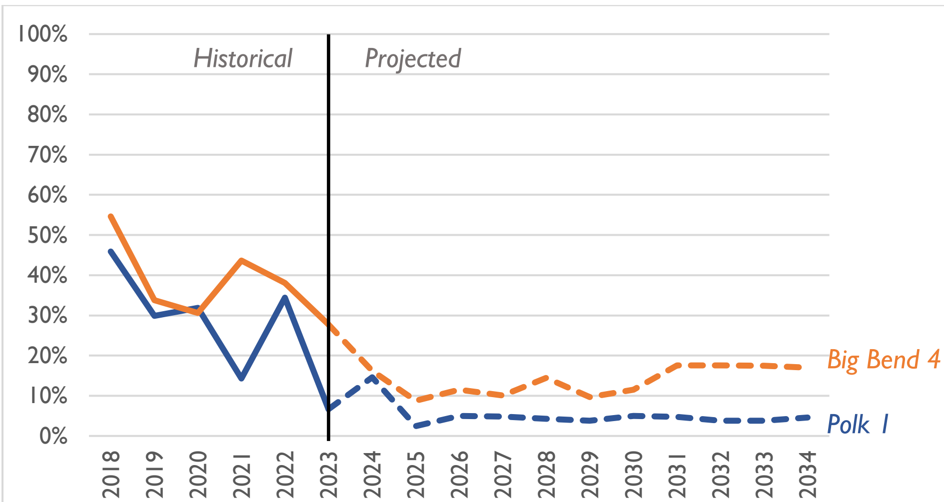
[44] Exhibit DG-9. EPA Memorandum, Steam Electric Rulemaking Record – EPA-HQ-OW-2009-0819. Unit-Level Costs and Loadings Estimates for the 2024 Final Rule (DCN SE11756A1), April 22, 2024; Exhibit DG-10. EPA Memorandum, Steam Electric Rulemaking Record – EPA-HQ-OW-2009-0819. Generating Unit-Level Costs and Loadings Estimates by Regulatory Option for the 2024 Final Rule (DCN SE11756), April 22, 2024.

iii. <u>Polk has been relatively unreliable in recent years</u>

Q Please summarize Polk 1's recent historical and projected utilization.

A As shown in Figure 5 below, the capacity factors at Polk 1 over the past five years have ranged from just above 40 percent in 2019 down to around 7 percent in 2023.[45] Over the next few years, TECO projects the unit's utilization will not exceed 5 percent, which is a significant drop below historical levels. This is not surprising if TECO plans to operate it as a peaking plant.

Figure 5. Utilization of Polk 1 and Big Bend 4



Source: TECO response to SCIRR 1-8 (e), Attachment BS (28921) 2018 - 2023 GFP and TECO response to SC IRR 1-9 (d), Attachment (BS 28927) Sierra Club 1st Set IRR Q9 .

Q How reliable has Polk 1 been in recent years?

A Polk 1 has been relatively unreliable in the past five years, with a forced outage rate ranging from a low of 7.5 percent to a high of 67 percent (Table 3). This is substantially higher than the national average for fossil plants. According to the

[45] Exhibit DG-2. TECO Response to Sierra Club IRR 8 (e).

North American Electric Reliability Corporation ("NERC")'s 2023 State of Reliability Technical Assessment, the weighted equivalent forced outage rate for all conventional generators in 2022 was 8.5 percent.[46] This represented the highest level of unavailability since NERC started tracking it in 2013—and TECO still exceeded that level in three of the past five years. The data[47] TECO provided on individual outages showed a substantial number of prolonged, unplanned outages.

Table 3. Polk 1 net equivalent forced outage rate (NEFOR)

	2019	2020	2021	2022	2023
Polk 1	8.54%	27.35%	67.40%	30.11%	7.52%

Source: TECO response to SC IRR 8, Attachment (BS 28923) 2019 - 2023 Factor and Rates.

Q Describe the unit's financial performance in recent historical years.

A As discussed above, TECO has operated Polk 1 exclusively on gas for the past five years. The unit's performance has been marginal even on gas, with unit costs exceeding market value for two of the past five years. If TECO operated the plant on petcoke or coal instead, I expect its performance would have been much worse as coal and petcoke costs have been substantially higher than gas costs.

[46] Exhibit DG-11. NERC, 2023 State of Reliability Technical Assessment, June 2023, at 3.

[47] TECO response to SC IRR 11, Attachment (BS 28931) 2018 - 2023 Outage Listing.

<u>iv. TECO has not provided analysis demonstrating that it is most economic to convert Polk 1 to operate as a CT relative to alternatives, including retirement and replacement with clean energy resources</u>

Q How is Polk 1 projected to perform going forward?

A At a high level, the Company believes that converting the unit to a CT will offer operational benefits relative to its current configuration. Specifically, TECO claims the unit will have:

- Lower operating costs, less maintenance cycles, and improved reliability.[48]
- More flexibility, faster start-up, ramp rates, and lower turndowns.[49]
- Improved heat rate.[50]

But based on my analysis, I find that the unit is expected to be only marginally economic in most years by operating as a simple-cycle CT. And when I factor in the up-front conversion cost of around $80 million, I find that the unit is expected to have a negative net present value revenue requirement ("NPVRR") of around $30.5 million ($2023).[51] This is concerning because it means that ratepayers will not only be paying down the existing undepreciated plant balance through rates,

[48] Direct Testimony of Aldazabal at 46.
[49] *Id.*
[50] *Id.*
[51] Calculated based on the following data sources: Fuel costs from TECO response to SC IRR 8 d-g, Attachment (BS 28921) 2018 - 2023 GFP (Exhibit DG-7); energy revenues calculated using TECO response to SC IRR 30 (a) and (b); capacity value calculated from bilateral energy and capacity contracts SC Confidential ROG 1-25 (a-c); Capex from TECO response to SC IRR 8 (n), Attachment (BS 28920) 2018 - 2023 Capital SC IRR8n; O&M estimated based on projected VOM and FOM provided by TECO in response to SC IRR 9, Attachment (BS 28927) Sierra Club 1st Set IRR Q9.

but they will also be incurring substantial additional costs at the unit in excess of the unit's market value.

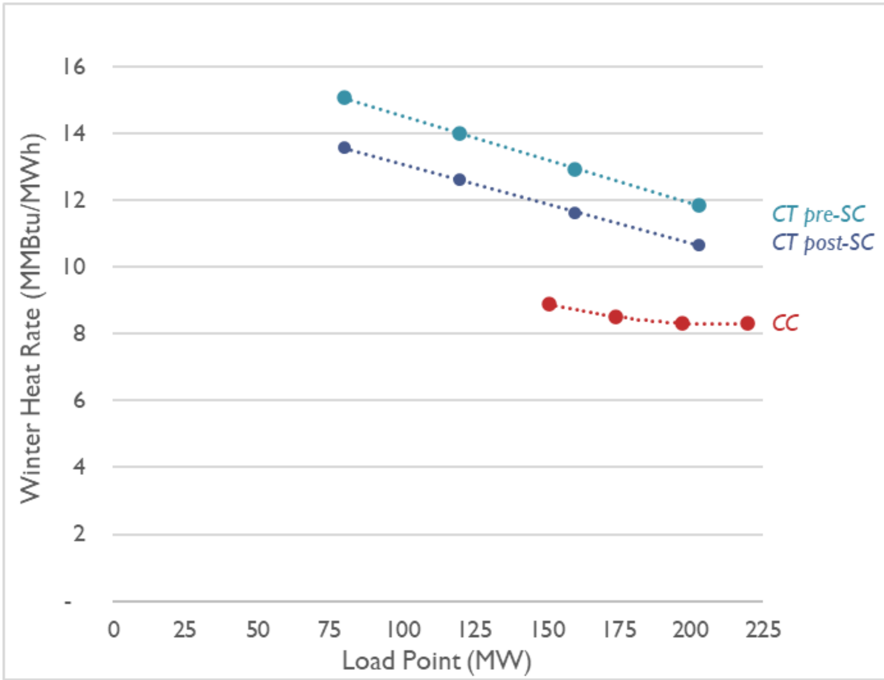
Q How will the conversion to a CT affect the efficiency of Polk 1?

A In his direct testimony, Company Witness Aldazabal lists an improved heat rate as one of the benefits of the conversion project, but the Company's data only partially supports this claim. Witness Aldazabal's statement is misleading—while the Polk 1 Flexibility Project will increase the efficiency of the CT component of Polk 1, it will decrease the efficiency of the unit as a whole.

Heat rate measures the amount of fuel a unit consumes to produce one unit of electricity, so lower heat rates indicate more efficient operation. All else being equal, CC units are more efficient than CT units, because CC units make use of the waste heat from one or more CTs to complete a second stage of electricity generation in an ST. This holds true at Polk 1, which currently operates as a CC unit. TECO projects that the average heat rate after conversion to a simple-cycle CT will be 10,653 Btu/kWh, compared to 8,770 Btu/kWh under the status quo.[52] Detailed data from the Company on the heat rate of the unit shows that across all load levels in both the summer and winter, the CT component of Polk 1 will have an improved heat rate post-conversion, but the heat rate of the CT alone will still be worse than the heat rate of the CC unit as a whole (Figure 6 and Figure 7).

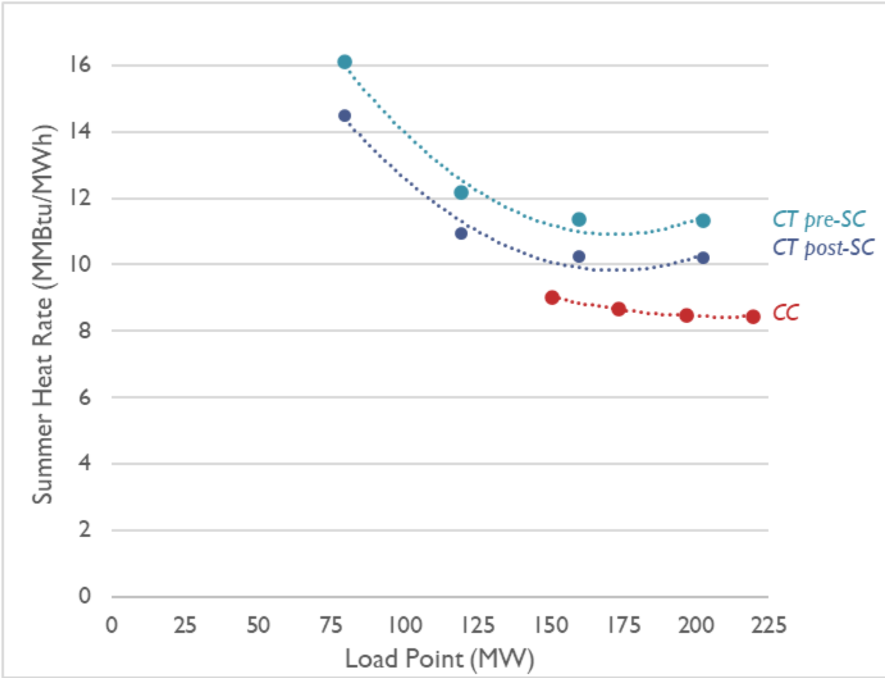
[52] Exhibit DG-3. TECO response to SC IRR 89 (j).

Figure 6. Polk 1 winter heat rate



Source: TECO Response to SC POD 8, (BS 28863) Sierra Club 1st Set Quadratic Heat Rate Formula POD Q8.xlsx. CT is combustion turbine, SC is simple-cycle conversion, and CC is combined-cycle.

Figure 7. Polk 1 summer heat rate



Source: TECO Response to SC POD 8, (BS 28863) Sierra Club 1st Set Quadratic Heat Rate Formula POD Q8.xlsx. CT is combustion turbine, SC is simple-cycle conversion, and CC is combined-cycle.

Q What analysis has TECO provided to justify its claims that the Polk Flexibility Project is in the best interest of ratepayers?

A TECO evaluated the costs and benefits of converting the unit to a CT relative to the current configuration and found that the conversion would provide $40 million in fuel benefits and a cumulative present value revenue requirement benefit of $166.9 million.[53] The Company did not consider other options, including retiring Polk 1 and replacing any needed capacity with alternatives. This is concerning because the unit has been only marginally economic in recent years and is projected to incur a net cost to ratepayers going forward. So even if the

[53] Direct Testimony of Aldazabal at 46.

conversion would provide benefits relative to the status quo, that doesn't mean that it would provide net benefits to ratepayers relative to the alternatives of early retirement or early retirement and replacement. TECO has provided no analysis evaluating alternatives or demonstrating that it is in the best interest of ratepayers to continue relying on Polk 1. The most recent retirement analysis that TECO conducted for Polk 1 was completed in the fall of 2022, before the environmental regulations described above went into effect. This analysis was done with the production cost model and evaluated a 2028 retirement date for Polk.[54]

Q Do TECO's customers need the capacity or energy from Polk 1, or otherwise benefit from having Polk 1 online?

A No. TECO repeatedly cites fuel diversity as a benefit of Polk 1 in attempting to justify maintaining the IG system at Polk. But as discussed above, fuel diversity does not justify maintaining an uneconomic asset, especially given the ongoing costs TECO will incur to maintain all the equipment at Polk 1. This is especially apparent when considering Polk's firm capacity is 2-3 percent of TECO's total firm winter capacity, and an even smaller percentage of its firm summer capacity. Even if Polk was operating at above its 5 percent capacity factor, it would still do very little to hedge against gas fuel price or supply risks, which would affect the majority of its generation fleet.

Retirement of the IG, as well as the ST and HRSG, would provide TECO with an easy opportunity to avoid unnecessary fixed operating costs and capital expenditures at this plant, in addition to avoiding the steep environmental compliance costs discussed above.

[54] Exhibit DG-2. TECO response to SC IRR 4.

Q Does IGCC have a proven track record in the U.S. power sector that would justify preserving the gasifier block at Polk 1?

A No. There are only three operational coal gasification plants in the entire U.S. power sector.[55] TECO noted that Polk 1 "is a one-of-a-kind installation because it is supplied fuel via the coal gasification process."[56] One reason the Company proposed the Polk 1 Flexibility Project is that GE, the Original Equipment Manufacturer ("OEM") of the turbine, no longer supports the turbine's combustion system.[57] Because of its bespoke design, maintaining the IGCC equipment at Polk will likely continue to be more costly and difficult than it would be for standardized generators types, where parts are still in circulation. Furthermore, it is telling that utilities across the country are constructing renewable energy to lower their energy costs, while only one coal gasification electricity generating plant has been successfully constructed in the United States since 2000.[58] This further underscores that generating syngas at Polk is unlikely to become economic in the future, and TECO—and its ratepayers—would be better off retiring the gasification equipment and focusing instead on adding clean energy to its system to replace Polk's relatively modest output.

Q What do you recommend regarding Polk 1?

A I recommend that TECO retires Polk 1—and at the very least, the IG technology, followed by the HRSG and ST technology—as soon as possible. The Company has not relied on Polk 1's ability to fuel switch, even when gas prices spiked in

[55] These are Polk, Edwardsport in Indiana, and Wabash River in Indiana. The gasification equipment at a fourth plant, Kemper, was demolished in 2021 and the unit now runs on gas only.

[56] Direct testimony of Aldazabal at 45.

[57] *Id*.

[58] Exhibit DG-13. Schlissel, D. 2017. *Using Coal Gasification to Generate Electricity: A Multibillion-Dollar Failure*. Institute for Energy Economics and Financial Analysis.

recent years, and it has provided no legitimate justification for continuing to maintain the IG technology. Further, I recommend that the Commission not allow the CT conversion until the Company produces an analysis demonstrating that converting the unit to a CT is the lowest-cost option relative to retirement and replacement with alternatives, including clean energy resources. If the conversion is approved, TECO should be required to immediately retire the ST and HRSG equipment that will not be used to operate the unit as a simple-cycle CT—in addition to retiring the IG technology, which I recommend as a cost-effective measure across all scenarios.

5. TECO SEEKS TO RETAIN THE ABILITY TO OPERATE BIG BEND 4 ON COAL DESPITE THE UNIT PERFORMING POORLY IN RECENT YEARS

i. TECO has been operating Big Bend 4 on both coal and gas in recent years, and the unit has seen declining utilization and was uneconomic when it was operated

Q How has TECO been operating Big Bend 4 in recent years?

A TECO has been operating this unit on both gas and coal (Table 4). In 2023, Big Bend 4 ran with a capacity factor of 21 percent on coal and 7 percent on gas.[59] In the first quarter of 2024 (through April), the unit ran with a 3 percent capacity factor on coal and 8 percent on gas.[60] Over the past five years, TECO operated the plant on coal the majority of the time—only in 2023 did it approach a 50/50 split,

[59] Exhibit DG-2. TECO response to SC IRR 46 (a).
[60] *Id*.

as measured by service hours.[61] On a net generation basis, gas still only accounted for around a quarter of Big Bend 4's output in 2023.

Table 4. Big Bend 4 plant statistics operating on coal and gas

	2019	2020	2021	2022	2023
Net Capability (MW)					
Coal	438	392	425	425	425
Gas	188	170	157	418	413
Service Hours (hrs)					
Coal	3,973	3,337	4,850	5,575	3,404
Gas	681	1,278	2,367	1,355	3,331
Net Generation (MWh)					
Coal	1,214,307	909,110	1,357,954	1,336,581	769,413
Gas	83,516	143,651	274,144	83,267	263,553
Annual Capacity factor (%)					
Coal	32%	26%	36%	36%	21%
Gas	5%	10%	20%	2%	7%

Source: TECO response to SC IRR 8, Attachment (BS28921) 2018-2023 GFP.xlsx.

TECO reports that it is departing from this historical practice, and going forward, "the company plans to operate Big Bend 4 mostly on natural gas and expects to burn minimal amounts of coal to keep the solid fuel equipment viable."[62] In other words, TECO doesn't anticipate that burning coal will be economic, but it will still do so—at the expense of ratepayers—because it wants to maintain the solid fuel equipment. Burning coal at Big Bend 4 will be uneconomic because the unit's fuel costs are lower on gas, as well as its expected variable O&M costs ("VOM")—which are less than half the cost to operate on coal.[63] Burning coal

[61] Exhibit DG-7. TECO response to SC IRR 8, Attachment (BS 28921) 2018 - 2023 GFP.

[62] Exhibit DG-2. TECO response to SC IRR 46 (a).

[63] Exhibit DG-2. TECO response to SC IRR 46 (c).

will not even be necessary to maintain a firm fuel supply given that the Company has indicated that it has and will continue to have firm gas supply contracts.

Q How has the unit's operational performance been recently?

A As shown in Table 5, Big Bend 4 experienced a high outage rate in recent years, with a forced outage rate of between 8.7 percent and 31.6 percent over the past five years. TECO ratepayers will continue to be exposed to these outage risks as long as the Company continues to rely on the plant.

Table 5. Big Bend 4 net equivalent forced outage rate (NEFOR)

	2019	2020	2021	2022	2023
Big Bend Unit 4	28.09%	32.04%	8.71%	31.61%	18.08%

Source: TECO response to SC IRR 8, Attachment (BS 28923) 2019 – 2023 Factor and Rates.

Q Please summarize the recent historical and projected utilization of Big Bend 4.

A As shown in Figure 5, Big Bend's utilization has ranged between 28 and 44 percent over the past five years.[64] Going forward, TECO projects the plant will operate at between an 8.8 percent and a 17.6 percent capacity factor over the next decade.[65] This is a very low utilization rate for a baseload plant such as Big Bend 4.

Q Describe the unit's financial performance in recent historical years.

A As shown in Table 6, Big Bend has been uneconomic to operate since 2019 and shows net negative value in three of the past five years (based on fuel costs, O&M, capital expenditures, energy and capacity value). The years 2021 and 2022

[64] Exhibit DG-7. TECO response to SC IRR 8, Attachment (BS 28921) 2018 - 2023 GFP.
[65] TECO response to SC IRR 9, Attachment (BS 28927) Sierra Club 1st Set IRR Q9.

were exceptions when Big Bend 4 showed positive net value. However, these results were based on energy and gas market prices prompted by COVID and the war in Ukraine, which are rare and not expected to continue going forward.

Table 6. Historical net value of Big Bend 4 ($2023 M) (2019-2023)

	2019	2020	2021	2022	2023
Big Bend 4	($38.9)	($63.5)	$21.4	$82.5	($29.1)

Source: Fuel costs from TECO response to SC IRR 8 d-g, Attachment (BS 28921) 2018 – 2023 GFP; energy revenues calculated using TECO response to SC IRR 30 (a) and (b); capacity value calculated from bilateral energy and capacity contracts SC Confidential ROG 1-25 (a-c); Capex from TECO response to SC IRR 8 (n), Attachment (BS 28920)2018 – 2023 Capital SC IRR8n; O&M from FERC Form 1 and TECO response to SC IRR 9.

Q Explain the methodology you used to develop this historical analysis.

A I relied on Company data from TECO and public data to calculate the cost and revenues TECO incurred at Polk 1 between 2019 and 2023. I summed energy and capacity value to find total value. Because TECO is not located in an organized market, I relied on bilateral capacity contracts[66] that the Company provided for the past five years to calculate capacity value. I calculated energy value based on the Company's off-system energy sales and purchases[67] from 2019 to 2023 for each year, which were also provided by the Company.

I added the fuel costs, non-fuel O&M costs, and sustaining capital expenditures to get total unit costs. I used fuel costs[68] and capital expenditures[69] provided by the Company. For historical O&M costs (fixed and variable combined), TECO

[66] TECO response to Confidential SC IRR 25, Attachments ROG_1_25a-CONF_bates, ROG_1_25b_purchases-CONF_bates, ROG_1_25b-sales-CONF_bates, ROG_1_25c-CONF_bates.
[67] Exhibit DG-2. TECO response to SC IRR 30 (a) and (b).
[68] Exhibit DG-7. TECO response to SC IRR 8 (d-g), Attachment (BS 28921) 2018 - 2023 GFP.
[69] TECO response to SC IRR 8 (n), Attachment (BS 28920) 2018 - 2023 Capital SC IRR8n.

asserted it does not have historical fixed O&M ("FOM") and VOM data, so I relied on the FERC Form 1[70] for FOM and used TECO's projected VOM costs for the unit as a proxy for its historical costs.[71] I netted the unit costs and value to find the unit's historical net value (or cost) for each year.

Q Does this analysis reflect system costs as they are allocated to ratepayers through the Company's revenue requirement?

A No. This analysis is not intended to reflect the way costs are passed on to ratepayers over the lifespan of energy assets—but rather to provide a comparison of real-time expenses and revenues. Revenue requirements inherently require assumptions around the lifetime of assets/resources. Additionally, a substantial portion of resource costs are deferred until the future through capital and regulatory asset treatment. Therefore, poor near-term unit economics can be diluted or obscured by spreading out the losses over a longer period of time.

My analysis, on the other hand, is intended to provide a clear snapshot of how input revenues match output costs. It may be reasonable for expenses to exceed revenues in a single year (for example, when a large capital investment is made). But over a period of multiple years, expenses should not regularly exceed revenues. If they do, that is a strong indication that the unit is not operating economically.

[70] FERC Form 1.
[71] TECO response to SC IRR 9, Attachment (BS 29827) Sierra Club 1st Set IRR Q9.xlsx.

ii. Based on TECO's data, Big Bend 4 is projected to continue to be uneconomic moving forward, especially when operated on coal

Q How is Big Bend 4 projected to perform going forward?

A Going forward, TECO's own data suggests that Big Bend 4 will be very uneconomic to operate, and that the unit's costs will exceed its value from 2024 to 2033, as shown in Table 7 below. This is due in part to the low capacity factor at which the unit is projected to operate, as seen in Figure 5, coupled with the relatively high costs required to maintain a baseload plant. As discussed above, the unit shows record-low utilization and is projected to operate at capacity factors below 20 percent from 2024 to 2034. The potentially large capital investments required to meet various recently finalized federal environmental regulations, including the Section 111(d) standards for greenhouse gases and the ELG rule, will make the plant even more costly and uneconomic.

Table 7: Projected net value of Big Bend 4 ($2023 M) (2024-2033)

Year	$2023 M
2024	($6.1)
2025	($1.9)
2026	($6.6)
2027	($10.5)
2028	($5.6)
2029	$2.9
2030	($4.2)
2031	($12.7)
2032	($21.1)
2033	($10.0)

Source: Fuel and VOM costs from TECO response to SC IRR 9, Attachment (BS 28927) Sierra Club 1st Set IRR Q9; FOM based on historical FOM from FERC form 1 net of projected VOM from TECO response to SC IRR 8 (which is use as a proxy for projected VOM); capex from TECO response to SC IRR 9, Attachment (BS 38292) 2024 – 2028 Capital SC IRR9m; energy value from

TECO Confidential response to SC 1-30(c-d), various attachments; capacity value from TECO Confidential response to SC 1-25b, various attachments.

Q How did you calculate the projected value of Big Bend 4?

A As with the historical analysis presented above, I relied on Company projections for unit costs over the next ten years, supplemented by public data where no Company data was provided. I summed energy and capacity value to find total value. I relied on the same bilateral capacity contracts[72] that the Company provided for the past five years to calculate capacity value. I calculated energy value based on the Company's projection of off-system energy sales and purchases[73] from 2024 to 2034.

I added the fuel costs, non-fuel O&M costs, and sustaining capital expenditures to get total unit costs. I used fuel costs,[74] projected VOM costs,[75] and capital expenditures[76] provided by the Company. TECO did not provide FOM data, either projected or historical, for Big Bend 4, so I relied on the FERC Form 1[77] historical data for fixed O&M for the entire Big Bend plant and scaled it by MW to estimate the portion for just Unit 4. Because FERC Form 1 costs represent both FOM and VOM, I netted out the historical VOM to isolate just the FOM.

I then netted the unit costs and value to find the unit's historical net value (or cost) for each year.

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[72] TECO response to Confidential SC IRR 25, Attachments ROG_1_25a-CONF_bates, ROG_1_25b_purchases-CONF_bates, ROG_1_25b-sales-CONF_bates, ROG_1_25c-CONF_bates.

[73] TECO response to Confidential SC IRR 30, Attachments ROG_1_30c-CONF_bates, and ROG_1_30d-CONF_bates.

[74] TECO response to SC IRR 9, Attachment (BS 28927) Sierra Club 1st Set IRR Q9.

[75] *Id*.

[76] TECO response to SC IRR 9, Attachment (BS 38292) 2024 - 2028 Capital SC IRR9m.

[77] FERC Form 1.

Q What analysis has the Company performed on the economics of continuing to operate Big Bend 4 on coal through 2040 to justify including its ongoing O&M and capital expenditures in rates?

A Notably, the Company has not provided any analysis showing the continued reliance on Big Bend 4 is in the best interests of ratepayers. It argues that no analysis is needed because "that asset has numerous years of remaining useful life."[78] Despite projecting much higher dispatch costs for coal compared to gas,[79] TECO has not analyzed the feasibility or the cost of operating Big Bend 4 entirely on gas, claiming that "it is premature to incur significant costs to develop cost estimates and system impacts associated with repowering a unit with at least fifteen years of life left on it."[80]

This is a faulty line of reasoning on TECO's part. The Company should not make retirement decisions based on sunk costs, but rather based on the unit economics and the forward-going costs required to operate the unit. Units like Big Bend 4 that consistently yield negative net revenues should be retired and replaced with alternate sources of generation that can save ratepayers money immediately by incurring lower marginal costs than a coal plant. And there are alternative ways to address the undepreciated plant balance at Big Bend 4, such as through a regulatory asset or by using funding available under the EIR. These options will cost ratepayers substantially less than continuing to operate the plant, despite the availability of cheaper alternatives.

[78] Exhibit DG-2. TECO response to SC IRR 1.
[79] Exhibit DG-2. TECO response to SC IRR 46 (c).
[80] Exhibit DG-2. TECO response to SC IRR 40.

Q What fixed costs are avoidable at Big Bend 4 with an earlier retirement?

A Retirement would allow TECO to avoid unnecessary fixed operating costs and capital expenditures at this plant, including environmental compliance costs. In 2022, TECO incurred $17 million in sustaining capital costs at Big Bend 4, and the Company included a projected $7.5 million in sustaining capital costs for the unit in its test year spending.[81] TECO's own projections for Big Bend 4's capital expenditures over the next five years are low, working out to about $13 million in capex per year.[82] This is substantially lower than TECO's average Big Bend capex spending over the past five years, which was around $30 million per year.[83] TECO did not provide forecasted fixed O&M costs for Big Bend 4, stating in discovery that it does not have this data.[84] This is concerning, given that a forecast of forward-going costs is necessary to evaluate the economics of operating a plant. If TECO does not have a forecast of future O&M costs for a unit, then it can't be evaluating the forward-going economics of the unit and understanding what costs are avoidable with early retirement.

iii. TECO could incur substantial costs to comply with new federal regulations at Big Bend 4 if it operates the plant on coal

Q Do any new federal greenhouse gas emissions rules impact the cost of TECO continuing to operate on coal at Big Bend Unit 4?

A Yes. My understanding is that under the newly finalized greenhouse gas standards under Section 111 of the *Clean Air Act*, plants retiring after January 1, 2039 will

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[81] Exhibit DG-2. TECO response to SC IRR 5.
[82] TECO response to SC IRR 9 (m), attachment (BS 38292) 2024 - 2028 Capital SC IRR9m.
[83] TECO response to SC IRR 8 (m), attachment (BS 28920) 2018 - 2023 Capital SC IRR8n.
[84] Exhibit DG-2. TECO response to SC IRR 9 (i).

have to meet a carbon emissions standard based on a standard of 90 percent capture of carbon dioxide by January 1, 2032. That means TECO's options at Big Bend Unit 4 are to:

- Maintain the stated 2040 retirement date and install CCS by January 1, 2032, achieving an 88.4 percent reduction in the unit's gross carbon dioxide emissions rate relative to its unit-specific baseline;
- Move up the retirement date to January 1, 2039, or earlier, and meet a medium-term standard based on 40 percent co-firing on natural gas by volume (equivalent to a 16 percent reduction in the unit's gross baseline carbon dioxide emission rate) starting January 1, 2030;
- Retire the unit before January 1, 2032, and avoid any compliance costs or requirements under this particular rule. However, operating Big Bend 4 past 2027 may still result in environmental compliance costs for TECO related to the MATs and ELG rules.

TECO itself noted that Big Bend 4 could comply with the Section 111 rule by retiring 1–2 years earlier than planned (prior to January 1, 2039, rather than in 2040) and that no major enhancements to the unit would be necessary under this approach.[85] But this would require that the Company co-fired on gas more than it has historically (or at least any time during the past five years) starting in 2030.

Q What are the estimated compliance costs for Big Bend 4 to comply with EPA's ELG Rule?

A The 2024 ELG rule strengthens the discharge standards for three types of wastewater produced by coal-fired units: flue gas desulfurization wastewater

[85] Exhibit DG-3. TECO response to SC IRR 88.

("FGD"), bottom ash transport water, and combustion residual leachate. EPA projects that Big Bend 4 is likely to have to invest in upgrades to meet new zero discharge FGD standards. They project these upgrades will cost $129 million in capital costs alone, with annual O&M costs of around $9 million.[86] Alarmingly, these costs remain the same across three different compliance options modeled by EPA in its technical memorandum attached to the final ELG rule.

TECO indicated that Big Bend 4 is already in compliance with the ELG rule, which regulates discharge to surface water, since it disposes wastewater into a deep injection well.[87] But this contradicts EPA's projections that ELG compliance would cost TECO $129 million at Big Bend 4.[88] Notably, TECO has not provided an analysis of how its deep injection wells at Big Bend will mitigate EPA's projected compliance costs for discharging FGD, nor has it disputed FGD discharge levels published by EPA.

Q What are the estimated compliance costs for Big Bend 4 to comply with EPA's Mercury and Air Toxics Standards ("MATS") regulations?

A TECO acknowledged that the MATS rule is applicable to Big Bend 4, but indicated that it expects no material additional compliance costs with the final MATS standards. Yet, in the unit-level regulatory impact analysis submitted

[86] Exhibit DG-9. EPA Memorandum, Steam Electric Rulemaking Record – EPA-HQ-OW-2009-0819. Unit-Level Costs and Loadings Estimates for the 2024 Final Rule (DCN SE11756A1), April 22, 2024; Exhibit DG-10. EPA Memorandum, Steam Electric Rulemaking Record – EPA-HQ-OW-2009-0819. Generating Unit-Level Costs and Loadings Estimates by Regulatory Option for the 2024 Final Rule (DCN SE11756), April 22, 2024.

[87] Exhibit DG-2. TECO response to SC IRR 14.

[88] Exhibit DG-9. EPA Memorandum, Steam Electric Rulemaking Record – EPA-HQ-OW-2009-0819. Unit-Level Costs and Loadings Estimates for the 2024 Final Rule (DCN SE11756A1), April 22, 2024.

along with the finalized 2024 MATS rule.[89] EPA lists Big Bend 4 in its catalog of impacted units and also identifies Big Bend's lowest achievable filterable particulate matter ("fPM") rate based on historical data as 0.00953 lb/MMBTU, which is just below the 0.01 lb/MMBTU threshold adopted in the final rule. If Big Bend 4's fPM rates push up above the 0.01 threshold, it will not be in compliance with the MATS rule, and the Company would have to install pollution controls by 2027 to comply. Operating Big Bend solely on gas would avoid any possibility of Big Bend 4 falling out of compliance with the MATS rule.

Q **What other options does TECO have for reducing the impact of operations at Big Bend 4?**

A TECO's reserve margin is substantially lower in the winter than in the summer. That means that the Company's resource needs are concentrated in the winter. Another option is to switch Big Bend 4 to seasonal operation, and only rely on it during the winter peak months. This is something that has been done by Xcel Energy in Minnesota for its coal plants. Utilities in Indiana and Missouri have also recently expressed interest in this option. In this event, although Big Bend 4's O&M costs and pollution would decrease in tandem with its capacity factor, it would still face the high environmental compliance costs described above, as those remain unaffected by seasonal operations.

Another option is to end the use of coal at the plant immediately and switch it to only operate on gas, in advance of an early retirement. Given that the Company has indicated that operation on gas is currently less costly than operation on coal,

[89] Exhibit DG-14. U.S. EPA. 2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category (2024 Technical Memo), Attachment 1.

and that it is only burning coal to keep the solid fuel equipment viable,[90] such a switch is in line with the unit's economics.

6. TECO SHOULD EVALUATE RETIREMENT AND REPLACEMENT OPTIONS FOR ITS COAL PLANTS AND APPLY FOR EIR FUNDING TO FACILITATE THE COST-EFFECTIVE EARLIER RETIREMENT OF BIG BEND 4

i. TECO should evaluate replacement resources for its coal units at Polk and Big Bend

Q If TECO has sufficient capacity to meet its current summer and winter reserve margins, does that mean it should not consider any new clean energy resources?

A No. Need is not just about having enough physical capacity on a system, but also the economics of operating existing generation relative to alternatives. TECO can and should regularly evaluate—as part of its resource planning exercises—whether it is more economical to get the energy and capacity it needs from its existing fossil resources, or to retire and replace them with clean energy alternatives. Prices of renewable energy resources have fallen substantially in recent years. Many utilities are selecting a combination of low-variable-cost renewables and flexible, dispatchable capacity as their preferred least-cost resource plan.

TECO should study the economics of maintaining an adequate, but not excessive, capacity position to serve its customers. Maintaining an appropriate capacity position for customers may require the sale, transfer, or retirement of some

[90] Exhibit DG-2. TECO response to SC IRR 46(a).

C32-3171

existing resources, as well as the procurement of additional resources that are more economical solutions to meeting current system needs. To support its study of resource economics, TECO should be proactive and test the market with requests for proposals to evaluate replacement resource options so it can procure lower-cost clean energy to replace its uneconomic coal plants.

Q What risks does TECO expose its ratepayers to through continued reliance on coal, petcoke, and gas?

A TECO's plan to continue relying heavily on gas, coal, and petcoke exposes ratepayers to fuel price volatility, to the cost of complying with future environmental regulations, and to potential grid crises from outages related to legacy fossil fuel infrastructure facing up against Tampa's hurricane season.

Q Explain the risks posed to ratepayers by fuel price volatility.

A Continued reliance on fossil gas subjects ratepayers to gas price volatility. TECO's portfolio got 82 percent of its generation from gas in 2023 and only 8 percent from solar PV.[91]

This level of reliance on gas is risky because when the market is constrained and prices spike, those costs are passed directly to ratepayers. For example, when DTE Electric Company in Michigan filed its 2022 Fuel Reconciliation Docket, it noted that gas spending was 74 percent higher than planned. These higher-than-expected prices resulted in large part from the Russian invasion of Ukraine, and European gas customers turning increasingly to U.S. gas. As a result, DTE is requesting to recover an additional $154 million for 2022 fuel costs alone.[92]

[91] Exhibit DG-5. 2024 TYSP, Schedule 6.2.
[92] DTE Elec. Co. 2023. Exhibit *A-7.* Mich. Pub. Serv. Comm'n Docket No. E-21051. March 31, 2023.

Absent action from the Michigan Public Service Commission, DTE and its shareholders are not impacted by these gas price spikes—these costs are entirely passed on to ratepayers. The same phenomenon could happen just as easily in Florida or elsewhere in the Southeast. TECO should take this into account in planning its future resource mix. In fact, TECO's own historical fuel data shows that it experienced high gas costs in 2022 when gas prices spiked.[93]

Q Is TECO aware of the risks posed by exposure to gas price volatility?

A Yes, TECO recognizes the riskiness of its high level of exposure to gas price volatility, and stated in its most recent TYSP that it seeks to perform integrated resource planning in a "manner that reduces reliance on natural gas and its associated price volatility risk for customers."[94] However, the Company should re-think its approach to ensuring fuel diversity. TECO cites maintaining fuel diversity as a reason to maintain the capability for Polk 1 to burn petcoke[95] and Big Bend 4 to burn coal.[96] As I explain below, reliance on coal and petcoke poses many of the same risks as gas. TECO could more effectively protect its customers by procuring clean energy capacity, including solar PV, BESS, and wind. These resources are not subject to fuel price volatility, because they use no fuel, and they are not at risk of future environmental regulation, because they do not emit greenhouse gases or toxic pollutants. Moreover, the cost declines in the price of BESS means that solar PV and wind paired with battery storage can be utilized as a dispatchable resource.

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[93] Exhibit DG-2. TECO response to SC request IRR 8.
[94] Exhibit DG-5. 2024 TYSP at 2.
[95] Exhibit DG-3. TECO response to SC IRR 89(a).
[96] Exhibit DG-2. TECO response to SC IRR 40.

Q Explain the risks posed to ratepayers from continued reliance on coal and petcoke assets.

A The coal market has seen dramatic price volatility in some parts of the United States over the past few years.[97] There have also been labor challenges both at the mines and the railroad companies that transport the coal, as coal workers demand better pay and have more options in the labor market. Additionally, as more and more coal plants across the United States retire and the demand for coal contracts declines, there will be additional pressure on the coal industry. TECO itself has announced it is not renewing its long-term coal contracts,[98] further demonstrating the trend in declining coal contracts. The combination of declining demand and labor challenges could result in consolidation among coal companies and subsequently higher coal prices.[99]

Coal use was down in 2023 and never reached more than 20 percent of power market share (through October). This steady decline is novel because market share had been around 20 percent each month between 2020 and 2022, and prior to 2020, coal had never comprised less than a 20 percent market share in any month.[100] Additionally, as I discuss next, risks from increased environmental regulation could result in higher costs and higher risks for coal usage. Higher regulatory risk impacts not just resource planning economics, but also company

[97] U.S. Energy Information Administration, "Coal Markets." Available at https://www.eia.gov/coal/markets/.

[98] Exhibit DG-3. TECO response to SC IRR 79.

[99] Exhibit DG-15. Duke Energy, "Appendix F: Coal Retirement Analysis," 2023 Carolinas Resources Plan.

[100] Exhibit DG-16. Institute for Energy Economics and Financial Analysis, "Coal Use at U.S. Power Plants Continues Downward Spiral; Full Impact on Mines to be Felt in 2024," Nov. 2, 2023.

risk profiles, which can lead to downgraded credit ratings, and that can impact access to capital.

Additionally, breakdowns of parts and a lack of continued support from manufacturers based on the old age of coal plant technology can result in sustained outages and challenges in quickly repairing units and getting them back online.

Q Explain the risks posed by future environmental regulations.

A As discussed above, EPA recently finalized rules to regulate carbon dioxide emissions from new gas plants and existing coal plants, as well as mercury and air toxics emissions (including fine particulate matter) and effluent discharge. It is likely that additional environmental regulations will be issued, particularly ones that regulate emissions from existing gas plants. These regulations would continue to make it costlier and riskier to rely on gas resources.

Q Explain the costs and risks of coal ash disposal.

A For years, TECO deposited much of its coal ash in unlined ponds. Complying with EPA's recently updated stricter coal ash storage rule, called the Coal Combustion Residuals ("CCR") rule, could result in additional costs to ratepayers to line those unlined ponds and to construct and retrofit ponds to store coal ash that is disposed of in real time.[101] Indeed, TECO has acknowledged that it may have to remediate CCR surface impoundments and CCR management units as a

[101] Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Legacy CCR Surface Impoundments, 89 Fed. Reg. 38,950 (May 8, 2024).

result of the recently finalized updated CCR rule.[102]And there is already evidence of groundwater contamination from Big Bend 4's two unlined ponds.[103] Under federal law, TECO is required to remediate that contamination and prevent any further contamination associated with its current operations. This could incur significant costs, which would be imposed on TECO ratepayers and shareholders alike.[104]

Q What replacement resource should TECO consider?

A TECO should consider a range of low-cost clean energy resources to replace its coal plants, including solar PV, BESS, wind, energy efficiency, and demand response. The Company should be testing the market regularly and procuring solar PV, BESS, and other clean energy resources to economically displace energy and capacity from existing high-cost fossil resources.

Q How much BESS and solar PV does TECO currently have on its system?

A TECO currently has 1,252 MW of solar PV on its system,[105] which accounted for 8 percent of the Company's generation mix in 2023.[106] The Company currently has no BESS on its system. Going forward, TECO does plan to add 842 MW more in planned solar PV additions between 2024 and 2028, as well as 185 MW of BESS that will come online in the same timeframe (Table 8). Further out, TECO plans to add an additional 745 MW of solar PV between 2029 and 2033.

[102] Exhibit DG-2. TECO Response to SC IRR 14.
[103] Exhibit DG-17. Earthjustice, "Toxic Coal Ash in Florida: Addressing Coal Plants' Hazardous Legacy," May 3, 2023.
[104] Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Legacy CCR Surface Impoundments, 89 Fed. Reg. 38,950 (May 8, 2024).
[105] Exhibit DG-5. 2024 TYSP at 3.
[106] *Id*. at 1.

While it's encouraging that the Company plans to add some new solar PV and BESS, it is concerning that the quantities are so low—especially for BESS. Table 8 also shows TECO's projected construction costs for these resources.

Table 8. TECO planned solar PV and battery capacity additions and construction costs

	Solar PV			Storage		
	Planned Capacity Additions (MW)	Projected Total Construction Cost ($M)	Projected cost per kW ($/kW)	Planned Capacity Additions (MW)	Projected Total Construction Cost ($M)	Projected cost per kW ($/kW)
2024	97.5	$167	$1,713	15	$19	$1,267
2025	149	$244	$1,638	100	$143	$1,430
2026	242	$419	$1,731	0	$0	
2027	149	$285	$1,913	0	$0	
2028	204	$371	$1,819	70	$142	$2,029
2029	149	*TBD*		0	*TBD*	
2030	149	*TBD*		0	*TBD*	
2031	149	*TBD*		0	*TBD*	
2032	149	*TBD*		0	*TBD*	
2033	149	*TBD*		0	*TBD*	

Source: TECO 2024 Site Plan, Schedule 8.1 and TECO response to SC IRR 91.

ii. TECO should apply for EIR funding under the IRA to finance clean energy replacement resources, and potentially also refinance undepreciated plant balances at Big Bend 4

Q What is the EIR program?

A The EIR program, established under IRA, provides the DOE's LPO with around $250 billion in loan authority that it can deploy to "retool, repower, repurpose, or replace" fossil infrastructure.[107] The loans are available at just above the federal government's cost of borrowing, with repayment periods up to 30 years—which means they offer a cheap method of financing the undepreciated capital costs of a plant. The EIR's loans are even cheaper than financing the capital costs of coal plants by treating them as a regulatory asset.[108] Per statute, utilities are required to pass through the savings enabled under the EIR to their customers.[109]

The loans are intended to additionally finance investments in replacement generation capacity, distribution upgrades, or other investments that can help enable greenhouse gas emission reductions. And while the total loan amount is capped at 80 percent of the replacement project cost, my understanding is that the funding can be used to both lower the project costs for replacement resources and address legacy asset plant balances.[110]

Q How does the EIR program provide value to ratepayers?

A There are two main ways that the EIR program can provide value to ratepayers (assuming that the utility does not use debt from the program to alter its capital structure, i.e. debt-to-equity ratio): (1) by swapping federal LPO debt for utility debt, and (2) by providing capital utilities can use to refinance existing plant balances.

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[107] Exhibit DG-18. U.S. Department of Energy, Loan Programs Office, Program Guidance for Title 17 Clean Energy Financing Program, May 19, 2023.

[108] *Id.* at 8.

[109] Id. at 28.

[110] Exhibit DG-19. C. Fong, D. Posner, and U. Veradarajan, "The Energy Infrastructure Reinvestment Program: Federal financing for an equitable, clean economy," RMI, February 16, 2024.

The first option can provide value to ratepayers if the utility itself does not have access to low-cost debt, but the benefits of using the loan in this way alone are not expected to be large. The more substantial benefits from an EIR loan are expected to stem from refinancing existing plant balances.[111] This addresses a critical barrier to retirement and can help accelerate unit retirements while reducing the economic burden on ratepayers relative to traditional financing mechanisms (and providing the utility with a level of certainty on cost recovery, which can ultimately improve its credit rating).

Q Explain the swapping of federal LPO debt for utility debt.

A LPO can provide debt to finance new clean energy resources. Here ratepayers benefit from the difference between the debt rate available from the LPO and the debt to which the Company would otherwise have access. The benefits of this option would have to outweigh the program's transaction costs, and may not, in themselves, be sufficient to warrant using this program.[112]

Q Explain the EIR provision for refinancing remaining plant balances.

A EIR loans provide capital that can be used to refinance the undepreciated balance of legacy fossil assets. While refinancing plant balance is not explicitly spelled out in existing guidance for the EIR program, and EIR applications cannot include funds for undepreciated plant balances, if the loan does not exceed the value of the clean energy replacement resources and the benefits are passed onto

[111] Exhibit DG-20. C. Fong, D. Posner, and U. Varadarajan, "Maximizing the value of the energy infrastructure reinvestment program for utility customers," RMI, May 24, 2024.

[112] RMI performed some calculations on the value this would provide and found that the benefits from trading LPO debt for utility debt are expected to be minimal.

ratepayers, utilities have the discretion to use the funds in this manner. Indeed, other utilities have confirmed that plant balance refinancing is allowed based on conversations with the LPO.[113]

To achieve this outcome, the plant balance would be transferred to a special purpose vehicle ("SPV"), removed from TECO's rate base (and balance sheet), and refinanced at the LPO debt rate. The Commission would have to approve a separate surcharge to repay the plant balance; and it should do so, because that would be a win-win for both the Company and ratepayers. Ratepayers would benefit because the federal LPO rate is lower than the utility's normal cost of capital, and the utility would benefit by removing a risky asset from its balance sheet. And the Commission would benefit because this would allow it to focus on approving the funding of resources that are needed to serve ratepayers. There would be a cost to create the SPV surcharge, but those costs would be outweighed by the benefits.

Q What are the benefits of using EIR financing to address undepreciated balances?

A There are multiple benefits of EIR financing, although the exact benefits accrued will vary based on the exact financing structure that a utility uses. EIR funding enables the following benefits:

- Removes the undepreciated plant balances from legacy assets from utility books. This is desirable because this is generally a low-quality, high-risk portion of a utility's rate base and is ultimately not desirable. This can

[113] *See, e.g.,* Iowa Utilities Board Docket RPU-2023-0002, Rebuttal Testimony of Christopher Boberg at 6.

improve utilities' credit ratings and result in more favorable financing terms for future projects.

- Enables the recycling of capital, which can in turn be made available to invest in new resources and projects.
- Facilitates repurposing of existing energy infrastructure, such as transmission, saving time and costs for ratepayers.
- Lowers costs for ratepayers by reducing the rate of return recovered on the undepreciated plant balance.
- Brings online new clean energy resources that can reduce costs and risks for ratepayers over the long term relative to continued reliance on fossil resources.

Q Why is it important that TECO gets started on an EIR application now?

A All projects that receive federal funding have to undergo a federal environmental review process under the National Environmental Policy Act ("NEPA"). This review process has historically been time-intensive, which is why the Biden administration recently finalized a rule to reform NEPA review process. Moreover, EIR is a rolling application and a number of utilities have already indicated their intent to apply for EIR funding.[114]

[114] Portland General Electric in Oregon, Consumers Energy in Michigan, Duke Energy in the Carolinas, and Alliant Energy in Wisconsin and Iowa.

Q **Has TECO applied for EIR funding or evaluated the potential to utilize funding from the EIR to finance replacement resources or refinance undepreciated plant balances?**

A No. TECO stated in discovery that it has not evaluated the potential use of the EIR program at any of its units,[115] nor has it communicated with DOE about the program.[116]

Q **What is your recommendation regarding TECO and EIR funding?**

A I recommend that TECO commit to locking in a retirement date for Big Bend 4 in its next rate case and submit an application for EIR financing as soon as possible, but in any event, before the program deadline in September 2026.

Q **Does this conclude your testimony?**

A Yes.

[115] Exhibit DG-2. TECO response to SC IRR 18.
[116] Exhibit DG-2. TECO response to SC IRR 19.

C32-3182

MR. SPARKS: And we would also move the Sierra Club exhibits, which are identified on the CEL as 113 through 132.

CHAIRMAN LA ROSA: Is there objection?

Seeing none, show them entered into the record.

MR. SPARKS: Thank you.

CHAIRMAN LA ROSA: Great. Thank you.

(Whereupon, Exhibit Nos. 113-132 were received into evidence.)

MR. MARSHALL: Thank you, Mr. Chairman. We are ready whenever you are.

CHAIRMAN LA ROSA: Great.

MR. MARSHALL: And the witness has not been previously sworn.

CHAIRMAN LA ROSA: Mr. Rabago, am I saying that correctly?

MR. RABAGO: I am ready.

CHAIRMAN LA ROSA: Excellent.

Please raise your right hand.

Whereupon,

KARL R. RABAGO

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

THE WITNESS: I do.

CHAIRMAN LA ROSA: Excellent. Thank you.

EXAMINATION

BY MR. MARSHALL:

Q Good morning.

A Morning.

Q Can you please state your name and business address for the record?

A Yes. My name is Karl Rabago, and I am the owner and sole employee at Rabago Energy, a consultancy based in Denver, Colorado.

Q And on whose behalf are you testifying?

A I am testifying on behalf of the League of United Latin American Citizens and Florida Rising.

Q Mr. Rabago, on June 6th, 2024, did you prepare and cause to be filed testimony and Exhibits KRR-1 through KRR-5 in this docket?

A Yes.

Q And do you have that testimony and those exhibits with you today?

A Yes.

Q Do you have any changes or corrections to your prefiled testimony or exhibits?

A Yes, I do, just a couple.

These corrections are all on page four of my direct testimony. On line 21, delete the numerals one, comma, one -- or 1.162 and insert 555.

On line 22, delete the word "billion" and insert the word "million". Also on line 22, delete "555 million", and insert the words "about two-thirds".

Q And other than those corrections, if I asked you the same questions today, would your answer be the same?

A The same, or substantially the same, yes.

MR. MARSHALL: Mr. Chairman, at this point, I would like to have Mr. Rabago's prefiled direct testimony entered into the record as though read.

CHAIRMAN LA ROSA: Okay.

(Whereupon, prefiled direct testimony of Karl Rabago was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Tampa Electric Company)	DOCKET NO. 20240026-EI

TESTIMONY OF KARL R. RÁBAGO

ON BEHALF OF

FLORIDA RISING AND LEAGUE OF UNITED LATIN AMERICAN CITIZENS

JUNE 6, 2024

I. INTRODUCTION & WITNESS QUALIFICATIONS

Q. Please state your name, business name and address, and role in this matter.

A. My name is Karl R. Rábago. I am the principal of Rábago Energy LLC, a Colorado limited liability company, located at 1350 Gaylord Street, Denver, Colorado. I appear here in my capacity as an expert witness on behalf of the Florida Rising ("FL Rising") and League of United Latin American Citizens of Florida ("LULAC") ("FL Rising/LULAC").

Q. Please list your formal educational degrees.

A. I earned a Bachelor of Business Administration in Management from Texas A&M University in 1977, a Juris Doctorate with Honors from The University of Texas School of Law in 1984, a Master of Laws in Military Law from the U.S. Army Judge Advocate General's School in 1988, and a Master of Laws in Environmental Law from the Pace University Elisabeth Haub School of Law in 1990.

Q. Please summarize your experience and expertise in the field of utility regulation.

A. I have worked for more than 33 years in the utility industry and related fields, following my honorable discharge from the U.S. Army, where I served as an Armored Cavalry officer and a Judge Advocate. I am actively involved in a wide range of utility regulatory and ratemaking issues across the United States. My previous employment experience includes Commissioner with the Public Utility Commission of Texas, Deputy Assistant Secretary with the U.S. Department of Energy, Vice President with Austin Energy, Executive Director of the Pace Energy and Climate Center, Managing Director with the Rocky Mountain Institute, and

C25-2525

Director with AES Corporation, among others. My resume is attached as Exhibit KRR-1.

Q. Have you ever testified before the Florida Public Service Commission ("Commission") or other regulatory agencies in the past?

A. Yes. I appeared as an expert witness in Commission Docket Numbers 130199-EI, 130200-EI, 130201-EI, 130202-EI, 150196-EI, 160186-EI, 20200176-EI, and 20210015-EI. In the past twelve years, I have submitted testimony, comments, or presentations in utility proceedings in Alabama, Arkansas, Arizona, California, Colorado, Connecticut, District of Columbia, Florida, Georgia, Guam, Hawaii, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Hampshire, New York, North Carolina, Ohio, Pennsylvania, Puerto Rico, Rhode Island, Texas, Vermont, Virginia, Washington, and Wisconsin. I have also testified before the U.S. Congress and have been a participant in comments and briefs filed at several federal agencies and courts. A listing of my previous testimony is attached as Exhibit KRR-2.

Q. Does your experience give you insights into the responsibilities and duties of the Commission in this proceeding?

A. Yes. As a public utility commissioner in Texas, I participated in making decisions on hundreds of rate review, rulemaking, and planning decisions in cases involving investor-owned, municipal, and cooperative electric and telephone utilities. Those matters ranged widely, from ministerial annual interest rate approvals, for example, to prudence and rate decisions on a $12.4 billion nuclear power plant, to mergers and acquisitions. I have appeared before hundreds of commissioners and board members in formal, informal, and educational proceedings in the years since. I have contributed to the writing and passage of laws and rules in many jurisdictions and have made a career of advancing regulatory and market opportunities for competitive alternatives to monopoly control of essential services businesses. I remain honored to have served as a utility regulator and remain deeply respectful of the public interest obligation that comes with the job.

II. <u>OVERVIEW OF TESTIMONY AND RECOMMENDATIONS</u>

Q. Please provide an overview of your testimony in this proceeding.

A. My focus in this testimony is on the spending and associated rates proposed by Tampa Electric Company ("TECO" or the "Company"), a wholly owned subsidiary of Canada-based Emera Corporation ("Emera"). I explain how TECO proposes to regressively increase economic burdens on its residential customers as a condition of electric service. TECO seeks the Commission's support in order to inflate profits for Emera, a foreign holding company, through the extraction of monopoly rents from those customers.

In this testimony I point out how TECO's residential customer electric bills are already among the highest in the nation and would, if the Commission accepts TECO's proposals, go even higher. I show how current and proposed rates excessively burden low users of electricity, who are TECO's lower income customers. And I point out how Emera burdens its Florida customers to an unreasonably higher degree than it does its other regulated utility operating companies.

In this testimony I point out how TECO's residential customer electric bills are already among the highest in the nation and would, if the Commission accepts TECO's proposals, go even higher. I show how current and proposed rates excessively burden low users of electricity, who are TECO's lower income customers. And I point out how Emera burdens its Florida customers to an unreasonably higher degree than it does its other regulated utility operating companies.

Taken as a whole, this rate application by Emera and TECO reflects an aggressive, unjustified, and unreasonable effort to increase the prices that TECO customers must pay for essential electric service, with the burdens of this unjust profit taking intentionally weighted on and shifted to the Florida citizens least able to bear the economic hardships. Overall, the Emera and TECO proposals are inconsistent with sound rate making principles, including cost causation, economic efficiency, gradualism, and fair apportionment of costs.

I identify several key drivers of TECO's proposed rate increases and explain how adjustments to those proposals could mitigate some of the negative impacts on TECO's customers, improve the efficiency of TECO's rates, and encourage more efficient use of electricity by all customers.

Q. What are the key elements of TECO's proposed rates and rate increases?

A. Today, about 64% of Emera's total earnings are taken from Florida.[1] Emera and TECO seek to increase its revenues from Florida customers by about $~~1.162~~ **555** **million** ~~billion~~ over the years 2025 through 2027,[2] with about $~~555 million~~ **about two-thirds** of that increase proposed for 2025.[3] The $555 million in proposed rate increases is based, approximately, on the following key drivers:[4]

$145 million, or about 26% of the total, is pure profit associated with increasing the return on equity ("ROE") and the share of the capital structure to be derived from more expensive equity (as compared to debt).

$185 million, or about 33% of the total, is related to capital investment projects.

$160 million, or about 29% of the total, is related to increased depreciation costs and dismantlement costs to make way for new capital investments.

$40 million, or about 8% of the total, is related to increased operations and maintenance ("O&M") costs for capital investments.

$20 million, or about 4% of the total, is for other proposed spending.

Q. Are the proposed rate increases by Emera and TECO driven by increased customer growth or customer use of electricity?

A. No. TECO's growth in earnings, base revenue growth, and base revenues growth per residential customer are dramatically out of proportion to and unjustified against growth in customer count and energy sales over the years 2018 through 2023.[5] Moreover, the data shows that Emera and TECO profit increases have primarily been on the backs of residential customers.

<u>Table KRR-1: TECO Metrics Growth, 2018-2023</u>

TECO Metrics Growth 2018-2023	Cumulative Growth	Cumulative Growth (%)	Average Growth/Year (%)
Residential Customers (#)	72,058	10.75%	2.15%
Total Customers (#)	77,891	10.30%	2.06%
Energy Sales (MWh)	1,158,489	5.90%	1.18%
Annual Earnings ($)	$ 2,848,655	48.84%	9.77%
Residential Base Revenues ($)	$ 239,606,122	36.12%	7.22%
Total Base Revenues ($)	$ 288,463,684	24.67%	4.93%
Residential Base Revenues per Customer ($)	$ 227	22.91%	4.58%

Q. Can these impacts be seen in TECO residential customers' average bills?

A. Yes. Average TECO residential bills are among the highest in the nation, and the proposed increases would take them even higher. According to the U.S. Energy Information Administration's ("EIA") Sales and Revenue 2023 data and data provided by TECO, the average TECO residential bill under 2023 rates is higher than all other major Florida utilities, higher than the national average by almost 40%, and higher than the average residential electric bills in every other state except Hawai'i and Connecticut.[6]

Q. What recommendations do you offer in this testimony to address these issues and TECO's proposals to further increase customer bills for electricity service?

A. In this testimony, I present a number of recommendations designed to reduce the outsized electric bills and energy burdens faced by TECO's residential customers. These recommendations include:

- Ending TECO's reliance on the Minimum Distribution System ("MDS") method of classifying demand-related costs as customer costs to be recovered through fixed customer charges.
- Reducing TECO's ROE to 9.50%.
- Disallowing use of the 4 Coincident Peak ("CP") method for cost allocation and replacing it with a 12CP methodology.
- Reducing proposed increases in TECO connection and reconnection service charges by 80%.
- Eliminating TECO's proposed Polk fuel oil project.
- Disallowing TECO's South Tampa resilience project absent significant

project funding from the Federal government and/or the U.S. Department of Defense.

- Disallowing further spending on new building construction until TECO produces a comprehensive benefit-cost analysis ("BCA") that fully considers alternatives to new building construction.
- Disallowing all costs related to incentive compensation absent new performance metrics that directly measure improvements in customer affordability, especially among low-income customers, and the removal of incentives for meeting Emera earnings-per-share objectives through methods that worsen affordability.
- Requiring TECO to produce BCAs to support all requests for capital spending projects for $1 million or more.

III. FOUNDATIONAL DATA ON FLORIDA RESIDENTIAL ELECTRIC BILLS

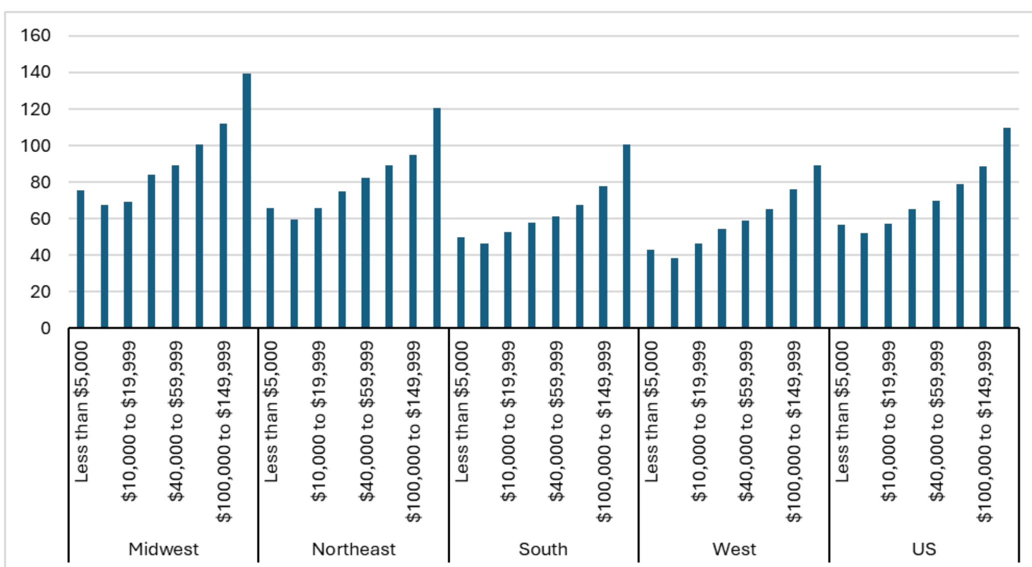
Q. Why are you focused on electric bills for residential customers?

A. Improvements in affordability are a core objective for Florida Rising and the League of United Latin American Citizens. All Florida customers must use electricity to survive—to provide air conditioning and heat, and in the future, to provide motive power for transportation and thermal energy for processes and cooking. In high-use parts of the country like Florida, rates alone are not a meaningful or satisfactory indicator of electric utility performance. Utility energy bills, and bills as a percentage of household income—an affordability metric known as energy burden—are a key indicator of fairness, reasonableness, and justice. Affordability must be a key performance metric for TECO and any electric service provider.

Q. What do we know about average residential electricity usage in Florida?

A. According to the EIA Residential Energy Consumption Survey ("RECS") data the average monthly level of electricity usage by residential customers in Florida is 1,165 kilowatt-hours ("kWh") per month.[7] Lower-income customers across the U.S., on average, use less energy but spend a greater percent of their income on energy costs compared to higher-income customers. According to 2020 EIA RECS data,[8] there is a clear correlation between income and electricity use, with the lowest income customers consuming as little as half as much energy annually compared to their wealthier counterparts. Florida is in the South region and South Atlantic sub-region. The correlation between energy use and income level is also true in Florida.

Figure KRR-1: U.S. Mean Annual Household Energy Consumption by Income Category and Region 2020, million Btu)



Lower income customers, despite using less energy, also suffer from a higher energy burden than higher income customers—their energy bills constitute a

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higher share of their household income.

Q. Why is it important to understand when customers have high energy burdens?

A. Customers with high energy burdens are vulnerable to rate and bill volatility. Month-to-month changes in rates that might not frustrate the household budgets of well-to-do customers can cause rate shock to customers with high energy burdens. Low-income customers often live on the edge of economic or energy insecurity—an inability to meet basic household energy needs that sometimes referred to as the "heat (or cool) or eat" dilemma.[9] An unaffordable electric bill can create a long-lived cascade of household economic problems, made worse with pancaking fees and charges from utilities and other businesses. Energy insecurity is not just an economic issue, but a social and public health matter as well.[10] For these and other reasons, understanding customer energy burdens informs the spending and rates that a utility electric service provider proposes to impose on customers.

Q. What does the data tell us about energy burdens in Florida?

A. The U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy has created a Low-Income Energy Affordability Data Tool ("LEAD Tool") that documents key affordability metrics across the U.S.[11] The latest data is from 2020 and shows that at that time, nearly one million Florida households had income levels below 100% of the Federal Poverty Level,[12] and nearly 2.4 million Florida households had income levels below 200% of the Federal Poverty Level. According to the Florida Department of Health, the number of Floridians living in poverty grew to 2,725,633 in 2022, based on U.S. Census data.[13]

The LEAD Tool data, provided in Table KRR-2, shows that while the overall electricity energy burden in Florida is about 2 percent—meaning that 2% of household income is spent on electricity, the energy burden for customers at or below the poverty level is seven times higher, at 14%, and is three and one-half times higher, at 7%, for Floridians with household incomes at or below twice the poverty level. Even for households with income up to 400% of the poverty level, the electricity energy burden is 50% higher than the statewide average, as shown in Figure KRR-2.

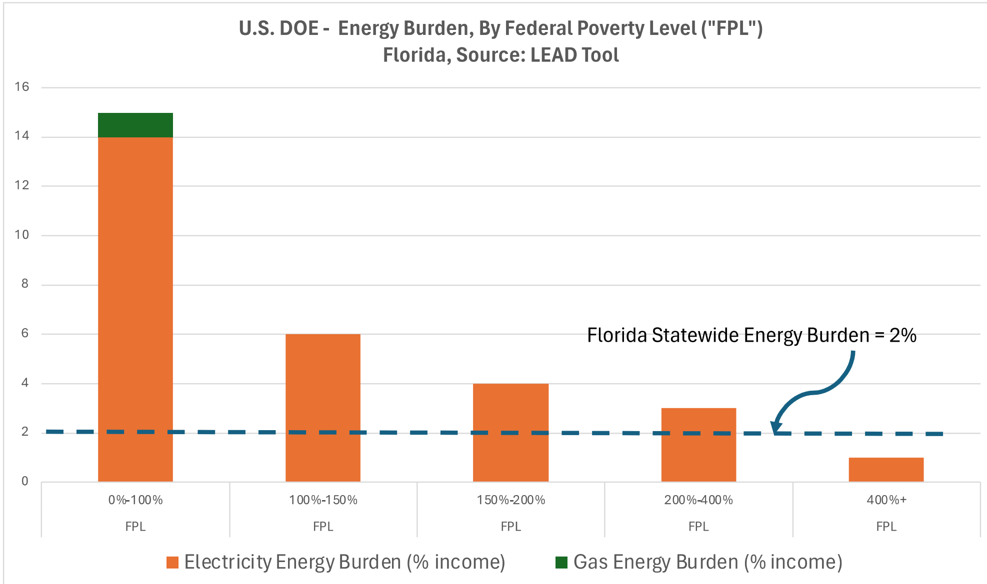
Table KRR-2: Households and Energy Burdens at or below 100% and 200% of Federal Poverty Level

	Households	
	Below 100% FPL	Below 200% FPL
Energy Burden (FL avg = 2%)	14%	7%
Annual Energy Cost	$ 1,428	$ 1,474
2020 Annual Income	$ 10,096	$ 21,868
Number of Households	935,353	2,385,449

Federal Poverty Level (FPL) - 2020	Household of 1	Household of 4
100% of FPL	$ 12,760	$ 26,200
200% of FPL	$ 25,520	$ 52,400

Federal Poverty Level (FPL) - 2024	Household of 1	Household of 4
100% of FPL	$ 15,060	$ 31,200
200% of FPL	$ 30,120	$ 62,400

<u>Figure KRR-2: Florida Energy Burdens by Federal Poverty Level</u>



Q. How do high energy burdens translate into energy insecurity and energy injustice?

A. For TECO's customers living at or below the poverty level, or even twice the poverty level, there is little or no room in the household budget for unexpected costs, or for meeting the increased energy demands of hotter summers and extreme weather events. A $30 added household expense, for example, is one week's worth of electricity for a customer with a monthly bill of $120 and could require months of scrimping and saving to recover from. More importantly, distributional inequity in the levying of new charge and rate increases has an outsize impact on highly burdened households.

Q. Can highly burdened households simply cut back on energy use or use energy more efficiently to reduce their electric bills or the impact of those bills on household budgets?

A. No. Energy efficiency measures cost money, and even spending an extra $20 on efficient light bulbs is beyond the financial ability of household budgets facing high energy burdens. The housing that low-income customers live in is, as a rule, highly inefficient. Customers in rental property have no control over aspects of their homes that contribute most to cooling and heating bills—insulation, air conditioner and heater efficiency, windows, and major appliances. Many low-income customers are also on fixed incomes and already practice energy rationing—there is little or no room for further privation or curtailment, especially for the elderly and infirm.

Q. What does TECO know about its customers' household income levels?

A. Very little. TECO is not able to provide data about the numbers of customers whose household incomes are at or up to 200% of the Federal poverty level.[14]

Q. What does TECO say about the importance of maintaining affordable rates for its residential customers?

A. Practically nothing. As a former combat arms U.S. Army officer, I look to what leaders say to initially gauge the culture and climate of an organization. I reviewed the testimony of Mr. Archie Collins,[15] who holds the title of president and chief executive officer for TECO for what he said about affordability and found that the words "affordable" or "affordability" do not appear at all. While Mr. Collins asserts that TECO has a strategic objective of creating value for customers,[16] none of his description of that objective directly references affordable rates. Mr. Collins asserts that investments in fossil generation plant improvements and life extensions and new solar will save customers on fuel costs.[17] Those savings are merely incremental in a system that relies on climate-changing fossil fuels for 88% of its generation capacity.[18]

Q. In the face of the basic facts, what has TECO proposed in this rate increase application?

A. Emera and TECO propose excessive new costs for customers and an unconscionably regressive assignment of those costs to its customers who can least afford the burden. As show in Table KRR-3,[19] the lowest users of electricity—who are also amongst TECO's least-wealthy customers—are slated to bear shocking base rate and bill increases if the Commission approves TECO's rates and rate designs. As shown in the table, all residential customers using less than the average monthly amount of electricity would see a 10% or greater increase in their bills, while the wealthiest customers who use three times as much electricity as average would only see bills increase by 5%.

Table KRR-3: TECO Proposed Bill Increases by Usage Level, in $ and %[20]

	TECO		
kWh/Month	DOLLARS		PERCENT
100	$	11.71	34%
250	$	12.67	24%
500	$	14.27	17%
750	$	15.86	14%
1000	$	17.46	12%
1165	$	18.25	11%
1250	$	18.66	10%
1500	$	19.87	9%
2000	$	22.28	8%
3000	$	27.10	6%
5000	$	36.74	5%

Q. How do Emera and TECO seek to impose these unjust rates?

A. TECO's tools of choice are fixed and unavoidable charges, massive and unjustified capital spending projects, unreasonable increases in cost-plus profits added to spending, and the use of a cost allocation methodology for plant costs that unjustly burdens residential customers. I address these issues further in this testimony.

IV. TECO'S RESIDENTIAL FIXED CUSTOMER CHARGE PROPOSAL IS FLAWED AND UNJUST, AND THE COMMISSION SHOULD DIRECT TECO TO INSTEAD USE THE BASIC CUSTOMER METHOD

Q. What is your recommendation to the Commission regarding TECO'S proposed fixed customer charges and the methods used by TECO to calculate the proposed charges?

A. The Commission should reject the TECO's proposed fixed customer charges and instead approve a fixed customer charge of no more than $0.43 per customer per day for the residential class, based on a re-calculation of customer costs that excludes demand costs incorrectly classified as customer costs under the Minimum Distribution System ("MDS") method proposed by the Company. With that step, the current proposed fixed customer charge would be reduced by more than half. TECO should be further directed to eliminate other cost classifications that are demand-related in order to further reduce the approved fixed customer charge. The Commission should further direct TECO to calculate fixed customer charges only using the basic customer method and to allocate any demand-related changes in revenue requirement to volumetric base rates. Finally, the Commission should direct TECO to use only the basic customer method in all future general rate cases.

Q. What fixed customer charge does TECO propose for residential customers?

A. The Company proposes to increase the current daily per-customer fixed customer charge of $0.71 to $1.07—an increase of $0.36 or 51%.

Q. What does TECO calculate as customer costs in this proceeding?

A. TECO witness Jordan Williams describes the way that TECO classifies demand related costs as customer costs under the MDS.[21] TECO's MDS is based on a fantasty hypothetical distribution system sized to meet the demands of its customers when those customers use no energy and place no demand on the system. The MDS uses mathematical formulae[22] to extrapolate these artificial costs for a distribution system that is sized to meet load[23] but then serves no load because it is installed "in readiness."[24] TECO assigns those artificial costs to customers as customer costs. This assignment is made despite TECO's assertion that customer costs are costs associated with customer "connectivity" to the grid and are not related to capacity requirements[25] and that TECO defines demand costs as costs associated with customer maximum load requirements,[26] and despite the fact that customers don't connect to the grid in order to *not* use energy.

Q. Does TECO's MDS approach account for variation in customer geographic density, or for the fact that low use customers require much less expensive connectivity investments than high users?

A. No. The MDS that TECO uses is designed to extract monopoly rents from customers despite the actual costs associated with establishing their connection to the grid,[27] and even though when customers use the grid, they use it at very different levels—levels that are reflected in the sizing of distribution system components. Simply stated, TECO eschews the most fundamental cost of service rate making principle—cost causation—so as to charge customers for costs they do not cause simply by becoming customers under a rate that customers cannot avoid. Under TECO's approach, low use customers who require much smaller and less expensive distribution system investments are required to subsidize the higher demand-related costs of larger, wealthier users. TECO uses the MDS to perpetrate a massive cost shift.

Q. How does TECO justify its use of such a regressive and unjust method of classifying customer costs?

A. TECO asserts that its MDS approach aligns with the NARUC Electric Utility Cost Allocation Manual. However, the NARUC Cost Allocation Manual is descriptive and not normative; it does not serve as justification for use of the minimum system and minimum or zero intercept methods.[28]

Q. How do differences in fixed customer charges emerge from different methods used to classify cost when they all start from a single common pool of cost-of-service data?

A. The differences arise based on which costs are classified as customer costs and whether the utility performs calculations on underlying data to classify demand-related costs as customer costs. The basic customer method identifies costs that vary only with the number of customers—costs that are incurred to connect a customer to the network. The zero intercept and minimum system methods, like TECO's MDS approach, classify costs as customer costs that are related to meeting customer demand for energy and which are not actually caused by connection of the customer to the grid. Again, these minimum system methods mathematically extrapolate from costs incurred to meet demand, and hypothetically reflect the costs of infrastructure to serve customers who use no energy at all.

Q. Does the method of classifying customer costs impact the total amount of revenue requirement reflected in rates?

A. No. Under the zero-sum process of rate design, lower fixed charges mean more revenue is recovered in volumetric rates; higher fixed charges result in lower volumetric rates. In both, the total revenue to be collected is the same.

Q. Does it matter, then, whether costs are collected through a fixed charge or through a volumetric charge?

A. Yes, very much so. Fixed charges are inherently regressive—they have greater cost impact on low-users who are often also low-wealth customers. Guaranteeing non-bypassable revenues through high fixed customer charges is extremely desirable to TECO and Emera in order to meet the expectations for steady generation of profits promised to investors. Guaranteeing recovery of fixed costs associated with infrastructure spending, as occurs when these costs are recovered through a non-bypassable fixed customer charge, creates an incentive for the utility to increase that kind of spending. Increasing fixed non-bypassable charges has an impact on the cost-effectiveness of energy efficiency, distributed generation, and other distributed energy resource ("DER") investments by customers because higher non-bypassable charges means lower volumetric rates and therefore result in longer payback on customers' investments designed to reduce usage of utility-

C25-2541

supplied energy. In sum, the decision about whether to recover costs through fixed charges or volumetric rates is a decision about what price signals the rate sends—both to customers and to the utility; it is a fundamental question of rate design.

Q. Why do you say that high fixed charges for residential electric are economically regressive?

A. It is a matter of simple math that high fixed charges have greater impacts on low users of electricity and gas services because more of their monthly bill is fixed and non-bypassable. These impacts become economically regressive when there is a high correlation between low usage rates and lower household incomes. My testimony has demonstrated that this correlation exists in Florida and among TECO's customers.

Q. Are there other disparate impacts from high fixed charges on lower-income customers?

A. Yes. In my experience, low users of electricity have lower and flatter load curves—less peaky demand—than high users. As a result, when peak-driven demand-related costs are allocated to the residential class and some of those costs are included in fixed customer charges, low-use, often low-wealth customers are required to pay more than their fair share of these costs. As a result of TECO's reliance on the MDS approach to classify customer costs, low-wealth customers are being charged for costs driven by the usage levels and patterns of more well-to-do, higher-demand customers. When fixed customer charges do not differentiate between the usage levels and patterns of customers as TECO's charges fail to do,[29] they unjustly discriminate.

Q. How do high fixed customer charges discourage adoption and weaken the economics of energy efficiency, conservation, and distributed renewable energy?

A. High fixed charges work against energy policy and rate making goals favoring and encouraging energy efficiency and increased use of renewable energy resources in two insidious and overlapping ways. First, they increase the amount of the customer's total bill that cannot be reduced through efficiency, conservation, renewable energy subscription, or self-generation. This makes customer actions that would increase efficiency, conservation, and customer participation in renewable generation less likely to occur. Second, in the zero-sum-game of rate design, the charges also result in lower volumetric rates. This has the effect of reducing the marginal value of energy efficiency, conservation, and customer-sited renewable generation, also making those actions less likely to occur. For example, when use-based charges are deflated by 20% by shifting the revenue requirement to the fixed charges, every efficiency measure, conservation practice, and solar investment takes 20% longer to deliver a payback on its initial investment. As a result of these two effects, basic economics dictates that customers are less interested in reducing usage because it will yield less benefit in reducing bills. I have seen no evidence that TECO has conducted or used a demand elasticity study—an analysis to determine how usage behaviors change in response to price changes—to inform its rate design proposals.

Q. As high fixed cost businesses, should utilities impose high fixed charges in order to align rate structure with cost structure?

A. No. As far as I can tell, TECO does not directly assert that it should charge high fixed customer charges just because it has high fixed costs. Rather, TECO takes an indirect path: TECO's position is that it should be charging higher fixed customer charges because it uses a method that classifies higher amounts of fixed costs as customer costs—an intentional choice of classification method that inexorably leads to the same result—higher fixed charges.

Before I address the significant flaws in the MDS method used by TECO and in other minimum system or zero-intercept methods, it is important to address the oft-heard argument that rate design should mimic cost structure. In that regard, I simply note that after thirty years in utility regulation I have yet to find a single authoritative economic text to support the argument that economic efficiency results from mimicking cost structure in rate design.

Q. Are there competitive businesses with high fixed costs that impose high fixed charges?

A. There are very few. The vast majority of high fixed-cost businesses do not impose fixed charges at all and would likely not survive long in a competitive market if they did. For example, airlines and transit services do not require monthly subscriptions, neither do hotels or shopping malls. There are some businesses like warehouse retailers and on-line shopping services with optional levels of fixed charges, but those charges appear designed to increase sales to loyal customers—which, in the electric utility regulatory setting would be called "load building." The fact that many businesses must make large fixed-cost investments does not translate into fixed charges in almost all business cases; rather, the forces of competition reward business for careful investment analysis, inventory management, and cost control—all disciplines that if mastered would greatly

C25-2544

improve the performance of electric and gas utilities far more than a guarantee of fixed costs recovery through non-bypassable customer charges.

Q. Do any other Emera operating utilities employ the MDS or other minimum system or zero-intercept approaches?

A. No.[30]

Q. Isn't economic efficiency improved when prices reflect marginal costs?

A. Yes, prices advance efficiency when they reflect marginal costs, but that is an entirely different issue than reflexively asserting that fixed charges should be used to collect marginal fixed costs as a matter of rate design. Marginal costs can be recovered through either fixed or variable charges. By weakening the price signal that customers see from marginal changes in consumption, high fixed charges deviate from marginal cost pricing.

Q. How has TECO analyzed price signal impacts from its high fixed charges for electric service?

A. TECO provided "typical bill" calculations of the bill impacts of its rate proposals via MFR filings, but it has not otherwise studied the impacts of its proposed rates on residential customers, or upon low-wealth customers in particular.

Q. Are high fixed charges and methods that assign higher levels of customers costs appropriate as a mechanism to ensure that low-use customers pay their fair share of demand-related fixed costs?

A. No. Some utilities attempt to justify higher fixed customer charges on the basis

C25-2545

that when large amounts of costs are classified as customer costs, higher fixed charges are necessary to avoid subsidization of low-use customers by high-use customers. This argument is a logical fallacy known as “begging the question.” That is, it assumes that the minimum system and zero-intercept methods that classify more costs as customer costs are themselves sound rate making methods in order to justify assigning more costs for recovery through fixed customer charges. These arguments are seldom accompanied by anything but an assumption that because low users pay less in fixed costs than the *average* customer in the class, they are not paying enough.

Q. What costs should be charged on a per-customer basis?

A. Where a customer charge is used, a good rule of thumb is this: If the cost disappears because the customer leaves the system, the cost is a customer cost. The consumption function of the meter, the service drop, and a reasonable share of customer service spending would all meet this test, and therefore these costs are included in approaches like the basic customer method. Likewise, if the cost remains after a customer leaves the system, the cost is not a customer cost. Transformers, secondary and primary distribution lines, program-specific marketing and customer care expenses, uncollectible costs, and general operations, administrative and maintenance expenses and taxes are all non-customer costs, and the principle of cost-causation dictates that those costs should not be recovered through a fixed or customer charge.

Q. Please provide more detail on how costs are classified to the customer costs category?

A. Some costs can be easily and objectively classified as customer costs. In general, the customer costs are the costs incurred to connect a new customer to basic electric service. These include the cost of establishing service, which includes a fraction of a customer accounts system, billing software, and the time that customer service representatives spend on establishing new accounts. These costs are all costs that pass the simple test—they go away if the customer goes away. These costs also include the costs related to the consumption function of meter purchase, installation, activation, and service, but not the entire costs of modern meter functions. And these costs include the incremental costs of the service drop from the last, smallest transformer to the customer meter box. These costs are classified as customer costs under the dominant method for classifying customer costs—the basic customer method. In my opinion, this is the most appropriate method.

In other words, the customer costs category and, therefore, the customer charge, should reflect no more than the costs incurred by the utility to connect the average customer to the electric system for service. I would note that the strongest price signals would be sent under the "new customer" method, which only charges customers with the incremental connection costs for new customers on a per-customer basis, and which I believe the Commission should order TECO to study in preparing its next general rate application.

Q. Are there any well-accepted references that comport with your view that the basic customer method is most appropriate for use in classifying customer costs?

A. Yes. In 1961, James C. Bonbright defined customer costs as follows:

> [The customer costs] are those operating and capital costs found to vary with number of customers regardless, or almost regardless, of power consumption. Included as a minimum are the costs of metering and billing along with whatever other expenses the company must incur in taking on another consumer.[31]

Simply stated, Bonbright's definition—which describes the basic customer method—ensures that the customer charge should be limited to the marginal cost of connecting the customer to the grid and should include only costs that vary directly with the number of customers.[32]

Q. Are there any benefits to relying on Bonbright's definition of customer costs in building the customer charge?

A. Adhering to the principle that customer costs are costs that vary with customer count and almost or entirely without regard for usage advances other ratemaking principles such as equity and cost-causation and preserves the power of volumetric charges as a price signal. Residential customers can see a direct correlation, both positive and negative, between their level of usage and their contributions to cost creation when energy- and demand-related costs are recovered through volumetric charges. Allocating demand-related costs or even unallocable costs (as Bonbright viewed the minimum system costs) to the fixed customer charge eliminates, or at least severely weakens, the price signal impact.

Q. How much cost does connecting a new customer cause?

A. Costs directly related to grid connection for new customers include a portion of the cost of a meter, billing and metering services, and collection costs—in Bonbright's words, the costs the utility "must incur in taking on another customer."[33] By my calculation, the figure is less than 43 cents per customer per day for TECO residential customers.

Q. Are all the costs classified by TECO as customer costs the costs that TECO incurs to connect a customer to the grid?

A. No. TECO explicitly includes costs that are associated with meeting customer demand for energy services and that are not directly related to customer connection.[34]

Q. Have the problems associated with the minimum system approach been previously studied or analyzed?

A. Yes. The problems inherent in the minimum system approach have been well understood for decades. Indeed, James Bonbright addressed the issues head-on in 1961:

> [T]he really controversial aspect of customer-cost imputation arises because of the cost analyst's frequent practice of including, not just those costs that can be definitely earmarked as incurred for the benefit of specific customers but also a substantial fraction of the annual maintenance and capital costs of the secondary (low-voltage) distribution system—a fraction equal to the estimated annual costs of a hypothetical system of minimum capacity. This minimum capacity is sometimes determined by the smallest sizes of conductors deemed adequate to maintain voltage and to keep from falling of their own weight. In any case, the annual costs of this phantom, minimum-sized

distribution system are treated as customer costs and are deducted from the annual costs of the existing system, only the balance being included among those demand-related costs to be mentioned in the following section. Their inclusion among the customer costs is defended on the ground that, since they vary directly with the area of the distribution system (or else with the lengths of the distribution lines, depending on the type of distribution system), they therefore vary indirectly with the number of customers.

What this last-named cost imputation overlooks, of course, is the very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system. For it makes no allowance for the density factor (customers per linear mile or per square mile). Indeed, if the company's entire service area stays fixed, an increase in number of customers does not necessarily betoken any increase whatever in the costs of a minimum-sized distribution system.

While, for the reason just suggested, the inclusion of the costs of a minimum-sized distribution system among the customer-related costs seems to me clearly indefensible, its exclusion from the demand-related costs stands on much firmer ground. For this exclusion makes more plausible the assumption that the remaining cost of the secondary distribution system is a cost which varies continuously (and, perhaps, even more or less directly) with the maximum demand imposed on this system as measured by peak load.

But if the hypothetical cost of a minimum-sized distribution

> system is properly excluded from the demand-related costs for the reason just given, while it is also denied a place among the customer costs for the reason stated previously, to which cost function does it then belong? The only defensible answer, in my opinion, is that it belongs to none of them. Instead, it should be recognized as a strictly unallocable portion of total costs. And this is the disposition that it would probably receive in an estimate of long-run marginal costs. But the fully-distributed cost analyst dare not avail himself of this solution, since he is the prisoner of his own assumption that 'the sum of the parts equals the whole.' He is therefore under impelling pressure to 'fudge' his cost apportionments by using the category of customer costs as a dumping ground for costs that he cannot plausibly impute to any of his other cost categories.[35]

Thus, as the late professor correctly noted, the minimum system analysis does not identify customer costs but partially non-demand and partially non-energy costs. Using it to set a customer charge is nothing more than a preference to socialize the costs rather than have customers pay for them based on usage.

Q. Have more modern articulations of generally accepted rate making principles than Bonbright addressed the minimum system and minimum and zero intercept methods?

A. Yes, in 2020, the Regulatory Assistance Project published a new manual for electric cost allocation that addresses minimum system and minimum and zero intercept methods.[36] I reprise the discussion from the RAP Cost Allocation Manual in great detail because of the thoroughness of its explanation:

> [M]ore general attempts by utilities to include a far greater portion of shared distribution system costs as customer-related are frequently unfair and wholly unjustified. These methods include straight fixed/variable approaches where all distribution costs are treated as customer-related . . . and the more nuanced minimum system and zero-intercept approaches included in the 1992 NARUC cost allocation manual.
>
> The minimum system method attempts to calculate the cost (in constant dollars) if the utility's installed units (transformers, poles, feet of conductors, etc.) were each the minimum-sized unit of that type of equipment that would ever be used on the system. The analysis asks: How much would it have cost to install the same number of units (poles, feet of conductors, transformers) but with the size of the units installed limited to the current minimum unit normally installed? This minimum system cost is then designated as customer-related, and the remaining system cost is designated as demand-related. The ratio of the costs of the minimum system to the actual system (in the same year's dollars) produces a percentage of plant that is claimed to be customer-related. This minimum system analysis does not provide a reliable basis for classifying distribution investment and vastly overstates the portion of distribution that is customer-related. Specifically, it is unrealistic to suppose that the mileage of the shared distribution system and the number of physical units are customer-related and that only the size of the components is demand-related, for at least eight reasons.

1. Much of the cost of a distribution system is required to cover an area and is not sensitive to either load or customer number. The distribution system is built to cover an area because the total load that the utility expects to serve will justify the expansion into that area. Serving many customers in one multifamily building is no more expensive than serving one commercial customer of the same size, other than metering. The shared distribution cost of serving a geographical area for a given load is roughly the same whether that load is from concentrated commercial or dispersed residential customers along a circuit of equivalent length and hence does not vary with customer number . . .

2. The minimum system approach erroneously assumes that the minimum system would consist of the same number of units (e.g., number of poles, feet of conductors) as the actual system. In reality, load levels help determine the number of units as well as their size. Utilities build an additional feeder along the route of an existing feeder (or even on the same poles); loop a second feeder to the end of an existing line to pick up some load from the existing line; build an additional feeder in parallel with an existing feeder to pick up the load of some of its branches; and upgrade feeders from single-phase to three-phase. As secondary load grows, the utility typically will add transformers, splitting smaller customers among the existing and new transformers. Some other feeder construction is designed to improve reliability (e.g., to interconnect feeders with automatic switching to reduce the number of customers affected by outages and outage

duration).

3. Load can determine the type of equipment installed as well. When load increases, electric distribution systems are often relocated from overhead to underground (which is more expensive) because the weight of lines required to meet load makes overhead service infeasible. Voltages may also be increased to carry more load, requiring early replacement of some equipment with more expensive equipment (e.g., new transformers, increased insulation, higher poles to accommodate higher voltage or additional circuits). Thus, a portion of the extra costs of moving equipment underground or of newer equipment may be driven in part by load.

4. The “minimum system” would still meet a large portion of the average residential customer’s demand requirements. Using a minimum system approach requires reducing the demand measure for each class or otherwise crediting the classes with many customers for the load-carrying capability of the minimum system.

5. Minimum system analyses tend to use the current minimum-sized unit typically installed, not the minimum size ever installed or available. The current minimum unit is sized to carry expected demand for a large percentage of customers or situations. As demand has risen over time, so has the minimum size of equipment installed. In fact, utilities usually stop stocking some less expensive small equipment because rising demand results in very rare use of the small equipment and the cost of maintaining stock is no longer warranted. However, the transformer industry could produce truly minimum-sized utility

transformers, the size of those used for cellular telephone chargers, if there were a demand for these.

6. Adding customers without adding peak demand or serving new areas does not require any additional poles or conductors. For example, dividing an existing home into two dwelling units increases the customer count but likely adds nothing in utility investment other than a second meter. Converting an office building from one large tenant to a dozen small offices similarly increases customer number without increasing shared distribution costs. And the shared distribution investment on a block with four large customers is essentially the same as for a block with 20 small customers with the same load characteristics. If an additional service is added into an existing street with electrical service, there is usually no need to add poles, and it would not be reasonable to assume any pole savings if the number of customers had been half the actual number.

7. Most utilities limit the investment they will make for low projected sales levels, as we also discuss in Section 15.2, where we address the relationship between the utility line extension policy and the utility cost allocation methodology. The prospect of adding revenues from a few commercial customers may induce the utility to spend much more on extending the distribution system than it would invest for dozens of residential customers.

8. Not all of the distribution system is embedded in rates, since some customers pay for the extension of the system with contributions in aid of construction, …. Factoring in the entire length of the system,

including the part paid for with these contributions, overstates the customer component of ratepayer-funded lines.

Thus, the frequent assumption that the number of feet of conductors and the number of secondary service lines is related to customer number is unrealistic. A piece of equipment (e.g., conductor, pole, service drop or meter) should be considered customer-related only if the removal of one customer eliminates the need for the unit. The number of meters and, in most cases, service drops is customer-related, while feet of conductors and number of poles are almost entirely load-related. Reducing the number of customers, without reducing area load, will only rarely affect the length of lines or the number of poles or transformers. For example, removing one customer will avoid overhead distribution equipment only under several unusual circumstances. These circumstances represent a very small part of the shared distribution cost for the typical urban or suburban utility, particularly since many of the most remote customers for these utilities might be charged a contribution in aid of construction. These circumstances may be more prevalent for rural utilities, principally cooperatives.

The related zero-intercept method attempts to extrapolate from the cost of actual equipment (including actual minimum-sized equipment) to the cost of hypothetical equipment that carries zero load. The zero-intercept method usually involves statistical regression analysis to decompose the costs of distribution equipment into customer-related costs and costs that vary with load or size of the equipment, although some utilities use labor installation costs with no equipment. The idea is that this procedure identifies the amount of equipment required to connect existing customers that is not load-related (a zero-kVA transformer, a zero-ampere conductor or a pole that is zero feet high). The zero-intercept regression analysis is so abstract that it can produce a wide range of results, which vary depending on arcane statistical methods and the choice of types of equipment to include or exclude from an equation. As a result, the zero-intercept method is even less realistic than the minimum system method.[37]

Q. What should TECO do to determine customer-related costs and ultimately build a just and reasonable customer charge?

A. The Company should use the basic customer method. The RAP Cost Allocation Manual provides additional explanatory detail that the Company should consult.[38]

Q. Are the minimum system and zero-intercept methods common practice in the majority of states?

A. No. The minimum system method is out of step with practice in the majority of states.[39] The RAP Cost Allocation Manual cites several regulatory decisions that have rejected the methods.[40]

Q. If, as Bonbright suggests, some of the legitimate and reasonable costs that TECO's MDS allocates to the customer cost category are not customer costs or demand-related costs, then how do you propose that TECO recover those

costs?

A. First, it is important to recognize that there is no general principle of rate making that requires a cost to be recovered through a particular kind of charge solely because of the category to which the cost is assigned.[41] Rate design is a separate rate making step following cost of service analysis, functionalization, and classification. Given the important policy, equity, and market issues that I discuss in this testimony, prudent distribution system costs properly allocated to residential customers that may not neatly fit in the customer or demand category should be recovered through the volumetric delivery charge. The typically high correlation between energy use and demand means that assignment of transmission and distribution costs (other than the costs to connect) to volumetric rates creates a more efficient price signal than assigning those costs to fixed customer charges.

Q. Does the minimum system method support just, reasonable, and equitable rates?

A. No. The major problem with the minimum system methods is that they are designed to meet a predetermined revenue recovery level choice rather than to reflect, as best is possible, objective reality about system costs and cost-causation. Indeed, the underlying policy choice made in adopting minimum system methods is that costs should not be paid according to causation and, instead, socialized. The minimum system methods assign all customers a per-customer share of the system costs regardless of the very real differences in the cost to connect and serve different kinds of customers, even customers in the same class.

Q. Do TECO's fixed charges proposals raise any other economic efficiency concerns?

A. Yes. I have explained how the increased fixed charges and companion lower base volumetric rates are economically regressive and send price signals that disincentivize investment in energy efficiency and distributed generation. They also send the wrong price signal to TECO and Emera. When marginal distribution infrastructure costs are allocated to volumetric rates, demand elasticity means that sales will go down as customers seek alternatives to high usage and higher bills. In this way, a Commission decision to limit the costs that can be loaded into fixed charges serves as the classic substitute for the forces of free market competition. Conversely, the utility that is allowed to increase spending and allocate those costs to non-bypassable charges will have less incentive to operate and spend in a least-cost manner because it will be immunized, to a degree, from consumption changes that accompany higher prices. That is, a higher fixed customer charge can encourage economic inefficiency and waste, *and* stronger revenues by the Company. Revenues that a regulated monopoly can extract from customers without fear or with reduced fear of consumption changes are called monopoly rents—neither markets nor regulatory commissions should encourage them by allowing high-fixed charge rate designs.

Q. Please summarize your testimony on this issue. If some of the minimum system costs are, according to Bonbright, neither pure customer costs nor pure demand costs, how should they be treated?

A. It is important to start with the reminder that the only fixed and variable costs included in the customer charge should be those true customer costs that would go away in the absence of the customer. Then, the decision on how to treat minimum system costs that are not customer or demand costs should be informed by policy. On the one hand, recovering these costs on a per-customer basis enriches shareholders with more certain revenue recovery; increases the incentive for profit-generating infrastructure investments even if not cost-effective; decreases the incentive for energy efficiency, conservation, and distributed generation investment; and weakens price signals relating to fixed costs creation in general. The alternative is recovering these costs on a volumetric basis, as is done in the majority of states. This alternative provides incentives to customers to become more efficient and to invest in clean distributed generation, sends stronger price signals to the utility to manage and reduce infrastructure costs, aligns bill impacts with customer cost-causation, and aligns with generally-accepted rate design and energy policy goals.

Q. What do you conclude about the fixed charges proposed for approval in this case?

A. The charges are too high because they unjustly and unreasonably charge customers for costs that are not customer costs, and they are bad rate making policy. TECO has calculated an unreasonable residential customer charge of $1.07 per customer per day based on its MDS method that should not be approved by the Commission.

Q. What residential fixed customer charge should the Commission approve?

A. The Commission should approve a fixed customer charge for residential customers based on treatment of MDS costs as demand costs. I calculate, using TECO data, that a reasonable customer charge should be to be no higher than $0.43 per customer per day.

Q. Why do you say that the residential fixed customer charge should be *no higher* than 43 cents per customer per day?

A. Consistent with my testimony, the Commission should also direct TECO to exclude from the calculation of the residential customer charge additional amounts that are not true customer costs. TECO records all customer relations and customer service expenses as customer costs.[42] However, according to TECO, only about 12% of the customer service call volume is related to turning on service and connecting customers to the grid.[43] The remainder of customer service expenses relates to account issues, service disconnections, payment issues, and other activities that are associated with ongoing customer use of electric services.[44] Likewise, uncollectible expenses are directly a result of use of energy and demand and are not basic customer costs.

TECO also deploys various sizes and types of equipment and infrastructure to connect customers to the grid. The costs that should be classified as customer costs should only be those associated with the smallest, least expensive equipment necessary to connect customers to ensure that low users of electricity are not required to subsidize the equipment and infrastructure needs of larger consumers with higher demand for electricity. The Commission should direct TECO to further reduce the residential fixed customer charge by eliminating connection costs attributable only to larger users.

Making these changes will reduce the level of a just and reasonable residential fixed customer charge below the 43 cents per customer per day that I initially calculate.

Q. How do you propose that TECO recover demand-related costs that should not be recovered through fixed customer charges?

A. I propose that the adjustments to remove the effects of TECO's use of the MDS approach be addressed in a revenue neutral manner. That is, any just and reasonable costs that are not collected through the customer charge should be assigned as demand related and recovered through the residential volumetric charge.

Q. What effect does the classification of demand-related distribution costs have on volumetric rates?

A. My proposal has three primary impacts. First, it removes a significant amount of the regressive nature of TECO's proposed rates and better aligns overall rates with cost causation. This change empowers low-use and low-income customers to better manage their electric bills through changes in usage and behavior to the extent that they can or can be helped to do so. Second, it increases the volumetric rates, sending a more efficient price signal to high users and reflects the fact that high users drive distribution system costs. This in turn improves the economics of efficient use and efficiency programs, self-generation, and reliance on zero- or low-marginal cost resources like solar energy. Third, the changes will send better price signals to TECO relating to its level of distribution spending.

I will provide a table of estimated bill impacts later in this testimony that includes the elimination of the MDS approach as well as my recommendation for TECO's allowed ROE.

C25-2562

V. TECO'S ROE AND CAPITAL STRUCTURE PROPOSALS ARE EXCESSIVE AND UNJUSTIFIED, AND SHOULD BE REDUCED

Q. What allowed ROE and equity fraction does TECO propose?

A. TECO proposes a midpoint allowed ROE of 11.50%, with potential for earning up to 12.50% in this rate proceeding.[45] TECO also proposes a 54% equity ratio from investor sources.[46]

Q. How does TECO justify its ROE and capital structure requests?

A. After reviewing the testimony of TECO witnesses Chronister and D'Ascendis, upon whom TECO's profit requests primarily rely, I find that TECO's argument boils down to the fact that it wants to spend a lot of money and that it wants to make a lot of money when it does so. TECO presents no evidence of financial impairment or difficulties in obtaining capital at reasonable rates. As discussed in this testimony, a significant amount of TECO's proposed spending is excessive and unjustified. Although TECO's primary ROE witness, Dylan W. D'Ascendis, modifies and applies several analysis models to argue that the proposed ROE and capital structure are reasonable,[47] his arguments can be boiled down to four: (1) interest rates and inflation were higher when this rate application was prepared than they were in previous years; (2) TECO proposes to spend a lot of money; (3) TECO should earn profits at levels that are indexed against those of unregulated businesses; and (4) TECO's profits should be inflated because it faces high risk based on the potential costs associated with extreme weather events.[48]

Q. Do you agree with these justifications?

C25-2563

A. No, and for several reasons. As I have testified, TECO's primary business drivers of customer and sales growth have been extremely modest in effect and do not justify the dramatic increases in spending and earnings that TECO has experienced and proposed. TECO is overearning against these drivers and its spending and profits should be reduced, not further inflated. Second, TECO's proposed new spending is unreasonable and unjustified in many cases. If these proposals were moderated to reasonable levels, TECO could maintain strong financials without making outsized profits. TECO wants to spend about $1.6 billion each year in 2025, 2026, and 2027 on capital projects, growing its rate base and profits.[49] Third, TECO's ROE proposal is out of step with awarded ROEs in recent years. According to the Edison Electric Institute ("EEI"), awarded ROEs since the start of 2022 have averaged 9.52%, as have awarded ROEs dating back for five years.[50] In fact, awarded ROEs over the past ten years have been only slightly higher, at 9.67%.[51] Fourth, TECO's proposed ROE and capital structure are out of step with the allowed rates of return for all other Emera operating companies.[52] Fifth, the Federal Reserve Bank is continuing efforts to control inflation and resume interest rate reductions.[53] Sixth, while TECO faces climate change risks associated with severe weather events, such risks are now unfortunately common across the U.S. and around the world. TECO has finally started taking some steps towards reducing its dependence on fossil fuels, and if it is serious about climate risk, should continue those efforts.[54] In addition, if TECO wants to protect investors, it should not do so with outsized profits for a risky system, but through concerted planning and efforts to change the basic structure of its system, including through more aggressive support for deployment of distributed energy resources such as distributed storage, distributed generation, energy efficiency, strengthen building codes and standards, and other similar measures. TECO's risk profile and actions to date do not justify returns that are out of step with regulated electric utility averages.

Q. Why, in particular, isn't increasing TECO profits a solution for increased climate-related severe weather events?

A. Climate-related severe weather events don't just impact TECO. They create massive problems throughout local and national economies and society as a whole. To propose that TECO profits be increased on the backs of TECO's customers, especially residential customers, in order to compensate TECO for the risk of running the electric utility ignores the very real suffering and hardships imposed on those customers all year round. In this case, TECO proposes increases in climate-damaging fossil fuel emissions and excess profits on those increases. Regulation that acts as a substitute for competition should not and would not award excess profits for excessively risky investments and behavior. Money spent on excess utility profits can't be spent on storm recovery or substitute for work interruption-related loss of income.

Q. What allowed ROE do you recommend that the Commission approve for TECO?

A. Unless and until TECO shows that it is not seeking to grow Emera profits on the backs of Florida residents, and it offers a comprehensive plan for mitigating and not exacerbating its contributions and exposure to climate-related severe weather, TECO's allowed ROE should not exceed the average awarded to other utilities, including other Emera utilities. For these reasons, I recommend that the

C25-2565

Commission award TECO a midpoint ROE of no higher than 9.50%.

Q. What impact would an allowed ROE of 9.50% have on TECO's revenue requirements and rates?

A. Based on the information provided by TECO in this case, I estimate that an allowed ROE of 9.50% would reduce the overall revenue requirements by about 7%. According to TECO, a 200 basis point reduction in the allowed ROE from 11.50% to 9.50% will reduce TECO's total revenue requirement by more than $123 million and provide a significant improvement in electric service affordability.

Q. What is the combined impact of your proposal to eliminate the MDS approach and to reduce the allowed ROE to 9.50%?

A. While TECO would have to provide the exact amounts, I estimated that the rates and bills resulting from eliminating the MDS approach and an ROE midpoint of 9.50%. The results significantly improve both the level and distributional fairness of TECO's rates and are shown in Tables KRR-4 and KRR-5, and reflect elimination of the MDS approach on a revenue-neutral basis.

Table KRR-4: Current and Proposed Residential Rates with MDS Removed and 7% Reduction Applied to Volumetric Rates to Estimate Impact of 9.50% ROE

CURRENT AND PROPOSED RESIDENTIAL (RS) RATES				
RATE	TECO CURRENT	TECO PROPOSED	DIFFERENCE PROPOSED ($)	DIFFERENCE PROPOSED (%)
Fixed Customer Charge (per Customer/Day)	$ 0.71	$ 1.07	$ 0.36	51%
Fixed Customer Charge (per Customer/Month)	$ 21.60	$ 32.55	$ 10.95	51%
Energy & Demand Rate 0-1000 kWh (Cents/kWh)	6.65	7.49	$ 0.84	13%
Energy & Demand Rate >1000 kWh (Cents/kWh)	7.80	8.49	$ 0.69	9%

RATE	TECO PROPOSED	RÁBAGO PROPOSED	DIFFERENCE PROPOSED ($)	DIFFERENCE PROPOSED (%)
Fixed Customer Charge (per Customer/Day)	$ 1.07	$ 0.43	$ (0.64)	-90%
Fixed Customer Charge (per Customer/Month)	$ 32.55	$ 13.08	$ (19.47)	-90%
Energy & Demand Rate 0-1000 kWh (Cents/kWh)	7.49	8.59	1.10	17%
Energy & Demand Rate >1000 kWh (Cents/kWh)	8.49	9.52	1.03	13%

Table KRR-5: Teco and Rábago Proposed Changes to Current Bills and to Effective Total Cents Per Kwh as Various Usage Levels

	PROPOSED CHANGES TO CURRENT BILLS				PROPOSED CHANGES IN TOTAL CENTS/KWH		
	TECO		RÁBAGO				
kWh/Month	DOLLARS	PERCENT	DOLLARS	PERCENT	PRESENT	TECO PROPOSED	RÁBAGO PROPOSED
100	$ 11.71	34%	$ (7.69)	-23%	$ 34.01	$ 45.72	$ 26.32
250	$ 12.67	24%	$ (4.91)	-9%	$ 20.90	$ 25.97	$ 18.94
500	$ 14.27	17%	$ (0.27)	0%	$ 16.53	$ 19.39	$ 16.48
750	$ 15.86	14%	$ 4.36	4%	$ 15.08	$ 17.19	$ 15.66
1000	$ 17.46	12%	$ 8.99	6%	$ 14.35	$ 16.09	$ 15.25
1165	$ 18.25	11%	$ 11.68	7%	$ 14.35	$ 15.92	$ 15.35
1250	$ 18.66	10%	$ 13.06	7%	$ 14.35	$ 15.85	$ 15.40
1500	$ 19.87	9%	$ 17.12	8%	$ 14.36	$ 15.68	$ 15.50
2000	$ 22.28	8%	$ 25.25	9%	$ 14.36	$ 15.47	$ 15.62
3000	$ 27.10	6%	$ 41.51	10%	$ 14.36	$ 15.27	$ 15.75
5000	$ 36.74	5%	$ 74.02	10%	$ 14.37	$ 15.10	$ 15.85

VI. TECO'S USE OF A 4 CP METHOD TO ALLOCATE RETAIL COSTS UNFAIRLY AND UNREASONABLY BURDENS RESIDENTIAL CUSTOMERS

Q. What impact does TECO implementation of a 4 CP allocation method for production and demand-related retail costs have on residential customer rates and affordability?

A. TECO's use of the 4 CP allocation method unjustly increases the share of production and demand-related retail costs that residential customers must bear relative to other rate classes when compared to the 12 CP or 12 CP 1/13th AD methods. TECO uses the 4 CP method because it agreed to do so in the settlement of its 2021 rate increase application.[55] Along with the use of the MDS method for classifying demand-related costs as customer costs, the use of the 4 CP allocation method adds about $71 million in costs to residential customers that they would not be required to pay under a 12 CP 1/13 AD method without the use of the MDS customer cost method.[56]

Q. How does the cost allocation method change class revenue burdens?

A. The increased burden related to the cost allocation method is a product of two key factors—the relative contribution to total demand that a class places on the retail system, and the number and times when those contributions are measured. All things being equal, customers with higher relative demand—"peakier" demand—will be assigned a higher share of costs than customers with flatter demand patterns when fewer dates that align with overall system peak ("coincident peak") are sampled. Thus, with residential customers generating a larger share of peak demand in general, when load studies focus on a small number of months with the highest demand—as under a more narrowly focused 1 CP or 4 CP approach—more costs are allocated to residential customers. Likewise, if the highest peak days in each of the twelve months in the year are sampled, larger customers will be assigned more costs based on their consistently high usage across the span of a year. Average demand adjustments can also be used to reflect non-coincident peak demand created by a class as a whole. This is the "zero sum game" of cost allocation, and under TECO's management, residential customers lose.

Q. What factors are considered when deciding which allocation method to use?

A. Although arguments and justifications about which cost allocation method to use are often couched in broad assertions about which method better reflects cost causation, the decision of how to slice the pie of total revenue requirements often devolves to a contest of regulatory political power played out in confidential settlement negotiations. Very large customers with the ability to fully participate in rate proceedings represented by expensive consultants often do better than residential consumer advocates with limited budgets. It is also true that because the number of residential customers and small business customers vastly exceeds the numbers of customers in other classes, assignment of revenue requirement increases to small customers can result in smaller per-unit or per-bill increases relative to other customer classes. Additionally, under a somewhat perverse and certainly unjust theory of inverse elasticity, monopoly utilities often find convincing the argument that excess costs should be assigned to customers with the least opportunity to do anything but pay the charges.[57]

Q. How does TECO rationalize its participation in the 2021 settlement that required it to apply a 4 CP methodology and full implement an MDS approach for assigning demand-related distribution costs to residential customers?

A. Consistent with its almost complete lack of focus on customer affordability, TECO seems quite comfortable with regressive cost allocation and rate design methods imposing increasing shares of the burden of its profit seeking on residential and, to a lesser degree, small business customers. Oddly, TECO asserts that the 4 CP method is more appropriate today because TECO is increasing the solar fraction in its generation fleet,[58] as compared to what have been historically called "baseload" generation like coal plants and “shoulder” combined cycle gas plants. This argument does not serve as a reasonable justification for the use of the 4 CP method. First, it is an argument about the performance nature of generators, not the cost causation characteristics of customers. Second, TECO is using a 4 CP method that weighs 25% of allocated costs based on a January coincident peak—which has little or no relationship to solar production costs. Third, it ignores the fact that low-use, low-income customers often have particularly flat load shapes, especially in the South. Fourth, as TECO admits, the firm capacity of the solar it is adding continues to diminish due to the non-solar peak shift caused by the addition of more solar, as will the amount of energy the solar plants add to the non-solar peak. The residual non-solar peak is what TECO will have to plan on for non-solar generation and what is used to calculate the reserve margin for planning purposes. Solar additions further in the future are estimated to provide smaller contributions to peak firm capacity.[59] Fifth, even in 2021, when this shift would have been smaller, TECO proposed to allocate 50% of solar production to energy based on this shift, a shift that has only accelerated since that time.

Q. What do you recommend?

A. In my opinion, the best measure for which cost allocation method to use is which best serves and promotes the public interest. Under TECO’s rates and spending proposals, with the energy burden information that I have presented in this testimony, and in light of general economic conditions, the better approach for TECO would be use of a 12 CP allocation, perhaps with an average demand modifier to address residential contributions to coincident peak demand. Given that solar production costs are driving so much of capital expenditures, and that solar, at best, contributes 50% to some peaks, I recommend using a 12 CP & 50% AD methodology without MDS, as reflected in Exhibit KRR-3 and Exhibit KRR-4 (reflecting my recommended 9.5% ROE with no other additional changes, although other costs should be disallowed as as discussed below), and I recommend the Commission direct TECO to adjust rates accordingly, such as I have done in Exhibit KRR-5. Each of these exhibits was developed by making minimal changes to inputs, consistent with my testimony, to TECO's intact MFR models. At a minimum, if 12 CP & 50% AD is not accepted by the Commission, I recommend that the Commission direct TECO to use their 12 CP & 1/13 AD cost of service study, without the use of the MDS method, and to adjust rates accordingly.

VII. <u>TECO PROPOSES ADDITIONAL UNJUSTIFIED AND UNREASONABLE SPENDING THAT THE COMMISSION SHOULD DENY IN THIS PROCEEDING</u>

Q. What other TECO spending proposals merit the Commission's review and disapproval?

A. The Commission should act to reign in TECO's proposed spending spree in order to help ensure customers can afford essential electric service. I point out several issues where Commission action is appropriate, though my silence on any particular issue should not be considered support for any TECO proposal. The issues that I propose to call the Commission's attention to include the following:

- The Commission should deny any rate recovery of employee incentive compensation program costs until TECO submits a revised employee incentive compensation plan. TECO's current proposal is to charge customers some $33 million for short- and long-term incentive compensation payments that encourage rate and cost increases to grow net income and that fail to directly address customer affordability at all.[60] The Commission should require TECO to submit a plan that includes shareholder direct "below the line" funding of at least 50% of the incentive compensation program budget and that reflects two major changes: (1) A required performance metric that addresses maintaining and improving customer affordability, especially among residential customer with income levels at or below 400% of the Federal poverty level. In particular, this metric should be addressed with permanent or long-lived actions that do not merely require other customers to pay low-income customer bills. (2) The revision of any earnings-based performance metrics to ensure that only earnings improvements that reflect measurable customer benefits qualify for inclusion in any incentive compensation program.

- The Commission should deny TECO's proposals to increase service charges for service connection and reconnection above the Florida-wide rate of inflation in the previous calendar year. Electric service is too important and too necessary for survival for TECO to charge $168 per customer for a new service connection, and its proposed fees are out of step with those for other utilities in Florida or operated by Emera.[61] I recommend that these charges be reduced by 80%.
- The Commission should disapprove any capital spending project of $1,000,000 or more that is not supported by a comprehensive, objective, transparent, and documented BCA. TECO's current approach to developing major capital projects relies solely on management discretion

and a cumulative present value of revenue requirements ("CPVRR") approach that lacks transparency and objectivity, and that ignores cost-effective alternatives that may offer better, more affordable outcomes.[62] Given the heavy incentive compensation weighting TECO proposes for increasing net income,[63] there is strong management incentive to advance projects that lower CPVRR by the least amount possible. Without BCAs to analyze alternatives and inform consideration of proposals submitted for approval, the Commission has no way of knowing whether TECO spending proposals will result in rates that are fair, just, and reasonable.

- The Commission should disallow any spending on the Polk fuel oil project which would increase dependence on a dirty form of fossil fuel and has not been demonstrated to be cost-effective through completion of a BCA.
- The Commission should disapprove any rate recovery for the so-called South Tampa Resilience Project to be sited at McDill Air Force Base. The $160 million project[64] has several major flaws that must be addressed before the Commission allows it to possibly move forward. First, the project lacks the support of a BCA to ensure that it is the most cost-effective option for obtaining the resilience benefits it is designed to obtain. Second, the project would add new highly-pollution fossil fuel generation to the TECO system mix in the form of reciprocating gas engines. Third, the proposal will receive no direct funding support from the U.S. Department of Defense or the Federal government, and only a 33-year cost-free lease for the land.[65] I find it incredible and unconscionable that TECO would propose a deal in which its hard-working, tax paying customers must subsidize the U.S. government with payments for such a

project.

- The Commission should disapprove any rate recovery for new building construction until TECO produces a comprehensive BCA that fully considers alternatives to new building construction.
- The Commission should disapprove most, if not all, of the rate recovery for the so-called transmission and distribution reliability improvements supported by witnesses Whitworth and Lukcic as unnecessary gold-plating of the system that is destined for quick obsolescence (including a private LTE network for the utility).

VIII. RECOMMENDATIONS

Q. Please reprise your recommendations to the Commission in this proceeding.

A. In this testimony, I present a number of recommendations designed to reduce the outsized electric bills and energy burdens faced by TECO's residential customers. These recommendations include:

- Ending TECO's reliance on the Minimum Distribution System ("MDS") method of classifying demand-related costs as customer costs to be recovered through fixed customer charges.
- Reducing TECO's ROE to 9.50%.
- Disallowing use of the 4 Coincident Peak ("CP") method for cost allocation and replacing it with a 12CP & 50% AD methodology.
- Reducing proposed increases in TECO connection and reconnection service charges by 80%.
- Eliminating TECO's proposed Polk fuel oil project.
- Disallowing TECO's South Tampa resilience project absent significant

project funding from the Federal government and/or the U.S. Department of Defense.

- Disallowing further spending on new building construction until TECO produces a comprehensive BCA that fully considers alternatives to new building construction.
- Disallowing all costs related to incentive compensation absent new performance metrics that directly measure improvements in customer affordability, especially among low-income customers, and the removal of incentives for meeting Emera earnings-per-share objectives through methods that worsen affordability.
- Requiring TECO to BCAs to support all requests for capital spending projects for $1 million or more, and disapproval of any transmission and distribution system projects until TECO applies a standardized BCA approach to each project.

Q. Does this conclude your direct testimony?

A. Yes.

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[1] TECO Resp. to FL Rising/LULAC INT 103.

[2] TECO Resp. to FL Rising/LULAC RFA 1.

[3] TECO Resp. to FL Rising/LULAC INT 104.

[4] *Id.*

[5] TECO Resp. to FL Rising/LULAC INT 101.

[6] U.S. Energy Info. Admin., EIA-861 M Sales and Revenue Data 2023, available at: https://www.eia.gov/electricity/data/eia861m/archive/xls/sales_ult_cust_2023.xlsx.

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[7] U.S. Energy Info. Admin., RECS State Data on Fuel Consumption 2020, https://www.eia.gov/consumption/residential/data/2020/state/pdf/ce2.1.st.pdf (last visited June 4, 2024). Calculated as 47.7 MMBtu * 293.07107 MMBtu/kWh = 1,165 kWh.

[8] *See* U.S. Energy Info. Admin., RECS Data 2020, Tables CE1.1-1.5, https://www.eia.gov/consumption/residential/data/2020/index.php?view=consumption (last visited June 4, 2024).

[9] Diana Hernández, *Understanding 'Energy Insecurity' and Why It Matters to Health,* 167 Soc. Sci. Med. 1, 2 (Oct. 2016) https://www.ncbi.nlm.nih.gov/pmc/articles/PMC5114037/.

[10] *Id.*

[11] U.S. Dept. of Energy, *Low-Income Energy Affordability Data Tool,* Office of Energy Efficiency and Renewable Energy, https://www.energy.gov/scep/slsc/lead-tool (last visited June 4, 2024).

[12] Federal Poverty Level data, which applies to Florida, is available from the U.S. Department of Health and Human Services. For 2020 levels, see https://aspe.hhs.gov/topics/poverty-economic-mobility/poverty-guidelines/prior-hhs-poverty-guidelines-federal-register-references/2020-poverty-guidelines. For 2024 levels, see https://aspe.hhs.gov/topics/poverty-economic-mobility/poverty-guidelines.

[13] Fla. Dept. of Heath, *Individuals below Poverty Level (Census ACS),* Florida Health Charts, https://www.flhealthcharts.gov/ChartsDashboards/rdPage.aspx?rdReport=NonVitalInd.Dataviewer&cid=294 (last visited June 4, 2024).

[14] TECO Resp. to FL Rising/LULAC INT 110–112.

[15] TECO witness Archie Collins direct testimony ("Collins Direct").

[16] *Id.* at 5.

[17] *Id.* at 23.

[18] *Id.* at 19–20.

[19] Source: TECO Resp. to OPC POD 1-1, folder "MFR E", file "(BS 197)2025 Proposed Rates MFR.xlsx"

[20] *Id.*

[21] TECO witness Jordan Williams direct testimony ("Williams Direct") at 14, et seq.

C25-2577

[22] TECO Resp. to FL Rising/LULAC INT 60.

[23] TECO Resp. to FL Rising/LULAC INT 59.

[24] TECO Resp. to FL Rising/LULAC INT 62.

[25] *Id.*

[26] TECO Resp. to FL Rising/LULAC INT 55.

[27] TECO Resp. to FL Rising/LULAC INT 62, 64, 65.

[28] Nat'l Ass'n of Regul. Utility Comm'rs ("NARUC"), Electric Utility Cost Allocation Manual at ii (Jan. 1992) ("The [Manual's] writing style should be non-judgmental; not advocating any one particular method but trying to include all currently used methods with pros and cons.").

[29] TECO Resp. to FL Rising/LULAC INT 64, 65.

[30] TECO Resp. to FL Rising/LULAC INT 63.

[31] James C. Bonbright, Principles of Public Utility Rates at 347 (1961), https://www.raponline.org/wp-content/uploads/2023/09/powellgoldstein-bonbright-principlesofpublicutilityrates-1960-10-10.pdf.

[32] Jim Lazar & Wilson Gonzalez, Smart Rate Design for a Smart Future at 6, 36, Regulatory Assistance Project (July 2015), https://www.raponline.org/wp-content/uploads/2023/09/rap-lazar-gonzalez-smart-rate-design-july2015.pdf.

[33] Bonbright, *supra* n.31 at 347.

[34] *See* Williams Direct at 14, et seq.

[35] Bonbright, Principles of Public Utility Rates, *supra* n.31 at 347–49.

[36] Jim Lazar, Paul Chernick, & William Marcus, Electric Cost Allocation for a New Era: A Manual, Regulatory Assistance Project (Jan. 2020), https://www.raponline.org/wp-content/uploads/2023/09/rap-lazar-chernick-marcus-lebel-electric-cost-allocation-new-era-2020-january.pdf.

[37] *Id.* at 146–148 (citations omitted).

[38] *Id.*

[39] Frederick Weston, Charging for Distribution Utility Services: Issues in Rate Design at 30 (Dec. 2000) (citing the "basic customer" method as the method in use in more than 30 states), https://www.raponline.org/wp-content/uploads/2023/09/rap-weston-chargingfordistributionutilityservices-2000-12.pdf.

[40] Lazar, Chernick, & Marcus, *supra* n.36 at 145, n.141–48 and accompanying text.

[41] As such, there is no validity in rate making by alliteration, as proposed in the so-called "straight fixed-variable method" which promotes fixed charges for fixed costs.

[42] Williams Direct at 14.

[43] TECO Resp. to FL Rising/LULAC INT 78.

[44] *Id.*

[45] TECO Petition for Rate Increase at 6, ¶ 15.

[46] TECO witness Jeff Chronister direct testimony ("Chronister Direct") at 4.

[47] TECO witness Dylan W. D'Ascendis direct testimony ("D'Ascendis Direct").

[48] *Id.*

[49] Collins Direct at 31.

[50] Edison Electric Institute ("EEI"), *Electric Company Industry Financial Data and Analysis – Rate Review Data* (2023 Q4), https://www.eei.org/issues-and-policy/finance-and-tax.

[51] *Id.*

[52] TECO Resp. to FL Rising/LULAC INT 103.

[53] Christopher Rugaber, *Fed Powell Suggests Taming Inflation Will Take Longer Than Expected,* PBS NewsHour (May 1, 2024), https://www.pbs.org/newshour/economy/watch-live-fed-chair-powell-holds-news-conference-following-interest-rate-meeting.

[54] As of 2024, TECO is 88% dependent on fossil fuels for generation, with the remainder coming from utility-scale solar generation. Collins Direct at 18.

[55] TECO Resp. to FL Rising/LULAC INT 53.

[56] *Id.* at 53.d.

[57] The Wikipedia entry related to the so-called "Ramsey Problem" explains this approach as follows: "The Ramsey problem, or Ramsey pricing, or Ramsey–Boiteux pricing, is a second-best policy problem concerning what prices a public monopoly should charge for the various products it sells in order to maximize social welfare (the sum of producer and consumer surplus) while earning enough revenue to cover its fixed costs. Under Ramsey pricing, the price markup over marginal cost is inverse to the price elasticity of demand and the price elasticity of supply: the more elastic the product's demand or supply, the smaller the markup." Wikipedia, *Ramsey Problem*, https://en.wikipedia.org/wiki/Ramsey_problem (last visted June 4, 2024).

[58] TECO Resp. to FL Rising/LULAC INT 4.a.

[59] *See* TECO TECO Resp. to FL Rising/LULAC INT 8.

[60] *See* TECO witness Marian Cacciatorre direct testimony ("Cacciatorre Direct"); TECO Resp. to OPC POD 1-30 (BS pages 13178–13249); TECO Resp. to FL Rising/LULAC INT 96–99.

[61] *See* TECO Resp. to FL Rising/LULAC INT 115–17.

[62] TECO witness Jose Aponte direct testimony ("Aponte Direct") at 7–8; TECO Resp. to FL Rising/LULAC INT 95.

[63] TECO Resp. to OPC POD 1-30 (BS pages 13178–13249). TECO typically weights net income goal achievement at 35% of the total incentive compensation package.

[64] TECO witness Carlos Aldazabal direct testimony ("Aldazabal Direct") at 46–50.

[65] TECO Resp. to FIPUG INT 1.

BY MR. MARSHALL:

Q Mr. Rabago, did you prepare a summary of your testimony?

A Yes, I have.

Q Would you please go ahead and give us your summary?

A Yes, I will.

My name is Karl R. Rabago. I am the principal and the sole employee of Rabago Energy, as I already stated. My direct testimony summarizes my background in education, and attached exhibits include a detailed resume and a table of prior testimonies.

My testimony is focused on TECO's proposed spending and resulting proposed rates. The starting point for my testimony is the fact that TECO residential customers already pay some of the highest electric bills in the nation.

Of import to me, and to Florida Rising and the League of United Latin American Citizens, as well as Earthjustice, is how these high bills, which TECO proposes to increase dramatically, will impact customers with high energy burdens.

TECO's holding company, Emera, a foreign corporation, already burdens TECO customers to a greater degree than customers of other utility operating companies that it owns. And again, it seeks to worsen these impacts on its Florida customers.

In all, TECO and Emera propose to tax their Florida customers with an additional 555 million in rates over the years 2025 through 2027, starting with about two-thirds of that amount in 2025 alone. I understand that there have been some small adjustments to those numbers filed recently.

TECO uses a multipronged strategy in its efforts to impose unnecessary and unreasonable economic burdens on Florida customers. My testimony describes how each of these efforts are unreasonable and should be rejected by the Commission.

The first place to start is with my Table KRR-1, which shows how TECO and Emera have -- and Emera have been on a feeding frenzy, growing earnings from Florida customers at a rate more than five times the growth of customer count, and eight times the rate of energy sales growth over the period 2018 through 2023.

It's no surprise that TECO residential bills are now among the highest among major Florida utilities, nearly 40 percent higher than the national average, and higher than those in any state except Hawaii and Connecticut. Under competitive market conditions, which regulation is supposed to replicate for monopoly utilities, TECO would not get away with this. I urge the Commission to ensure that TECO and Emera don't get away with it under Public Service Commission oversight.

Specifically, I recommend that the Commission order TECO to, first, end reliance on minimum distribution system method for classifying demand-related costs as customer costs. This is essential to providing just and reasonable rates, and to honoring the principle of cost causation.

Next, operate with an allowed return on equity of 9.5 percent, which, although still high, is more in line with actual market risk and the access to capital needs that TECO has.

Third, more fairly allocate costs with a 12 Coincident Peak method.

Next, reduce service charges for connection and reconnection. Eliminate the Polk Fuel Oil Project. Disallow spending on the South Tampa Resilience Project until the federal government pays most, if not all, of the cost of a project designed primarily to serve the federal government.

Disallow spending for any new building construction until TECO fully and fairly analyzes the benefits of the proposed projects and reasonable alternatives.

Disallow all incentive compensation, especially for compensation tied to afford it -- sorry -- tied to earnings -- excuse me. Disallow all incentive compensation, especially for compensation tied to affordability worsening earnings per share targets until TECO and Emera establish performance metrics that directly measure customer affordability, especially among low income customers.

And finally, develop and secure Commission approval for a new objective, comprehensive benefit cost framework that must be used for any and all major capital projects.

In support of my recommendations, I make several key points.

First, in high-use regions like Florida, ensuring just and reasonable rates means taking into account customer bills. With average monthly usage of 1,155 kilowatt hours per month, 15 percent higher than the conventional 1,000 kilowatt hours, high rates like those proposed by TECO mean extraordinary bills, about $184 per customer per average month.

For millions of low-income customers in Florida, and for the nearly 13 percent of households in Hillsborough County alone that are in poverty, high bills mean high energy burdens measured as the percent of household incomes that goes to utilities and other energy providers. High bills also mean energy insecurity.

Second, I point out that TECO knows little or nothing about its low-income customers except what it wants to charge them. It does not seek to understand household energy burdens or how rates will impact them. The performance of TECO and its leadership is not measured against affordability for customers, though there are performance metrics for earnings per share.

Third, I demonstrate in Table KRR-3 that TECO seeks to worsen the impact on low users of electricity, who are often low-income customers, with regressive rate increases.

Fourth, my testimony addresses the regressive, unjust and unreasonable approach TECO uses to develop its proposed fixed customer charges through the minimum distribution system. I point out that one of the most egregious impacts of the TECO approach is that it also sends perverse economic signals to TECO, rewarding the utility for excessive spending in order to boost guaranteed revenues.

And I should sum up by saying, there is a couple of other points, but I have run out of time. I will just close by saying, TECO lacks internal discipline to ensure that it provides electric service at just and reasonable rates. The result is economic injustice and unaffordable rates for residential customers. This is the moment for this commission to rein in excessive spending and unjust rates proposed by TECO and its owner, Emera, in this proceeding.

Thank you.

Q Thank you.

MR. MARSHALL: We tender the witness for cross-examination.

CHAIRMAN LA ROSA: Thank you.

OPC.

MR. REHWINKEL: No questions.

CHAIRMAN LA ROSA: FIPUG.

MR. MOYLE: We have some questions.

CHAIRMAN LA ROSA: Sure.

EXAMINATION

BY MR. MOYLE:

Q Good morning. How are you?

A Morning. Good. Thank you.

Q Good. I am Jon Moyle. We met last night in the hall, and I represent the Florida Industrial Power Users Group.

I want, if I could, to just direct you to a portion of your testimony. We have this new system we

are doing here, it's working well, where I just call out a number, and it appears on your computer screen and appears on the big screen. So I would like to call out C25-2527, which is a portion of your testimony. If you have a hard copy, it's page three.

CHAIRMAN LA ROSA: You will see it there in your screen.

BY MR. MOYLE:

Q -- and I am looking at line 4.

A I see it.

Q So in terms of what you do now, your career, I mean, you provide testimony on behalf of your clients today, isn't that right? I mean, you are an expert witness, and you appear frequently? If you can go yes, no, and if --

A About half of my work is related to expert witness testimony. Yes.

Q Okay. And you had an exhibit that listed where you have testified and then what topics you have covered, correct?

A Since I started Rabago Energy, yes.

Q Yes. And the line that caught my eye in this testimony up here is on the line four, and I will just pick it up and read it, but it says -- the sentence goes on, you pick up, you say you have made a career of

advancing regulatory and market opportunities for competitive alternatives to monopoly control of essential services businesses, is that right?

A I have done that. Yes.

Q Yeah. And, you know, today you are testifying -- or you just went through your summary about a lot of issues. Isn't it fair to say that in the course of your testimony history, that you do not focus predominantly, while you talk about it, but you don't focus predominantly on cost of service and rate design issues?

A No, that's not fair.

Q So if we went and looked in the resume that you have, would you accurately reflect when you have talked about cost of service design issues in those testimonies?

A I am sorry, you just changed your question from cost of service and rate design issues to cost of service design issues.

So a substantial amount of my testimony has been related to various kinds of rate design issues, perhaps not within the context of full cost of service studies. So I am just wanting to be very clear.

Q Well, why don't you answer it within the context of the cost of service studies.

A Okay. So it is -- I have not counted, but I am sure that substantially less than half of my testimony has specifically gone through full cost of service studies and provided them, or critiqued them in their entirety.

Q Right.

A And that's of the 170 or so pieces of testimony that I listed in that document.

Q Right. You served on the Texas Utilities Commission from 1992 to 1995, is that right?

A Yes. The Texas Public Utility, for some reason, they use a singular, Commission.

Q Okay. And it's the equivalent to our Florida Public Service Commission, correct?

A It is and still different, as everything in Texas is.

Q I would like to call up Document F-4-1, please.

A All right. I am seeing it on my screen now.

Q Sure. Could you identify this document, please?

A Sorry, say again.

Q Could you identify it?

A Oh, yes. This appears to be a -- some kind of printout of a examiner's report in a general rate case involving Texas New Mexico Power Company, and I was sitting on the Texas PUC at the time.

Q And if we could go to F-4-207.

A Can you do that? Okay. Yeah.

Q And I know you probably --

A I can it now.

Q You say in your testimony you had a lot of orders that you handled and dealt with when you were part of that utility, so I thought it would be helpful just to give you this document.

And would you please just read into the record the paragraphs 178 to 180 that's before you?

A Okay. Let me roll up just a little bit so I can see it all. All right. These are order paragraphs from the hearing examiner's report, paragraph 179: TNMP -- which is the acronym for Texas New Mexico Power -- TNMP's allocation of production plant expense using the 4CP/A&E allocator is reasonable because the 4CP/A&E allocator accurately recognizes energy and demand requirements of each customer class, the average of the four summer months reflecting demand requirements, and provides stability compared to the use of a single peak, and the 4CP/A&E allocator considers the cost responsibility of off-peak users and on-peak users.

Paragraph 180: It is reasonable to allocate the transmission facility using the 4CP/A&E allocator because the transmission facility is an extension of production plant.

Q The Commission adopted the hearing officer's report with respect to these provisions, isn't that correct?

A I am sorry, could you say that again?

Q Your commission adopted this part of the report, isn't that --

A Yes, we issued this, and issued an order consistent with it. Yes.

Q If I can refer you to F-4-294. And that will pop up another document. All right. This --

A I have it in front of me with some highlighted text like yours.

Q Okay. Good.

Could you just identify the document, if you would, please?

A Yeah. So this is an extract of the then applicable, I believe -- actually, I am not sure what the vintage is on this, but these are Texas substantive rules. Maybe they are current. Let me see. I actually don't know. Wait a minute. Let me look at the bottom and see if there is any -- yeah, these are effective December 20th, 2022, so this -- these are current substantive rules at the Texas, you know, under the Texas Administrative Code. And these, in particular, apply to transmission service rates, Section 25.192.

Q Could you just read into the record the first highlighted portion under the first paragraph there, B1?

A Yes.

So section 25.192 says: In discussing charges for transmission service within ERCOT -- that's the Electric Reliability Council of Texas -- a -- and it excludes storage entities.

Number -- paragraph one: A TSP's transmission rate -- sorry, that's a transmission service provider -- we and our acronyms -- A TSP's transmission rate shall be calculated as its commission-approved transmission cost of service divided by the average ERCOT coincident peak demand for the months of June, July, August and September (4CP), excluding the portion of coincident peak demand attributable to wholesale storage load.

And did you want the second part as well?

Q No, that's fine.

A Okay.

Q I would like to move you through to F4-299.

A Oh, formula.

Q And I will tell you my understanding of this, and you can tell me if you understand it as well.

I don't understand the formula of the math, but my understanding about how this works in Texas is that there is a formula that's done to calculate the 4CP approach. It's done annually. And then that information is published and used for the CP -- 4CP approach. Does that comply with your understanding?

A Yes.

Q That's --

A That is my understanding, and this is a formulaic representation of the calculation which ERCOT conducts in order to allocate its costs among all those that take load off the ERCOT system.

Q Okay. And then the last document that I want to show you is F-4300. This document -- I will describe it to you, and I will just ask you if it makes sense to you, given your testimony that this is the ERCOT web page for the 4CP approach and the calculations that they do annually, and embedded in there the calculations that have been done from 1996 to 2019. Does that sound right to you?

A Yes. Embedded is a link that takes you to those calculations that are published by ERCOT.

Q All right. And are you aware, there was another document -- we ran into some issues -- but that it's still in place today, that these calculations are

still done, and the 4CP is still in place today?

A Yeah. The -- my only clarification would be that your still-in-place statement assumes a continuity that does not exactly match history. We didn't have the full ERCOT nodal market back when I signed the TNP order. It -- the nodal market was fully established subsequently to that, and -- so there have been other changes.

But ERCOT and Texas use the 4CP method for allocating these costs. You know, it's the same calculation approach, but there is a whole different context in place in Texas now, since deregulation and the nodal market.

Q Yeah.

MR. MARSHALL: Mr. Chairman, before we move on, I just need clarification on this exhibit to see whether we have an objection to it.

I just want to make sure Mr. Moyle isn't trying to include it as part of the exhibit into the record the data that's -- that you would get through the link that's on this page.

CHAIRMAN LA ROSA: Yeah, let's get clarification.

MR. MOYLE: I listed it, I tried to do it, and it has piles and piles and piles and reams of information. I was working with your staff. It was difficult downloading, so I made a judgment that really what I want this exhibit for is to show that this 4CP has been in use for the period of time that's reflected in the link. I don't need the data, so that's the clarification.

MR. MARSHALL: Thank you.

CHAIRMAN LA ROSA: Okay.

BY MR. MOYLE:

Q Do you agree in general that a class cost of service study should follow the principle of cost causation, and that is that the costs should be allocated to customer classes that cause the utility to incur them?

A As I --

Q If you can give --

A Yes, I agree.

Q Are you aware that this commission approved the 4CP with MDS in TECO's last rate case?

A I understand that was a condition of the settlement in 2021.

Q So that would be yes also?

A I believe so. I think the statement that I remember reading was, would support and would not -- or would not oppose.

Q Do you know how settlement agreements get approved in Florida?

A Do I?

Q Do you have any familiarity with how settlement agreements get approved in Florida?

A Not specifically. I assume they are put forth by the parties and adopted by the Commission and entered as the official decision of the Commission.

Q Okay. The Texas Commission did not approve a 4CP method for allocating production plant while you were a Texas Commissioner, correct?

A They did not, you are saying?

Q They did not.

A So the TNMP order is about the 4CP/A&E.

Q I am sorry. 12CP.

A Oh, the 12CP?

Q Yeah. I misspoke. Let me just start over. That the Texas Commission, when you were there, that they did not ever approve a 12CP --

A Yeah.

Q -- method for allocating production plant, correct?

A I really do not remember. If you told me there is no such order, I would have to assume you are telling the truth, subject to check.

Q In general, are you aware that the Texas Public Utilities Commission has consistently rejected cost allocation methodologies, or methods that allocate a portion of production plant on energy?

A I am not aware of energy-based allocations being used in Texas, but I just don't -- I don't know that they have rejected or refused to adopt.

Q And you haven't provided any analysis of TECO's system load characteristics in supporting the 12CP portion of your testimony, correct?

A I have not.

MR. MOYLE: Okay. Those are all the questions I have.

CHAIRMAN LA ROSA: Great.

FEA.

CAPTAIN GEORGE: No questions. Thank you.

CHAIRMAN LA ROSA: FRF.

MR. LAVIA: No question. Thanks.

CHAIRMAN LA ROSA: Walmart.

MS. EATON: No questions.

CHAIRMAN LA ROSA: TECO.

MR. WAHLEN: No questions.

CHAIRMAN LA ROSA: Staff.

MR. SPARKS: No questions. Thank you.

CHAIRMAN LA ROSA: Commissioners, do we have questions?

Commissioner Fay, you are recognized.

COMMISSIONER FAY: Thank you, Mr. Chairman. Just one quick question.

Mr. Rabago, good to see you again.

THE WITNESS: Nice to see you.

COMMISSIONER FAY: You referenced the residential bills and some EIA data in your testimony, do you recall that?

THE WITNESS: Yes, sir.

COMMISSIONER FAY: Okay. When you are reviewing that for purposes of arguing the rates and the affordability component, do you do a comparable, I guess, to other states that, for example, have high gas utilities in addition to their electric utilities, or would have separate bills comparably, or does maybe EIA do that within their data?

THE WITNESS: I have not done a sorting of electric bills using the table, I think it's Table 5 or Table 6, data from EIA that excludes, you know, separates into bins, you know, dual fuel versus single fuel type usage.

So, for example, we know Hawaii ends up with high -- they have very high rates, but they also have higher bills because they are not dual fuel. But I haven't sorted them out, so they would -- if, if we were doing dual fuel, you would move them off the top kind of and put them in the electric only category.

COMMISSIONER FAY: Gotcha. And I guess the warmer states that utilize less gas for heating, like, they would --

THE WITNESS: Right.

COMMISSIONER FAY: -- they would typically, maybe not all, but typically be separate?

THE WITNESS: Right.

COMMISSIONER FAY: Okay.

THE WITNESS: Right. That's right. The dual fuel utilities will have lower electricity consumption over the course of a year, and their -- and using the annual data like I look at, because customers are maybe relying on methane gas for winter heating, and so they would end up ranking lower in total average consumption.

COMMISSIONER FAY: Gotcha. Okay.

And then just one quick follow-up, Mr. Chairman.

That same data, do you know, does it -- I guess, does it update -- we have had some testimony about pending rate cases, and that sort of thing. Does it update for, I guess, rate cases? Is it -- it's quarterly or monthly? Or how would you do comparables, in other words, if you had a state that had a pending utility and one that didn't?

THE WITNESS: If -- yeah, not be too cute, but if I was doing it, I would tell the -- make the utilities tell me. But what we all -- what we have is, this is FERC Form 1 data.

So the best calculation that we can get on the public data available that is comparable, and that's comparable across the United States, or that could be sorted as you describe, is the Form 1 data, which gives you total residential revenues, for example, and total residential sales, from which you can do that division. And then you have total residential revenues, and you divide, you know, you can see what those revenues are to come -- by average monthly consumption for customers to come out with an average monthly bill.

COMMISSIONER FAY: Okay. Great. Yeah, because it breaks it down for, I guess, generalized classes, where you can review residential, commercial, industrial and then you --

THE WITNESS: Yes.

COMMISSIONER FAY: Yeah, go ahead.
THE WITNESS: Yes, sir. You can -- you can -- they have on and off system sales. They have residential, commercial and industrial. They may have some other categories in there. And so you can just sort into the Excel and choose the categories you want. I focused on residential sales, revenues and customer count.
COMMISSIONER FAY: Great. Okay. That's helpful.
I am trying to understand how, as a commission, we -- and as a former commissioner, you can appreciate this -- how we weigh data that, you know, is difficult to align because you have these pending utilities and changes in states that don't all occur at the same time. I imagine maybe January 1, or some other dates, are more aligned than others. But when you are in the middle of the year, I presume it's difficult to kind of compare them.
THE WITNESS: It is a tool for comparison. Your site plans, for example, provide a rich source of data that, you know, tells us a lot about the customer classes, and demand, and energy sales, and all that stuff. But if you want to try to plant it

-- place it in context, say, with Alabama, or, you know, or with Connecticut, the best tool we have is the EIA data that's derived from FERC Form 1 data and other sources.

COMMISSIONER FAY: Okay. Great. Thank you.

THE WITNESS: Yes, sir.

CHAIRMAN LA ROSA: Further questions?

Seeing none, let's send it back to Florida Rising/LULAC for redirect.

MR. MARSHALL: Thank you, Mr. Chairman.

FURTHER EXAMINATION

BY MR. MARSHALL:

Q Mr. Moyle asked you about a -- the cost of service methodology that was adopted in a Texas case, do you recall --

A Right.

Q -- that line of questions?

Do you believe that cost of service methodology should be applied to TECO?

A No.

Q And why is that?

A Yeah, so first of all, I don't see any real logical basis to connect an order in 1993, or whenever it was, with this case, with just all the contextual differences, ERCOT, Texas, the years, the technology, the composition of the generation mix, et cetera, et cetera. So just -- so I just don't see -- just take that one off the table.

So now we just go to the question of whether 4CP should be the method that they use. And TECO offered rationale that, you know, well, they had to do it because they agreed to do it in a settlement. I think they should honor their settlement, so I understand that.

They said that it has to do with the fact that they are adding a lot of generation that's solar. But a 4CP method compared to the 12CP, which I put up as an alternative, is a demand-based allocation method. It focuses on those -- well, in Texas, because it's driven by summer demand, it focuses on those four summer months, June, July, August and September. But TECO --

MR. MOYLE: Mr. Chair, I --

THE WITNESS: -- uses a different one, right?

MR. MOYLE: I let this go on. I didn't ask him the why on that. I was just trying to get the fact that it's what Texas has used. He has filed testimony on the approach he believes is appropriate. I don't think we need to, you know, have him go through what's in his testimony and --

MR. MARSHALL: Mr. Chairman, this is exactly

the purpose of redirect, is you --
CHAIRMAN LA ROSA: Yeah.
MR. MARSHALL: -- sometimes people have a cross-examination where they --
CHAIRMAN LA ROSA: Understood.
MR. MARSHALL: -- have a statement, and then the question is, well, why did you make that statement? How does that compare to what you believe now?
CHAIRMAN LA ROSA: Yeah. No -- understood. He is clarifying on his -- what he believes is what he needs to do.
BY MR. MARSHALL:
Q Did you complete your answer?
A Yeah. Just let me say -- I will be as brief as I possibly can.
So first of all, 4CP compared to 12CP, puts heavier weight on the demand of the classes. It raises issues like load factor, which is a bit of a red herring, because load factor just tells you -- I mean, 100 percent load factor customer is always on the peak, for example, right? And a 50-percent load factor customer may only be using their electricity off-peak. So load factor isn't, by itself, enough.
The company is adding a huge amount of solar

resources. I personally applaud that, but those are energy sources, not demand-related sources. So with cost causation, we should be looking to the energy requirements that the utility has, and apparently it doesn't have major capacity requirements.

So from -- whether you look at it from the generation that's being added or the planning and resource management that the utility is trying to do, we should be looking at the energy issues, not the demand-related issues, and using more peaks, even the token, sort of, January peak approach that the company uses recognizes something going on, which is that fewer peaks means greater volatility in the cost analysis, when we should be looking across the course of the year to capture those contributions of both high demand, high -- and high load factor customers, and then -- well, I will just leave it at that.

There is a number of reasons that says that this company is focused on energy. They should -- these customers are not increasing their demand that significantly. They are not adding plants like the old base load plants. They should be moving towards energy-based cost allocation to reflect what the company is doing to meet demand, and for energy and service.

Q Mr. Moyle also asked you about some of the

ERCOT rules, is that right?

A Yes.

Q When did you leave the Texas Commission?

A I left in 1995.

Q Do you believe that the Texas rules that you had to read today should apply to TECO?

A Yeah. No.

Q And why is that?

A It's just a completely different market structure company, completely different technology conditions, completely different demand patterns, completely different -- weather has changed. There is so many different reasons that it deserves its own look with Florida, Tampa, Hillsborough-based data, not what Texas is doing.

MR. MARSHALL: Great. Thank you, Mr. Chairman. That's all my questions.

CHAIRMAN LA ROSA: Thank you.

Is there exhibits you would like to enter into the record?

MR. MARSHALL: Yes. Mr. Chairman, we would like to enter Exhibits 72 through 76 into the record.

CHAIRMAN LA ROSA: Is there objections?

Seeing none, show them entered into the

record.

(Whereupon, Exhibit 72-76 were received into evidence.)

MR. MOYLE: FIPUG would like to move in FIPUG's cross-examination Exhibits F1 to F4.

CHAIRMAN LA ROSA: Okay. Do we have exhibit numbers for those?

MS. HELTON: Those are 784 to 787.

CHAIRMAN LA ROSA: Okay. Is there objections to those?

MR. MARSHALL: I am just checking my notes, Mr. Chairman. Were all those exhibits used? Yes. Okay. No objection.

CHAIRMAN LA ROSA: Okay. Seeing no objections, show them entered into the record.

(Whereupon, Exhibit Nos. 784-787 were received into evidence.)

CHAIRMAN LA ROSA: Are there further exhibits?

Seeing none, then Mr. Rabago, you are excused. Thank you, sir.

THE WITNESS: Thanks for the chance to visit Florida again. I appreciate it.

CHAIRMAN LA ROSA: Of course. No problem.

(Witness excused.)

CHAIRMAN LA ROSA: All right. So it is little bit -- almost 10:30. Let's take a 10-minute break till 10:35.

(Brief recess.)

CHAIRMAN LA ROSA: All right. Let's all grab our seats and -- let's all grab our seats and get rolling, see if we can make a nice stretch here between now and lunch.

We left off with Florida Rising/LULAC, you guys have, I believe, one more witness?

MR. MARSHALL: That's correct, Mr. Chairman. We would call MacKenzie Marcelin to the stand, and he has been previously sworn.

CHAIRMAN LA ROSA: That's right, he has, on day one. So welcome.

Whereupon,

MACKENZIE MARCELIN

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

EXAMINATION

BY MR. MARSHALL:

Q Could you please state your name and business address for the record?

A MacKenzie Marcelin, and the address is 10800 Biscayne Boulevard, Suite 1050, Miami, Florida, 33161.

Q And on whose behalf are you testifying today?
A Florida Rising and LULAC.
Q Mr. Marcelin, on June 6th, 2024, did you prepare and cause to be filed testimony and exhibits MM-1 through MM-5 in this docket?
A Yes, I did.
Q Do you have that testimony and those exhibits with you today?
A I sure do.
Q Do you have any changes to your prefiled testimony or exhibits?
A No.
Q So if I ask you the same questions today, would your answer be to the same?
A Yes.

MR. MARSHALL: Mr. Chairman, at this point I would like to have Mr. Marcelin's prefiled direct testimony entered into the record as though read.

CHAIRMAN LA ROSA: Okay.

(Whereupon, prefiled direct testimony of MacKenzie Marcelin was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Tampa Electric Company)))	DOCKET NO. 20240026-EI

TESTIMONY OF MACKENZIE D. MARCELIN

ON BEHALF OF

FLORIDA RISING AND LEAGUE OF UNITED LATIN AMERICAN CITIZENS

June 6, 2024

C26-2683

Q. Please state your name and business address.
A. My name is MacKenzie Marcelin. My business address is 10800 Biscayne Blvd Suite 1050, Miami, FL 33161.
Q. What is your current position?
A. I am the Climate Justice Director at Florida Rising.
Q. What are your duties as Climate Justice Director?
A. In my role I am responsible for developing campaign strategies that address the climate crisis from a racial justice lens at the local, state, and federal levels. I am also tasked with designing and implementing actions and events to mobilize base, allies, and partners toward key climate justice policy wins. Lastly, I develop and activate natural disaster response and manage disaster response initiative work.
Q. Please summarize your qualifications and work experience.
A. In 2019, I was hired as a climate justice organizer at Florida Rising where I began my organizing work in climate justice. My general qualifications include organizing for 6 years and organizing multiple energy justice campaigns. I have experienced electricity disconnections and know the hardships they can cause. I have personally experienced energy insecurity, and as a Floridian, have had to engage in preparation for multiple hurricanes. I have a Bachelor of Arts in History from the University of Florida, with a focus on the Black experience, race, and inequality. My litigation experience is limited, however, I have participated in a few dockets at the Florida Public Service Commission.
Q. Have you ever testified before the Florida Public Service Commission before?

A. Yes, I have participated in a few dockets at the Florida Public Service Commission advocating on behalf of Florida Rising's values of racial and economic justice and for Florida Rising's members, who are mostly black and brown, and are facing high energy burdens due to high electric bill costs. In Docket Nos. 20190015-EG, 20190016-EG, 20190018-EG, 20190020-EG, 20190021-EG, *In re: Commission review of numeric conservation goals*, I gave testimony to the importance of energy efficiency in helping customers lower energy bills, especially for low-income communities and communities of color. For more information, please see a transcript of my remarks here: http://www.psc.state.fl.us/library/filings/2019/08186-2019/08186-2019.pdf. In Docket No. 20200219-EI, *In re: Petition to initiate emergency rulemaking to prevent electric utility shutoffs, by League of United Latin American Citizens, Zoraida Santana, and Jesse Moody*, I gave testimony to the importance of halting electric power disconnections for the health of members of low-income communities. For more information, please see a transcript of my remarks here: http://www.psc.state.fl.us/library/filings/2020/11330-2020/11330-2020.pdf. In Docket No. 202000181-EU, *In re: Proposed amendment of Rule 25-17.0021, F.A.C., Goals for Electric Utilities*, I gave testimony to the importance of energy efficiency in helping customers lower energy bills, especially for low-income communities and communities of color. For more information, please see a video of my remarks here: http://psc-fl.granicus.com/MediaPlayer.php?view_id=2&clip_id=3368 and here: http://psc-fl.granicus.com/MediaPlayer.php?view_id=2&clip_id=3335.

C26-2685

Q. Have you ever testified as a formal witness before the Florida Public Service Commission?

A. Yes, in the FPL Rate Case I submitted formal testimony on behalf of Florida Rising (Docket 20210015-EI). That testimony can be found here: https://www.floridapsc.com/pscfiles/library/filings/2021/06451-2021/06451-2021.pdf. https://www.floridapsc.com/pscfiles/library/filings/2021/06451-2021/06451-2021.pdf. On June 5, 2024, I filed formal testimony in the energy-efficiency goal setting proceedings (Docket Nos. 20240012, 20240013, 20240014, 20240016, and 20240017). That testimony can be found here: https://www.floridapsc.com/pscfiles/library/filings/2024/04599-2024/04599-2024.pdf.

Q. On whose behalf are you testifying in this proceeding?

A. Florida Rising and LULAC.

Q. What is Florida Rising?

A. We are a people-powered organization made up of members advancing economic and racial justice across Florida. We build independent political power that centers historically marginalized communities so everyday Floridians can shape the future. As an organization, we engaged in the 2019 FEECA Hearings, intervened in the 2021 FPL Rate Case, commented on the energy-efficiency rulemaking proceeding (Docket No. 20200181), including in the Rule hearing, commented in some of the fuel dockets and storm recovery dockets, and, in addition to this proceeding, have intervened in the Duke Energy Florida Rate Case and energy-efficiency goal setting proceedings, happening at the same time as this case.

Q. Does Florida Rising have members in Tampa Electric Company's service

territory?

A. Yes, Florida Rising has a lot of members in the Tampa Bay area, with many members in Tampa Electric Company's ("TECO") service territory, with 105 active members in Hillsborough County. Also, Florida Rising as an organization pays electric bills to TECO for our office located in TECO's service territory.

Q. Why is Florida Rising in this proceeding?

A. As mentioned before, Florida Rising is an organization made up of members focused on empowering marginalized communities to advance racial and economic justice across Florida. In our climate justice work we want a future where the frontline and most impacted communities are at the center of energy policy, disaster response, and all climate change initiatives.

As I discuss below, TECO's residential customers, including Florida Rising's members, face some of the highest electricity bills in the nation. Our members face an affordability crisis between rising rents and rising electricity bills. While the Florida Public Service Commission does not regulate rental prices, they are supposed to regulate electricity prices.

Florida's dependency on fossil fuels has led to our current energy system polluting our communities, fueling our climate crisis, and leading many in dire economic straits. These issues in our energy system have an unequal and harmful impact on Black, Brown, and low-income communities. A 2020 report by ACEEE found that low-income, Black, Hispanic, and Native American households face higher energy burdens than the average household.[1] Rising housing costs, insurance costs, and stagnant wages have made Florida unaffordable, leaving families with high energy burdens. The

C26-2687

financial hardship is forcing people to make tough choices between keeping the lights on or paying for groceries or prescription medications or living in hot and unsafe housing conditions. All the while, major utility companies have been experiencing record profits over the last few years.

Florida has been experiencing an uptick in climate disasters like extreme heat, sea level rise, flooding, and severe storms, which are leaving our neighborhoods and infrastructure vulnerable. Record high heat days,[2] stronger and more frequent storms,[3] and other climate disasters are a direct result of our energy system's reliance on dirty fossil fuels. The increase in extreme heat days means that more energy and access to A/C are a requirement in Florida for keeping our homes healthy, habitable, and cool. Stronger and more frequent storms threaten the reliability of our electrical grid, causing loss of property to our state and an increase in illness and death. The increase in extreme disasters places an unfair burden on communities' colors and often leads them into a more vulnerable state than before.

Yet, Florida Rising believes that we must transition to a clean energy system with more community members included in the decision-making. If we do that, we can ensure that everyone has access to clean, affordable energy that creates jobs and is environmentally friendly and resilient against natural disasters.

Q. Have you looked at how TECO ranks nationally when it comes to residential electricity bills?

A. Yes, according to the most recent data from the Energy Information Administration ("EIA"), for 2023, TECO had the third highest electricity bills in the nation with an average monthly residential electricity bill of

$191.95 (of utilities with more than 100,000 residential customers).

Q. How did you determine this?

A. I simply calculated the average monthly revenue per residential customer for each utility and state and combined the data together. All of these calculations are included in my electric bill comparisons from the EIA 2023 data and are attached as Exhibit MM-1. TECO already admitted that the information it submits to the EIA is accurate and that its total billed revenue for the residential class divided for each month by the customer count for that month, averaged for all twelve months, results in $191.95. Although TECO denies the importance of this calculation, the calculation represents the average revenue per residential customer per month. In other words, it represents the average monthly residential electricity bill. TECO also admitted that, as presented by the EIA for 2023, of the 149 electric utilities with over 100,000 residential customers, TECO had the third highest average monthly residential electricity bills. These admissions are attached as Exhibit MM-2.

Q. Is this a standard-practice for comparing electric bills?

A. Yes, the Energy Information Administration calculates the average residential electric bills itself using this methodology and compares average monthly bills across utilities and states using this method every year.

Q. How do Florida-utilities frequently do "bill" comparisons?

A. They frequently do "bill" comparisons using a standardized 1,000 kWh assumption.

Q. What's your opinion regarding that kind of comparison?

A. It is an arbitrary and misleading comparison. Consumers do not pay bills based off of 1,000 kWh of usage; they pay bills off of actual usage. Florida utilities often have higher rates above 1,000 kWh of usage, and most average above 1,000 kWh of usage. Most utilities out of state have consumers that use less than 1,000 kWh of usage. Thus, 1,000 kWh of usage frequently understates the actual bills Florida consumers pay, while overstating the actual bills others pay.

Q. Have you looked at the impact of TECO's proposed rate increase in this case?

A. Yes. In 2023, TECO's residential customers averaged 1,157 kWh of usage. Assuming that usage stays roughly the same, under current rates, that same kWh of usage would cost $166.04 today (which is substantially less than in 2023 due to decreased fuel prices, although presumably lower fuel prices would apply to other utilities as well). Under their proposed rates, this usage would cost $184.25 in 2025. With the subsequent year adjustments, this rises to $196.96 by 2027, an over $30 increase in base rates per month from current bills.

Q. Isn't $166.04 less than $191.95?

A. Yes. Thankfully fuel prices have fallen and charges for storm recovery are falling off as well. However, fuel prices can be expected to rise again, and betting our residential electricity bills on the idea that no storms will hit TECO's service territory from now through the end of 2027 seems like a bad idea. So, if fuel prices rise or a storm hits (or both), residential electricity bills could be a lot, lot higher, and with the base rate increases TECO is proposing, could easily be the most expensive residential electricity bills in the nation.

Q. Why is that an issue?

A. Florida has increasingly become unaffordable. Housing and property insurance costs continue to rise with little to no increase in income. This dire situation is putting Floridians in an economic chokehold, especially for already marginalized communities. An increase in electricity bills lead to higher energy burden, which in turn can impact health and quality of life for many individuals. A higher energy burden can lead to individuals having to choose between paying for the bare necessities of survival, like keeping the power on or paying for rent, groceries, and/or medical supplies. Also, for TECO to have among the highest bills in the nation for such a small territory in comparison to FPL and Duke is ridiculous.

Q. Have you evaluated TECO's Energy Efficiency performance?

A. Yes. TECO has been meeting, and, in fact, greatly exceeding, all of their energy-efficiency goals as set by the Florida Public Service Commission. However, compared to national averages, their savings are still rather small. A common way of comparing actual performance on energy efficiency between utilities is to look at the total amount of energy each utility saved in a year as a percent of that utility's total retail sales for the same year. This gives a fair comparison of how each utility is doing, since in absolute numbers, a small utility with excellent energy efficiency achievements won't save as much total energy as a huge utility with abysmal performance.

In 2021, the latest year for which the analysis has been completed, the national average for energy savings as a percent of total retail sales was 0.68%. SACE Energy Efficiency in the Southeast Report (March 2023), attached as Exhibit MM-3, at 4. In that same year, TECO achieved 0.3%. *Id.*

at 20. TECO achieved roughly the same result in 2023. I have prepared a workpaper supporting these calculations and attached it as Exhibit MM-4.

Q. Do you have any recommendations in regards to TECO's Commercial and Industrial load control and load management programs?

A. Yes. As shown in Exhibit MM-5, TECO spent $22,761,449 on its Industrial Load Management program (almost entirely in the form of credits to participating customers), $3,849,871 on its Demand Response program, and $5,153,806 on its Standby Generator program, well over half of the total $47,132,152 it spent on demand-side management programs. Residential customers, of course, account for the majority of the funding for this program. I propose that these credits be cut by at least three-quarters, if not eliminated entirely, to bring them more in line with the value that they provide to customers.

Q. Please summarize your testimony.

A. TECO's residential customers, including Florida Rising members, already pay some of the highest residential electricity bills in the nation. The proposed massive base rate increases will leave TECO's residential customers vulnerable to the extraordinary energy burden TECO is proposing to place on them. If fuel prices increase, or a storm hits, or both, TECO's residential customers could very well end up paying the highest residential electricity bills in the nation. The affordability crisis is present now, and under TECO's proposal would only get much worse. The Florida Public Service Commission should be working towards lowering residential electric bills, and working to drop TECO down in the national rankings. If the goal isn't to have the highest residential electric bills in the nation, the proposed rate increase should be rejected and TECO should be instructed to shift some of the cost-burden onto its large commercial and industrial customers. Increasing rates as TECO has proposed would increase unaffordability and limit access to our energy systems. For many, limiting access to the energy we all need to survive in this modern day would perpetuate and exacerbate inequality, particularly for low-income and communities of color already facing systemic burdens. A fair and just energy system should ensure that all Floridians, especially the most vulnerable of us, have access to the affordable energy we need to live a quality life.

Q. Does this conclude your testimony?

A. Yes, it does.

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[1] Ariel Drehobl, Lauren Ross, & Roxana Ayala, American Council for an Energy-Efficient Economy, How High Are Household Energy Burdens? at 9-13 (2020), https://www.aceee.org/research-report/u2006.

[2] Ian Livingston, *Florida is roasting in extreme heat and on pace for a record-warm year*, Washington Post (Aug. 11, 2023), https://www.washingtonpost.com/weather/2023/08/11/florida-record-heat-climate-summer/.

[3] Nat'l Oceanic & Atmospheric Admin., *NOAA predicts above-normal 2024 Atlantic hurricane season* (May 23, 2024), https://www.noaa.gov/news-release/noaa-predicts-above-normal-2024-atlantic-hurricane-season.

C26-2693

BY MR. MARSHALL:
Q Mr. Marcelin, did you prepare a summary of your testimony?
A Yes.
Q Would you please go ahead and give us your summary?
A Will do.

My name is MacKenzie Marcelin. I serve as the Climate Justice Director for Florida Rising. Florida Rising is a people-powered organization made up of members advancing economic and racial justice across Florida. We build independent and political -- independent political power that centers historically marginalized communities so everyday Floridians can shape the future.

As the Climate Justice Director, I am responsible for developing campaign strategies that address the climate crisis from a racial and economic justice lens at the local, state and federal levels.

I am also tasked with designing and implementing programs and events to mobilize our base of members, allies and partners to achieve key climate justice policy wins.

Lastly, I develop and activate natural disaster response, and manage disaster response initiative work.

In our climate justice work, we want a future where the frontline and most impacted communities are at the center of energy policy, disaster response and all climate change initiatives.

We seek to have historically marginalized communities at the forefront, because too often, much of the burden of climate crisis falls on communities. Despite being the most vulnerable, we are usually excluded when government experts and corporations are where the solutions are made. Thus, we are not accounted for, and unable to reap the rewards of said solutions.

For too long, we have been -- we have seen residential customers and marginalized communities' voices not adequately accounted for regarding energy policies and decisions in Florida. Due to that fact, the burden of our energy systems, and the burden of energy costs falls on residential clusters, particularly black, brown and low-income communities in Florida.

A 2020 ACEEE report found that Black, Hispanic and Native American households face high energy burdens than the average household. Our goal as Florida Rising, as an intervening party, and as a witness, is to ensure that communities that we represent are not left out of these proceedings, and that our voices are heard, so that we no longer have to deal with the burden of our energy system that is adding to the unaffordability crisis we are experiencing in Florida.

We want residential customers in our most vulnerable communities at the forefront of the solutions and decision-making, because there is no solution if a solution does not address the most vulnerable.

For that reason, as an organization, we engage in various proceedings in relations to energy in Florida, such as the 2019 FEECA hearings; we have intervened in the 2021 FPL rate case; commented on the energy efficiency ruling proceedings, including the real hearing; commented on some of the fuel docs and storm recovery dockets. And in addition to these, proceedings have intervened in the Duke Energy rate -- Florida rate case, and energy efficiency goal setting proceedings.

Regarding this -- these proceedings TECO residential customers and Florida Rising members living in TECO territories face some of the highest electricity bills in the nation. Increasing energy costs, compounded with rising rent, insurance and stagnant wages have led to a real unaffordability crisis. This financial hardship is causing families to make tough decisions between keeping the lights on, paying for necessities like groceries, prescription medication and/or living in a hot and unsafe housing conditions.

We have seen how Florida has been experiencing uptick in climate disasters like extreme heat, sea level rise, flooding and severe storms, which are leaving our neighborhoods vulnerable. Record high heat days, stronger and more frequent storms and other climate disasters are often, unfortunately, a direct result of our energy system's reliance on fossil fuels.

It is unfair that residential customers must deal with the unequal economic burden and the health impacts of our energy system. These are real-life experiences that many of our members are actively dealing with, because TECO has the third highest electricity bills in the nation of majority utilities with more than 100,000 residential customers. Increasing rates and bills even more will only exasperate the many problems that we already face.

To summarize, high costs are leaving our communities suffering on multiple levels. We must contend with the unfair and unequal burden of paying for the energy system and making concessions that impact our finances. Moreover, because dirty, volatile fossil fuels drive this energy system, residential customers must contend with the climate crisis resulting from

TECO's reliance on fossil fuels which impacts their health and safety.

While residential customers must deal with the ramifications of this system, large commercial and industrial customers are actively receiving excessively high credits of tens of millions of dollars per year for little in return. The very same credits are contributing to higher costs. Those credits should be drastically reduced, if not eliminated.

To conclude my summary, I urge TECO, the Commission, and everyone in this room to heed the words of residents who have unequivocally asked not to increase rates.

That concludes my summary.

Q Thank you.

MR. MARSHALL: Mr. Chairman, we tender the witness for cross-examination.

CHAIRMAN LA ROSA: Great. Thank you.

OPC.

MR. REHWINKEL: No questions.

CHAIRMAN LA ROSA: FIPUG.

MR. MOYLE: No questions.

CHAIRMAN LA ROSA: FEA.

CAPTAIN GEORGE: No questions.

CHAIRMAN LA ROSA: FRF.

MR. LAVIA: No questions.
CHAIRMAN LA ROSA: Walmart.
MS. EATON: No questions.
CHAIRMAN LA ROSA: TECO.
MR. WAHLEN: No questions.
CHAIRMAN LA ROSA: Staff.
MR. SPARKS: No questions.
CHAIRMAN LA ROSA: Commissioners, any questions?
Seeing none, send it -- I am sorry. Sorry. Seeing none, I send back to Florida Rising for redirect.
MR. MARSHALL: No redirect, Mr. Chairman.
CHAIRMAN LA ROSA: So let's move to exhibits.
MR. MARSHALL: Mr. Chairman, we move in Exhibits 77 through 81.
CHAIRMAN LA ROSA: Okay. Is there objection?
Seeing none, show those exhibits entered into the record.
(Whereupon, Exhibit Nos. 77-81 were received into evidence.)
MR. MARSHALL: We would ask that the witness be excused at this point.
CHAIRMAN LA ROSA: Are there any other exhibits? I don't believe there are any. Yes,

witness may be excused. Thank you.

MR. MARCELIN: Thank you.

(Witness excused.)

(Transcript continues in sequence in Volume 12.)

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 videotaped 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 4th day of October, 2024.

DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #HH575054
EXPIRES AUGUST 13, 2028