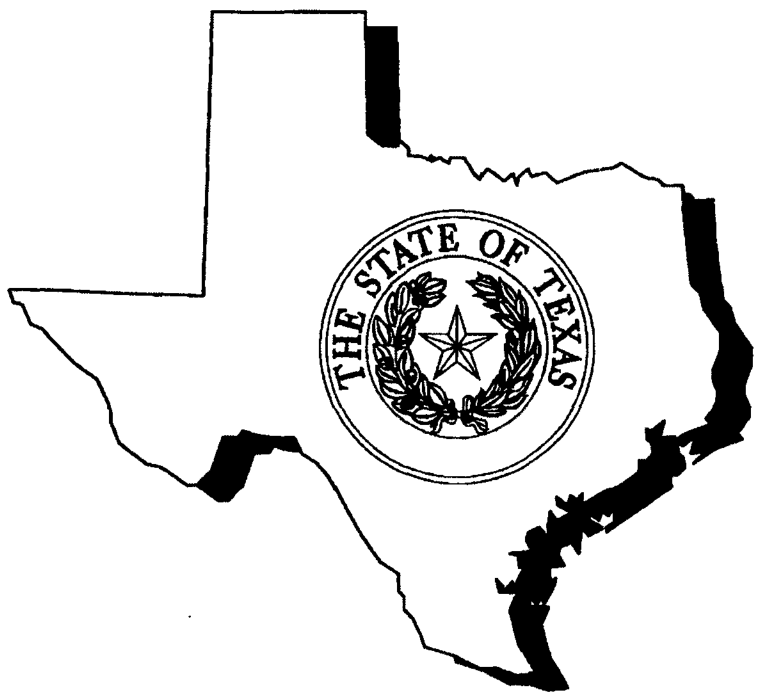
Control Number: 49421

Item Number: 525

Addendum StartPage: 0

SOAH DOCKET NO. 473-19-3864
PUC DOCKET NO. 49421

APPLICATION OF CENTERPOINT ENERGY HOUSTON ELECTRIC LLC FOR AUTHORITY TO CHANGE RATES	§ § § § § §	**BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS**



REDACTED DIRECT TESTIMONY OF

BRIAN T. MURPHY

RATE REGULATION DIVISION

PUBLIC UTILITY COMMISSION OF TEXAS

JUNE 12, 2019

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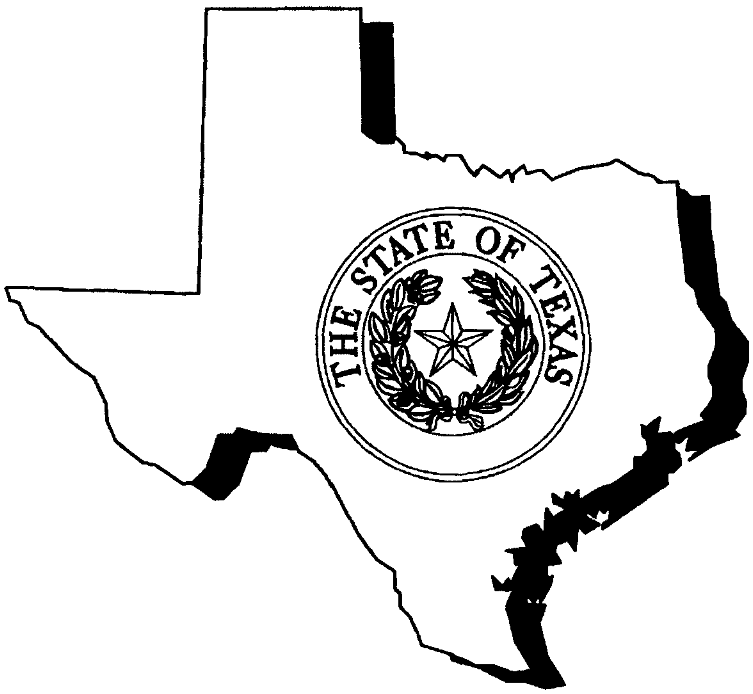

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TABLE OF CONTENTS

ATTACHMENTS:

I. PROFESSIONAL QUALIFICATIONS

Q. Please state your name and business address.

A. Brian T. Murphy, 1701 N. Congress Avenue, Austin, TX 78711-3326.

Q. By whom are you employed and in what capacity?

A. I am employed by the Public Utility Commission of Texas ("PUC" or "the Commission") as a Senior Rate Analyst in the Tariff and Rate Analysis Section of the Rate Regulation Division.

Q. What are your principal responsibilities as a Senior Rate Analyst for the Public Utility Commission of Texas?

A. My principal responsibility is to analyze utility tariff filings, cost allocation, and rate design. My responsibilities include preparing and presenting testimony as an expert witness on cost allocation, rate design, and tariff administration issues in docketed proceedings before the Commission and the State Office of Administrative Hearings ("SOAH").

Q. Please state your educational background and regulatory experience.

A. I have provided a summary of my educational background and regulatory experience, including a listing of my previously filed written testimony in Commission proceedings, in Attachment BTM-1.

II. SCOPE OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding, Docket No. 49421, *Application of CenterPoint Energy Houston Electric LLC for Authority to Change Rates*?

A. My testimony regarding CenterPoint Energy Houston Electric's (CEHE's) application will address cost allocation, revenue distribution, rate design, and tariff issues. I will address part or all of the following issues from the Preliminary Order (as numbered therein):

6. What is CenterPoint's transmission cost of service determined in accordance with PURA and Commission rules?

   Response: *See* Section VI of my testimony.

37. Have any revenues received for expenses attributable to transmission service to export power from or import power to ERCOT been properly reflected in CenterPoint's requested rates?

   Response: Yes.

40. What are the appropriate amounts, if any, for transmission expenses and revenues under Federal Energy Regulatory Commission (FERC)-approved tariffs to be recovered?

   Response: The appropriate amounts are reflected in Staff's cost study.

43. What are CenterPoint's just and reasonable rates, calculated in accordance with PURA and Commission rules? Do the rates comply with the requirements of PURA § 36.003?

   Response: *See* Section XII of my testimony.

44. What are the appropriate rate classes for which rates should be determined? Is CenterPoint proposing any new rate classes? If so, why are these new rate classes needed?

Response: *See* Section VIII of my testimony.

45. What are the appropriate billing and usage data for CenterPoint's test year? What known and measurable changes, if any, should be used to adjust the test-year data? What changes, if any, are necessary to reflect abnormal weather conditions or other aberrant conditions?

Response: *See* Section IX of my testimony.

46. What are the appropriate allocations of CenterPoint's revenue requirement to functions and rate classes?

a. Does CenterPoint have any customer-specific contracts for the provision of transmission or distribution service? If so, identify each customer and state whether the contract has been presented to the Commission for approval, and if so, in what docket. In addition, has CenterPoint appropriately allocated revenues and related costs associated with such contracts? Do all allocation factors properly reflect the types of costs allocated?

b. What are the appropriate allocations of CenterPoint's transmission investments, expenses, and revenues, including transmission expenses and revenues under FERC-approved tariffs, among jurisdictions?

Response: *See* Sections V (function) and VIII (class) of my testimony.

47. What are the appropriate rates for exports of power from ERCOT, calculated in accordance with 16 TAC 25.192(e) and ERCOT protocols?

Response: *See* Section VII of my testimony.

48. Does CenterPoint provide wholesale transmission service at distribution voltage to any customers? If so, has CenterPoint properly allocated costs to, and designed rates for, those customers as required under PURA § 35.004(c)?

Response: No.

49. Are all rate classes at unity? If not, what is the magnitude of the deviations, and what, if anything, should be done to address the lack of unity?

Response: *See* Section XI of my testimony.

50. What tariff revisions, if any, are appropriate as a result of this proceeding?

Response: *See* Sections XIII of my testimony.

51. Has CenterPoint proposed any rate riders? If so, should any of the proposed riders be adopted? If so, what are the appropriate costs to be recovered through the riders, and what are the appropriate terms and conditions of the riders?

a. Should the Commission approve CenterPoint's proposed rider to refund certain unprotected excess-deferred income tax (UEDIT) amounts, Rider UEDIT?

Response: *See* Section XIV of my testimony.

52. Does CenterPoint have any existing rate riders that should be modified or terminated? What regulatory assets or other items are currently being recovered through rate riders?

Response: The Company's riders CTC and SBF are obsolete and will be removed from the Tariff.[1] Staff witness Filarowicz addresses the second question.

III. SUMMARY OF RECOMMENDATIONS

Q. Please summarize your recommendations.

A. With respect to the *functionalization* of costs, I recommend that

- Texas Gross Margins Tax expenses included in Account 408.1 be functionalized in proportion to base revenues; and,
- Miscellaneous general expenses included in Account 930.2 be functionalized following the methodology presented in my testimony, which is more granular as compared with the Company's proposed approach.

With respect to *wholesale transmission service*, I recommend that

- The Company's wholesale TCOS be set to $336,923,105; and,
- The Company's annual access fee be set to $4.8569719 per kilowatt of ERCOT 4-CP demand.

With respect to *retail delivery service*, I recommend that

- The Company's ERCOT transmission payments be set at $927,700,584 reflecting Staff's downward adjustments to CEHE's requested wholesale TCOS;
- ERCOT transmission payments be allocated among classes in proportion to demand at source coincident with ERCOT 4CP demand;
- Class revenue requirements be set directly to class cost of service as determined by Staff;
- For each class, rates be set to the levels shown in Attachment BTM-7; and,
- The Company's proposal to amend its lighting tariff to mandate LED lighting be rejected.

[1] Direct Testimony of Matthew A. Troxle at 39.

With respect to *rate riders*, I recommend that

- UEDIT be functionalized among wholesale transmission and retail delivery service in proportion to the UEDIT amounts included in the Company's rates in Docket Nos. 48065 and 48226;
- CEHE be ordered to present in its compliance tariff a wholesale rate rider designed to return wholesale's assigned share of UEDIT to the Company's wholesale customers during a one-year period, consistent with Staff's recommended functionalization of UEDIT; and,
- In the event plant disallowances are adopted by the Commission in this proceeding; and, in the event the disallowed plant was included in an interim TCOS or DCRF, the quantification of the over-recovered amounts associated with that plant to be refunded to ratepayers be severed into a separate proceeding.

IV. OVERVIEW OF RATEMAKING FOR T&D UTILITY

Q. Please provide a general description of a transmission and distribution utility's (TDU's) filing for authority to change base rates.

A. In a filing for authority to change base rates, a utility (CEHE in this proceeding) places its accounting and load information during a chosen test year from its books and records into the rate filing schedules contained in the Commission's Transmission & Distribution Investor-Owned Utilities Rate Filing Package for Cost of Service Determination ("Filing Package" or "RFP"). Collectively, these schedules comprise the cost of service study.

The two basic components of cost of service are allowable expenses and return on rate base. Allowable expenses include the operating and maintenance expenses, depreciation and amortization expenses, federal income taxes, and other taxes net of other revenues. Rate base includes invested capital used and useful in the provision of transmission and distribution services, including but not limited to transmission lines, switching stations, substations, feeder lines, poles, line transformers, service drops, and meters. Return on rate base is calculated as a function of return on equity, cost of debt, and capital structure.

The Filing Package requires that expenses and rate base be broken out and stated as individual line items in accordance with the Federal Energy Regulatory Commission's (FERC's) Uniform System of Accounts. The cost of service is initially stated on a total company basis,[2] then disaggregated in later steps of the ratemaking process, as discussed below. Witness Mark Filarowicz presents Staff's calculation of CEHE's company total requested revenue requirement,[3] reflecting his adjustments and the adjustments of other Staff witnesses who address cost-of-service issues.

Q. What is the next step in the ratemaking process for a T&D utility?

A. The Filing Package requires that costs be separated into the following business functions:

- Transmission,
- Distribution,
- Metering, and
- Customer Service.[4]

[2] Net of wholesale revenues as presented by CEHE.

[3] This is the term CEHE uses for its retail delivery revenue requirement. The wholesale revenue requirement is overlaid within the retail cost of service's transmission function, and Account 565 is used in that function as a plug to ensure that the transmission functional "revenue requirement" ties to the Company's total wholesale transmission expenses, which are costs associated with serving CEHE's retail customers that the Company incurs in its role as a DSP.

[4] Please note that CenterPoint has consolidated the Billing function specified in the Filing Package with the TDCS function, which is reasonable.

Q. Why is it necessary to separate CEHE's costs into business functions?

A. The Company provides two basic types of service: wholesale transmission service (to other utilities); and, retail delivery service (to end-use retail customers).[5]

The separation of costs into business functions, called "functionalization," is critical to the identification of the costs to be assigned to each basic type of service. Costs incurred to provide wholesale transmission service will be included in wholesale transmission cost of service (TCOS).[6] Costs to provide retail service will be included in the retail delivery cost of service.

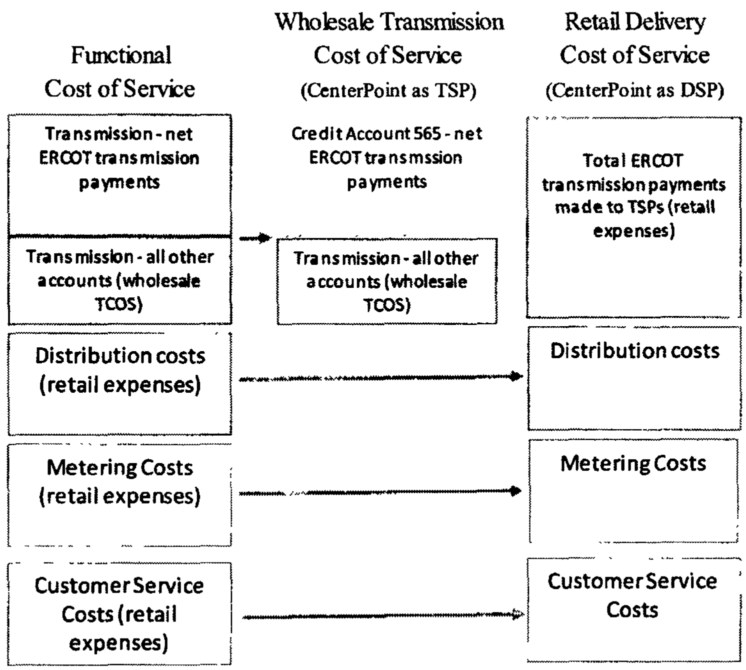
Q. Please provide a visual depiction of the costs included in wholesale TCOS versus retail cost of service.

A. As follows:

Figure BTM-1

[5] 16 TAC § 25.5(13): **Retail customer** -- The separately metered end-use customer who purchases and ultimately consumes electricity.

[6] 16 TAC § 25.192(e): **Transmission cost of service**. The transmission cost of service for each TSP shall be based on the expenses in Federal Energy Regulatory Commission (FERC) expense accounts 560-573 (or accounts with similar contents or amounts functionalized to the transmission function) plus the depreciation, federal income tax, and other associated taxes, and the commission-allowed rate of return based on FERC plant accounts 350-359 (or accounts with similar contents or amounts functionalized to the transmission function), less accumulated depreciation and accumulated deferred federal income taxes, as applicable.



Q. Which business functions are included in the wholesale TCOS?

A. As seen above, all costs assigned to the transmission function with the exception of expenses in Account 565 (net ERCOT transmission payments) are included in the wholesale TCOS.

Q. What is wholesale transmission service?

A. Texas operates its own transmission grid, which is contained within the State. Power is transmitted throughout the grid from the source (a market generator) to points of interconnection with the grid's wholesale customers (distribution utilities throughout the grid).[7] The grid is operated and administered by the Electric

[7] The Commission's full definition of wholesale transmission service can be found at 16 TAC § 25.5(138): **Transmission service** -- Service that allows a transmission service customer to use the transmission and distribution facilities of electric utilities, electric cooperatives and municipally owned utilities to efficiently and economically utilize generation resources to reliably serve its loads and to deliver power to another transmission service customer. Includes construction or enlargement of facilities, transmission over distribution facilities, control area services, scheduling resources, regulation services, reactive power support, voltage control, provision of operating reserves, and any other associated electrical

Reliability Council of Texas (ERCOT), and is referred to as the "ERCOT transmission grid" or simply "ERCOT."[8] Wholesale customers pay for access to the ERCOT transmission grid.

Although the ERCOT transmission grid is operated as a single integrated system, a multitude of individual utilities own portions of the grid.

Q. Which utilities own a portion of the grid?

A. There are 49 utilities that own a portion of the grid, including investor-owned transmission & distribution utilities,[9] investor-owned transmission-only utilities,[10] municipalities,[11] electric cooperatives,[12] and a river authority.[13]

A utility that owns a portion of the grid is referred to as a "transmission service provider" (TSP).[14]

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service the commission determines appropriate, except that, on and after the implementation of customer choice in any portion of the Electric Reliability Council of Texas (ERCOT) region, control area services, scheduling resources, regulation services, provision of operating reserves, and reactive power support, voltage control and other services provided by generation resources are not "transmission service."

[8] 16 TAC § 25.5(39) (relating to definitions): **Electric Reliability Council of Texas (ERCOT)** -- Refers to the independent organization and, in a geographic sense, refers to the area served by electric utilities, municipally owned utilities, and electric cooperatives that are not synchronously interconnected with electric utilities outside of the State of Texas. 16 TAC § 25.5(39): **ERCOT region** -- The geographic area under the jurisdiction of the commission that is served by transmission service providers that are not synchronously interconnected with transmission service providers outside of the state of Texas.

[9] CenterPoint, Oncor, Texas-New Mexico Power, AEP Texas Central Division, AEP Texas North Division, and Sharyland.

[10] Electric Transmission Texas, Wind Energy Transmission of Texas, Cross Texas Transmission, and Lone Star Transmission.

[11] Austin Energy, Brownsville Public Utilities Board, Bryan Texas Utilities, College Station, City of Denton Municipal Electric, Floresville Electric Power System, Garland Power and Light, GEUS (Formerly Greenville), Kerrville Public Utility Board, New Braunfels Utilities, San Antonio City Public Service, and Texas Municipal Power Agency.

[12] Bandera, Bluebonnet, Brazos, Central Texas, Cherokee County, Deep East Texas, East Texas, Fannin, Farmers, Fayette, Golden Spread, Grayson-Collin, Guadalupe Valley, Houston County, Lamar County, Lyntegar, Pedernales, Rayburn Country, Rio Grande, San Bernard, San Miguel, South Texas, Southwest Texas, Taylor, Trinity Valley, and Wood County Electric Cooperative.

[13] Lower Colorado River Authority.

[14] 16 TAC § 25.5(140): **Transmission Service Provider**—an electric utility, municipally-owned utility, or electric cooperative that owns or operates facilities used for the transmission of electricity.

Q. What portion of the grid is owned by each TSP?

A. A TSP's portion of total wholesale transmission revenues from the grid is equal to that TSP's wholesale transmission rate divided by the sum of all TSPs' wholesale transmission rates. For example, at the time of the Commission's last docket to establish ERCOT transmission payments,[15] CEHE's wholesale transmission rate was $5.781925 per kilowatt; the sum of all wholesale transmission rates was $54.567752 per kilowatt; and, CEHE's share of wholesale transmission revenues was 10.59%.

The Company's TCOS and wholesale transmission rate will be updated in this proceeding, and its revenue share will change. Staff's recommended TCOS for CEHE is $336,923,105.28 and wholesale transmission access rate is $4.8569719 per kilowatt,[16] as further discussed later in my testimony.

Ownership of a portion of the grid is the basis for a TSP's claim to a share of the transmission payments made by the grid's customers. At the time of Docket No. 48928, CEHE (acting in its role as a TSP) was receiving approximately 10.59% of all ERCOT transmission payments because it owned that percentage of the grid.

Q. Who are the grid's customers?

A. Other utilities. The grid's wholesale customers are load serving entities that provide distribution services to retail customers.[17] At the time of Docket No.

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[15] *Commission Staff's Petition to Set 2019 Wholesale Transmission Service Charges for the Electric Reliability Council of Texas*, Docket No. 48928.

[16] Per kilowatt of ERCOT Average 4CP demand.

[17] The Commission's full definition of a transmission service customer can be found at 16 TAC § 25.5(139): **Transmission service customer** -- A transmission service provider, distribution service provider, river authority, municipally-owned utility, electric cooperative, power generation company, retail electric provider, federal power marketing agency, exempt wholesale generator, qualifying facility, power marketer,

48928, there were 123 load serving entities that established load for the purpose of the assessment of wholesale transmission service charges in ERCOT (as listed below, in some instances a single distribution utility is shown with multiple load entries).[18]

The grid's wholesale customers are mostly municipalities and electric cooperatives, but also include investor-owned distribution utilities like Oncor Electric Delivery Company LLC.

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or other person whom the commission has determined to be eligible to be a transmission service customer. A retail customer, as defined in this section, may not be a transmission service customer.

[18] AEP Texas Central Company, AEP Texas North Company, Bandera Electric Co-op Inc, Bartlett Electric Co-op Inc, Big Country Electric Co-op Inc, Bluebonnet Electric Co-op Inc, Brazos Electric Power Co-op Inc, Brownsville Public Utilities Board, Bryan Texas Utilities, CenterPoint Energy Houston Electric LLC, Central Texas Electric Co-op Inc, Cherokee County Electric Co-op Assoc, City of Austin dba Austin Energy, City of Bartlett, City of Bastrop, City of Bellville, City of Boerne, City of Bowie, City of Brady, City of Brenham, City of Bridgeport Mun Elec Sys, City of Burnet, City Coleman, City of College Station, City of Cuero, City of Farmersville, City of Flatonia, City of Floresville dba Floresville Elec Light and Power, City of Fredericksburg, City of Garland, City of Georgetown, City of Giddings, City of Goldsmith, City of Goldthwaite, City of Gonzales, City of Hallettsville, City of Hearne Municipal Electric System, City of Hempstead, City of La Grange, City of Lampasas, City of Lexington, City of Llano, City of Lockhart, City of Luling, City of Mason, City of Moulton, City of Robstown Utility System, City of San Marcos, Ciy of San Saba, City of Sanger, City of Schulenburg, City of Seguin, City of Seymour, City of Shiner, City of Smithville, City of Waelder, City of Weimar, City of Whitesboro, City of Yoakum, Colemand County Electric Co-op Inc, Comanche Electric Co-op Assoc, Concho Valley Electric Co-op Inc, Cooke County Electric Co-op Assoc Inc, CPS Energy, Deep East Texas Electric Co-op Inc, Denton Country Elec Co dba CoServe Electric, Denton Municipal Electric, Fannin County Electric Co-op Inc, Farmers Electric Co-op Inc, Electric Co-op Inc dba FEC Electric, Farmers Electric Co-op Inc NPL, Farmers Electric Co-op Inc PRTN RC, Fayette Electric Co-op Inc, Fort Belknap Electric Co-op Inc, GEUS, Granbury Municipal Utilities, Grayson Collin Electric Co-op Inc, Guadalupe Valley Electric Co-op Inc, Hamilton County Electric Co-op, Heart of Texas Electric Co-op Inc, Hilco Electric Co-op Inc, Houston County Electric Co-op Inc, J A C Electric Co-op Inc, Jackson Electric Co-op Inc, Jasper Newton Electric Co-op Inc, Karnes Electric Co-op Inc, Kerrville Public Utility Board, Lamar County Electric Co-op dba LEC, Lamar County Electric Co-op dba LEC RC HOUPL, Lighthouse Electric Co-op, Lyntegar Electric Co-op Inc, Magic Valley Electric Co-op Inc, Medina Electric Co-op Inc, Mid South Electric Co-op Assoc, Navarro County Electric Co-op Inc, Navasota Valley Electric Co-op Inc, New Braunfels Utilities, Nueces Electric Co-op Inc, Oncor Electric Delivery Company LLC, Pedeernales Electric Co-op Inc, Rio Grande Electric Co-op Inc, Rusk County Electric Co-op Inc, Sam Houston Electric Co-op Inc, San Bernard Electric Co-op, San Patricio Electric Co-op, South Plains Electric Co-op Inc, South Texas Electric Co-op Inc, Southwest Texas Electric Co-op Inc, Taylor Electric Co-op Inc Abilene, Texas-New Mexico Power Company, Tri-County Electric Co-op Inc, Trinity Valley Electric Co-op, Trinity Valley Electric Co-op Incl LPL, United Electric Coop Services Inc, Victoria Electric Co-op Inc, Weatherford Municipal Utility System, Western Farmers Electric Co-op, Wharton County Electric Co-op Inc, Wise Electric Co-op, Wood County Electric Co-op Inc.

Q. How are the costs of the ERCOT transmission grid assessed to the grid's wholesale customers?

A. Wholesale customers pay for access to the integrated grid. For each customer, the access fees are based on that customer's load on the grid at the time of the grid's monthly peak loads in June, July, August and September of the prior year's summer.[19] The ERCOT grid's average load at these times is referred to as the "ERCOT Average 4-CP" load.[20] A wholesale customer's load coincident with the ERCOT Average 4-CP load is referred to as its "DSP Average 4-CP" load.

Summer peak loads are used to assess transmission charges because the ERCOT grid is summer-peaking. Summer peak loads drive the need for transmission capacity on the grid. The use of summer peak loads to assess charges is therefore a rate design that is consistent with cost causation, a ratemaking principle discussed further below.

Q. Above, you mentioned that Oncor is a wholesale customer of the grid. What about CEHE?

A. Yes. CEHE is also a load serving entity while acting in its role as a distribution service provider ("DSP").[21] The Company receives power from the ERCOT transmission grid, distributes the power through its distribution system, and delivers

[19] 16 TAC § 25.192(b)(1): ... The monthly transmission service charge to be paid by each DSP is the product of each TSP's monthly rate as specified in its tariff and the DSP's previous year's average of the 4CP demand that is coincident with the ERCOT 4CP.

[20] The "C" in "CP" refers to coincidence, but ERCOT's peak demands are not measured as coincident with any other system.

[21] 16 TAC § 25.5(33): **Distribution service provider (DSP)** -- An electric utility, municipally-owned utility, or electric cooperative that owns or operates for compensation in this state equipment or facilities that are used for the distribution of electricity to retail customers, as defined in this section, including retail customers served at transmission voltage levels.

the power to its end-use retail delivery customers. The wholesale transmission charges the Company incurs as a DSP must be assessed to and collected from its retail customers.

Q. What share of total payments for wholesale transmission service in ERCOT were assigned to CEHE (acting in its role as a DSP) in Docket No. 48928, to be paid by the Company's retail customers?

A. The share assigned to CEHE was 24.97%, calculated as the Company's DSP Average 4-CP load of 17,323.4 MW divided by ERCOT Average 4-CP load of 69,369.0 MW.[22]

Q. Where do the wholesale transmission charges incurred by CEHE as a DSP appear in the cost study in this proceeding?

A. The Company's requested ERCOT transmission payments in the amount of $942,402,945 can be found in Schedule III-A TCOS Calculation.[23] As presented by CEHE, the ERCOT transmission payments shown in the functional separation of costs are stated net of wholesale revenues the Company receives as a TSP; and, is included in FERC Account 565, the generic description of which is "transmission of electricity by others."[24] In the functionalization of costs as presented by CEHE, net ERCOT transmission payments are assigned to the transmission function.

[22] *Commission Staff's Petition to Set 2019 Wholesale Transmission Service Charges for the Electric Reliability Council of Texas*, Docket No. 48928, Commission Staff's Final Transmission Charge Matrix at worksheet 2018 4CP calculation (Feb 14, 2019).

[23] *See* electronic copy of the RFP, workpaper "Schedule H-I-J and CA.XLS," worksheet "II-A TCOS Calculation," at Microsoft Excel row 25. This amount includes recovery of a share of CEHE's requested TCOS, not the Company's TCOS reflecting Staff's adjustments.

[24] Net of wholesale transmission revenues credited to transmission expenses. Total ERCOT transmission payments ($942.4 million) minus requested wholesale revenues ($395.8 million) = net ERCOT transmission payments included in functional separation of costs ($546.6 million).

However, the Company's total wholesale transmission charges are the responsibility of CEHE acting in its role as DSP; are included in the cost of service for each retail class; and, are shown under each retail class's rate schedule as "transmission system charges."[25]

Q. Returning to the functional separation of costs in the cost study, which business functions' costs are included in the retail cost of service?

A. Costs assigned to the transmission, distribution,[26] metering,[27] and customer service[28] functions. As shown above in Figure BTM-1, the transmission function includes wholesale transmission charges to CEHE as a DSP.

V. FUNCTIONALIZATION OF COSTS

Q. Does the Filing Package provide a process for the functionalization of costs?

A. Yes. The Filing Package provides:

> Costs … shall be assigned to the functions using the following three-tier process.
>
> a. [Direct Assignment] For each FERC account, costs shall be directly assigned to functions to the extent possible, and all relevant workpapers provided …
>
> b. [Account-Specific] The utility shall provide detailed workpapers documenting the nature of any costs that cannot be directly assigned. For adequately documented costs, the utility may derive an account-specific functionalization factor based on the directly assigned costs or appropriate cost-causation principles…

[25] *See*, e.g., Direct Testimony of Matthew Troxle, Exhibit MAT-9 at 83. CenterPoint's requested transmission system charge under the proposed residential rate schedule is $.015080 per kWh.

[26] The distribution function includes the costs of distribution substations, poles towers and fixtures, overhead and underground feeder lines at primary and secondary voltage levels, conduit, line transformers, and service drops; and, it also includes the expenses incurred to operate and maintain distribution plant.

[27] The metering function includes the costs of meters, meter reading, and associated operations and maintenance expenses.

[28] The customer service function includes intangible plant costs (e.g., software systems), and customer-related expenses such as billing, record-keeping, and customer assistance.

> c. [Last Resort] If adequately documented costs remain for which direct assignment or account specific functionalization cannot be identified, the appropriate functionalization factor prescribed in Schedule F may be used. These functionalization factors shall only be used as a last resort...[29]

During the initial unbundling of costs in 2000, the Commission found that amounts should be directly assigned to the functions to the maximum extent reasonably possible, consistent with cost causation, even for amounts that are difficult to assign directly.[30]

Q. The Filing Package references cost-causation. What is cost causation and how does it relate to cost allocation?

A. Cost causation is the ratemaking principle that costs are to be assigned to those customers who cause the costs to be incurred by the utility. Section 25.234 of the Commission's Substantive Rules requires that rates be based on cost;[31] therefore, cost causation is the most important principle in cost allocation. In this proceeding, cost causation is equally important in the functional and class cost allocation steps in ratemaking.

To perform an allocation of costs consistent with cost causation, the analyst performs an inquiry into the nature of the costs, then identifies the usage

[29] Filing Package, Project No. 39548, at 9 (Nov 19, 2015).

[30] *Texas Utilities Electric Company Filing in Compliance with Subst. R. 23.67*, Docket No. 15638, Order at 2 (Oct 20, 1997): "**Functionalization of general and administrative expenses.** ... The Commission prefers that costs be directly assigned, even for expenses that are difficult to assign directly but concludes that TU Electric has not met its burden of establishing that the general and administrative expenses it proposed in this case are reasonable. **Functionalization of general plant.** .... The Commission prefers that costs be directly assigned, even for plant costs that are difficult to assign directly but concludes that TU Electric has not met its burden of establishing that the general plant costs it proposed in this case are reasonable."

[31] 16 TAC § 25.234(a): "**Rates** shall not be unreasonably preferential, prejudicial, or discriminatory, but shall be sufficient, equitable, and consistent in application to each class of customers, and **shall be based on cost.**" (emphasis added)

characteristics or attributes that cause the costs to be incurred by the utility. The salient allocation data is then compiled, allocation proportions calculated, and costs allocated on that basis.

For example, the analyst may determine that peak demand on a substation drives substation capacity costs; gather demand information at the substation as part of a load study; and, allocate substation capacity costs among customer classes in proportion to class demand coincident with substation peak demand.

Q. Please discuss the practical application of the Filing Package's process for the functionalization of costs.

A. Some costs are associated with one business function and can be directly assigned to that function (e.g., the costs of transmission lines and switching stations directly assigned to the transmission function).

However, many costs are common costs that are incurred to support all business functions and cannot be directly assigned. Examples include general plant (i.e., administrative office space), intangible plant, administrative and general expenses, and tax expenses. For a large utility like CEHE, common costs are significant.

Q. Are there ratemaking policy concerns that arise from the functionalization process's role in determining the share of common costs that will be assigned to the transmission function versus other functions?

A. Yes. PURA § 36.003(a) requires that the Commission establish just and reasonable rates. PURA § 36.003(c)(3) states that a utility may not establish or maintain an unreasonable difference concerning rates between localities or between classes of service. These provisions are relevant to the allocation of costs between wholesale and retail rates, because different classes of customers are subject to these rates.

Common costs that are included in wholesale TCOS are "uplifted" to the ERCOT transmission grid. Some portion of the costs are then borne by all of the 123 load serving entities identified above, which includes most of the captive ratepayers in the State of Texas. In contrast, common costs that are assigned to the distribution, metering and customer service functions will be included in retail rates and borne exclusively by retail ratepayers in CEHE's service territory.

For example, above I identified the Company's DSP's share of the costs of the grid during 2019 as approximately 25%. This means that for every dollar in common costs assigned to the transmission function (and uplifted to the ERCOT grid), CEHE's retail customers will bear only 25 cents on the dollar in the form of ERCOT transmission payments.[32] However, the Company's retail customers will bear 100% of common costs assigned to other functions.

CEHE faces an incentive to uplift costs to the grid to minimize its retail delivery charges. Likewise, many parties to this proceeding who represent retail ratepayers also face an incentive to minimize costs to the retail customers they represent by uplifting of cost to the grid.

Commission Staff is a party in this proceeding that has an incentive to oppose the inappropriate uplifting of costs, consistent with the requirements that

[32] As a DSP, CenterPoint must pay approximately 25% of the costs of the transmission grid, which means 25% of each TSP's TCOS, including its own TCOS (in its role as a TSP).

rates be just and reasonable, based on cost, and consistent with PURA § 36.003(c)(3).

Q. Has the Commission recently expressed concern about a TDU's incentive to inappropriately shift costs onto the ERCOT transmission grid?

A. Yes. At an Open Meeting on October 26, 2017, the Commission stated:

> CHAIRMAN WALKER: … I am concerned, I guess, about having companies that have very low distribution returns and then very high transmission returns and the implications of that, because what that means is, as you-all know, that the ERCOT—rest of ERCOT ratepayers are subsidizing the local distribution customers, and I have a problem with that.[33]

In a memorandum in January 2018, the Commission re-iterated this concern, stating:

> As discussed at the open meeting on October 26, 2017, I had concerns with the subsidization between the distribution and transmission rates for [CEHE].[34]

Additionally, in Project No. 39548 the Commission amended its *Transmission & Distribution (TDU) Investor-Owned Utilities Rate Filing Package for Cost-of-Service Determination* ("Filing Package"). In its Order approving the amended Filing Package, the Commission stated:

> The commission notes its concern, however, that a TDU, as well as certain intervening parties, may face an incentive to seek functional assignments or allocations that inappropriately shift costs onto the transmission function (TRAN), as those costs are spread to customers outside the TDU's retail service territory and are collected from customers across the ERCOT grid.[35]

[33] Open Meeting Transcript at 26 (Oct 26, 2017).

[34] Open Meeting of January 25, 2018, Memorandum from Chairman DeAnn T. Walker to Commissioners Brandy Marty Marquez and Arthur C. D'Andrea at 2.

[35] *Project to Revise Rate Filing Package for Investor Owned Transmission and Distribution Utilities*, Project No. 39548, Order of Adoption at 32 (Nov. 19, 2015).

The concern was codified by the Commission when it approved amendments to General Instruction No. 11(b) to the Filing Package, including the addition of the following language:

> For ERCOT TDUs, for any costs assigned or allocation to the TRAN function, and for which such assignment or allocation is not explicitly allowed for in the Substantive Rules, the utility must present a comprehensive justification for assigning or allocating those costs to the TRAN function, and must present evidence to support any such assignment or allocation to the TRAN function.[36]

Q. What happens when costs are inappropriately shifted onto the grid?

A. An inappropriate cross-subsidy is introduced whereby wholesale customers in ERCOT are subsidizing CEHE's retail customers. This also distorts the competitive market by artificially inflating the cost of wholesale transmission service for all ERCOT ratepayers. Upon adoption of competition in Texas, the Commission expressed an interest in avoiding these kinds of subsidies, stating:

> CHAIRMAN WOOD: … the cost causation ought to totally drive this. We ought to be as pure as possible in these rates because if we will continue to perpetuate all these subsidies and cross-subsidization mistakes of the past in the future, that will, I think in the long term, hurt competition …
>
> COMM. WALSH: I think you're right.[37]

Cross-subsidies also introduce fundamental issues of fairness. Under a cross-subsidy, costs that are caused by one group of ratepayers are shifted onto and borne by a different set of ratepayers. For example, when CEHE purchases telecommunications services to support the advanced metering system in its service

[36] *Id.*, Filing Package at 9.
[37] Open Meeting Transcript at p. 120-121 (June 29, 2000).

territory, customers in Brownsville and Dallas should not be required to bear a share of the telecommunications expenses under the transmission charges assessed to their retail customers, as would occur if the costs were uplifted to the grid in this proceeding. Dallas's and Brownsville's customers do not receive any advanced metering services from CEHE, and those customers do not cause those costs to be incurred by the Company.

Q. Are there any other general policy concerns that arise when costs are uplifted to the grid?

A. Yes. Although uplifting costs to the grid may lead to an avoidance of charges for a utility's retail customers in the short run, if such an approach were adopted by all other TDUs in ERCOT, on the whole it would be expected to lead to increases to the all-in electric charges[38] for all retail ratepayers.

Q. Were it to become common practice, how could inappropriate uplifting of costs to the grid increase all-in electric charges for retail ratepayers throughout the State?

A. Costs that are uplifted to the grid are less likely to be scrutinized and challenged by intervening parties in rate proceedings, because they are spread across the ERCOT grid.[39] Staff would review the costs consistent with the public interest, but with Staff alone reviewing the costs there would be a greater likelihood that imprudent or unreasonable costs would pass undetected into wholesale rates and become part

[38] Generation, transmission, distribution, and retail services.

[39] Note that none of the over one hundred DSPs that will be subject to CEHE's wholesale transmission rate have intervened and filed testimony in this case.

of the costs of the grid. Less extensive review of common costs would be expected to result in excessive common costs on the grid, including costs that would have been disallowed if they had been more extensively reviewed.

Were the uplifting approach adopted by all TSPs, over time the excessive common costs on the grid could grow to the extent that CEHE's 25% share of the excessive costs (in the TCOS of all TSPs on the grid) would exceed the costs avoided by CEHE's retail customers by uplifting CEHE-specific common costs to the grid in this proceeding. Put differently, from the perspective of the Company's retail customers, avoidance of inappropriate uplifting of costs may increase retail distribution rates slightly, but, if applied consistently, would be expected to lower their transmission system charges over time by a greater amount.

No matter the specific impact on CEHE's retail customers, on the whole excessive costs on the grid would be expected to result in higher all-in electric charges for ERCOT ratepayers. Inappropriate uplifting of costs to the grid therefore represents poor ratemaking policy.

Q. How is inappropriate uplifting of costs to the grid avoided?

A. By diligently following the rate design rule[40] and adhering to cost causation in the functionalization of common costs.

Q. Which Company witness supports CEHE's functionalization analysis?

A. Kristie L. Colvin.

[40] 16 TAC § 25.234(a).

Q. Do you have adjustments to CEHE's functionalization to provide for a more cost-based assignment of common costs to wholesale transmission, consistent with the Filing Package, the rate design rule, and cost causation?

A. Yes. I recommend adjustments to the functionalization of Account 408.1 (Texas gross margins tax), Account 930.2 (miscellaneous general expense), and Unprotected Excess Deferred Income Taxes under Rider UEDIT.[41] Each adjustment is discussed below.

Functionalization of Texas Margins Tax

Q. What is Texas Margins Tax (or franchise tax)?

A. It is a privilege tax levied on entities doing business in Texas.

Q. How does CEHE incur Texas Margins Tax?

A. Based on revenues subject to the tax. The following table shows CEHE's calculation of its requested Texas Margins Tax expense:

Table BTM-1

Sales [i.e., revenues]	$2,565,502,948
Plus:	
Interest	1,685,520
Capital gain	4,812,394
Other income	69,249,823
Less:	
Ordinary loss	(184,131,413)
Bad Debts	(1,859,544)
Margin Subject to Tax	$2,455,259,728
Statutory tax rate	0.7500%
Current Texas Margin Tax	$18,414,448
Source: WP II-E-2a	

[41] *See* Section XIV - Rate Riders.

Q. As shown in the above table, what causes the Company's Texas Margins Tax expenses?

A. Revenues.

Q. What sources of revenues to CEHE are at issue in this proceeding and will generate revenues subject to Texas Margins Tax?

A. Wholesale transmission revenues and retail delivery revenues.

Q. How does CEHE collect wholesale transmission revenues and retail delivery revenues?

A. In this proceeding, CEHE's wholesale transmission rates and retail delivery rates will be set by the Commission.[42] After the rates are set, CEHE will collect revenues based on its sales (billing units) multiplied by its rates. Wholesale revenues will be wholesale transmission rates multiplied by ERCOT billing units.[43] Retail delivery revenues will be retail delivery rates multiplied by retail billing units.

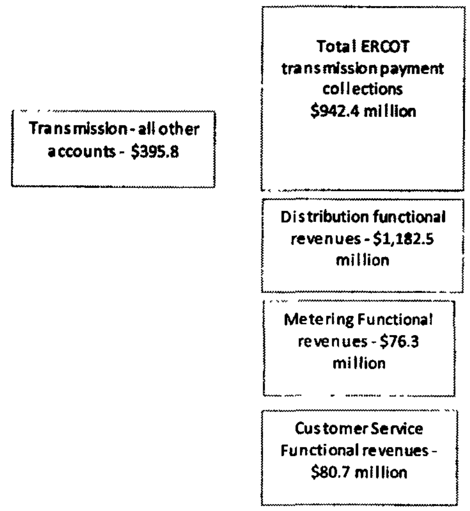
Texas Margins Tax will be levied on CEHE's revenues collected from each rate jurisdiction—wholesale and retail. A visual depiction of the Company's requested wholesale and retail base revenues is as follows:

[42] As explained above in the OVERVIEW section of my testimony, CenterPoint's wholesale transmission access rate will be set as its wholesale transmission revenue requirement divided by ERCOT billing units. Retail delivery rates will be set based on the share of the retail delivery requirement assigned to each rate class, under the system of charges designed for that class in the rate design phase.

[43] The Company will also collect some transmission export revenues for services provided to customers outside ERCOT.

Figure BTM-2 Requested Base Revenues

Requested Wholesale Transmission Base Revenues		Requested Retail Delivery Base Revenues		Requested Total Base Revenues



$395.8 million	+	$2282.2 million	=	$2,678 million
14.8%		85.2%		100.00%

The base-revenue figures can be found in the Company's application.[44]

Q. What is the relationship between "cost of service" and "revenue requirement"?

A. They refer to the two sides of the basic ratemaking formula:

Base Revenue Requirement = Cost of Service - Other Revenues

The two sides of the formula are set equal in a base-rate proceeding by setting base rates at a level that would fully recover the base revenue requirement. Costs that are approved for rate recovery are included in the base revenue requirement.[45]

[44] Application at 12, table "Summary of Revenues by Rate Class," column (b), "proposed revenues."
[45] Net of costs recovered outside base rates.

Q. Which functionalized costs are included in the wholesale transmission revenue requirement?

A. As shown above in Figure BTM-2, costs functionalized to transmission, excluding FERC Account 565 (net ERCOT transmission payments) are included in the wholesale revenue requirement and will drive the Company's wholesale revenues subject to Texas Margins Tax.

Q. Which functionalized costs are included in the retail delivery revenue requirement?

A. CEHE's total wholesale transmission charges incurred in its role as a DSP,[46] plus all the costs assigned to the distribution, metering, and customer service functions, will be included in the retail delivery revenue requirement and will drive retail base revenues subject to Texas Margins Tax.

Q. How does the Company propose to functionalize Texas Margins Tax expense?

A. The Company includes FERC Account 565 in its calculation of a "transmission function revenue requirement." It then allocates Texas Margins Tax expense to the transmission function based on the transmission function's calculated "revenue requirement." All the Texas Margins Tax assigned to the transmission function are then uplifted to wholesale TCOS.

Q. Do you support the Company's proposal?

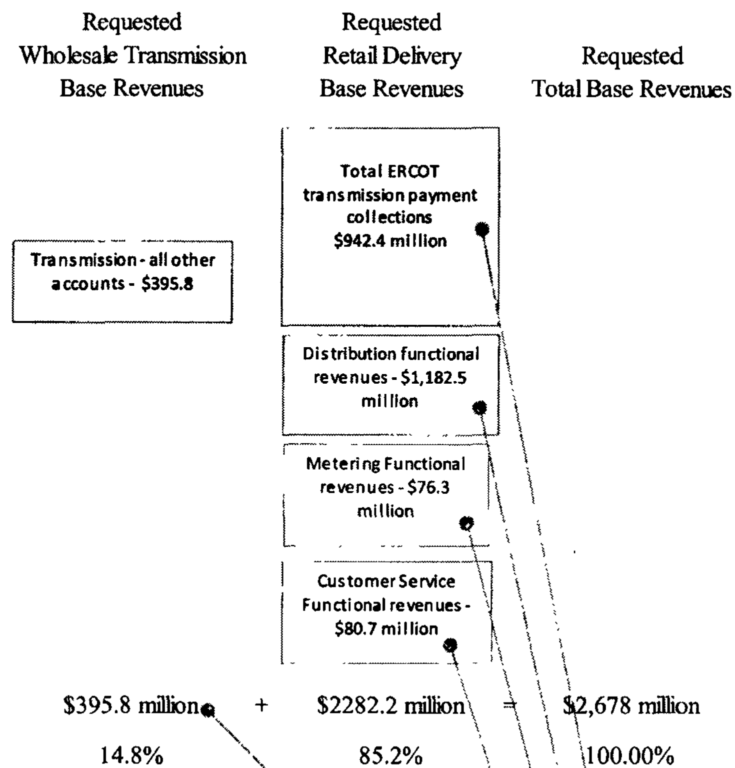
A. No. The Company's proposal is inconsistent with cost causation because CEHE's revenues associated with transmission system charges will be collected from the

[46] Which is equal to the total transmission functional revenue requirement shown in Schedule II-I TRAN, as presented by CenterPoint.

Company's retail customers under its retail rates, not its wholesale rates. Since the transmission system charge revenues will be collected from retail customers, the Texas Margins taxes levied on those revenues belong in the retail revenue requirement, not the wholesale revenue requirement (as proposed by CEHE).

The "transmission function revenue requirement" calculated by the Company ($942.6 million) is a much higher value that its requested wholesale transmission revenue requirement ($395.8 million). By using the higher revenue amount to functionalize Texas Margins Tax to wholesale, the Company over-allocates margins taxes to wholesale TCOS. A visual comparison of the Company's approach, which does not tie to its request, and Staff's approach, which ties to the CEHE's request as shown on page 12 of the Company's Application, can be seen below:

Figure BTM-3 Mapping CEHE's Requested Revenue Requirements to the Correct Functionalization of Texas Gross Margins Tax Expenses



Functional Cost of Service		CenterPoint's Approach			Correct Approach		
		Wholesale	Retail	Total	Wholesale	Retail	Total
Transmission	$-millions	No	$-millions	$-millions	$-millions	YES	
Account 565	546.7	546.7				942.6	942.6
Wholesale	395.9	395.8			395.8		395.8
Distribution	1,182.6		1,182.6	1,182.6		1,182.6	1,182.6
Metering	76.3		76.3	76.3		76.3	76.3
Customer Svc	80.7		80.7	80.7		80.7	80.7
Total	2,282.2	942.6	1,339.6	2,282.2	395.8	2,282.2	2,678.0
Allocation %	100.0%	**41.3%**	**58.7%**	**100.0%**	**14.8%**	**85.2%**	**100.0%**
Texas Margins Tax		8.3	11.7	20.0	3.00	17.00	20.0

The critical flaw in CEHE's approach is equating the transmission functional revenue requirement (which is a component of its *retail* cost of service) with its *wholesale* transmission revenue requirement.

Q. In defense of its proposal, CEHE states that the transmission function revenue requirement includes the cost of net ERCOT transmission payments.[47] How do you respond?

A. The transmission function's revenue requirement is part of the Company's retail delivery revenue requirement (i.e., ERCOT transmission payments), not its wholesale revenue requirement. The Company sets its retail rates to fully recover the transmission function's revenue requirement, including total ERCOT transmission payments. It is not appropriate to uplift the Texas Margins Tax expense associated with the Company's total ERCOT transmission payments (incurred to serve retail customers in its service territory) to wholesale TCOS (charged to wholesale customers across the grid).

Q. CEHE states that "the transmission function revenue requirement includes the cost of net ERCOT transmission payments...ERCOT transmission payments are an obligation of CEHE as a distribution service provider."[48] How do you respond?

A. CEHE has conceded that net ERCOT transmission payments in Account 565, which are functionalized to transmission, are nonetheless part of the charges to CEHE's *retail* customers. Nonetheless, CEHE proposes to charge *wholesale* customers for the Texas Margins Tax associated with FERC Account 565. The Company's admission undermines its proposal, but the Company did not change its flawed approach in its errata filing.

[47] CEHE's Response to Staff Seventh Set of Requests for Information at Response No. PUC07-12a.
[48] *Id.*

Q. The Company states that it believes it is appropriate to functionalize the Texas Margin Tax to the transmission function to match the tax with the underlying associated revenue requirement in the cost of service.[49] How do you respond?

A. To re-iterate, as presented by the Company, the transmission function's revenue requirement is part of CEHE's retail delivery revenue requirement (i.e., total ERCOT transmission payments), not its wholesale revenue requirement.

Q. The Company states that its approach "is also consistent with the functionalization factor that was approved in Docket No. 38339."[50] How do you respond?

A. The issue was not contested in Docket No. 38339.

Q. What do you recommend?

A. Consistent with cost causation, the rate design rule, and the requirement that rates be just and reasonable, I recommend that Texas Margins Taxes be functionalized in proportion to base revenues, as follows:

Table BTM-2 Wholesale-Retail Split of Texas Margins Tax

	Staff-adjusted Base Revenues[51]	Allocation Proportion
	a	$b = a / \sum a$
Wholesale	336,923,105[52]	13.3%
Retail	2,185,111,259[53]	86.7%
Total	2,522,034,365	100.0%

[49] *Id.*
[50] *Id.*
[51] Prior to re-allocation of Texas Margins Tax.
[52] Electronic workpapers to the Direct Testimony of Brian T. Murphy, workpaper "49421 - Staff's Model of CEHE's CCOSS.XLS," worksheet "III A-1 Wholesale TCOS," at Microsoft Excel cell H28.
[53] *Id.*, worksheet "I-A.1 to II-F," at Microsoft Excel cell G29, before adjustment to ERCOT transmission payments.

Q. Which accounts contain amounts associated with Texas Margins Tax?

A. The following three accounts:

- Account 182.3, Regulatory Assets-Margin Tax (rate base);
- Account 407.3, Texas Margin Tax - Docket No. 38339 (amortization expense); and,
- Account 408.1, Texas Gross Margin Tax (tax expense).

Q. How do you recommend that your adjustment be implemented in the cost study?

A. I recommend that the functionalization data that is used to calculate the TOTREV functionalization proportions be adjusted. To cure the Company's over-allocation of Texas Margins Taxes to wholesale transmission, retail delivery revenues associated with ERCOT transmission payments are re-allocated among the distribution, metering, and customer service functions in proportion to functional cost of service before the adjustment.

Q. What is the dollar impact of your recommendation?

A. Relative to CEHE's request, there is a downward adjustment to Texas Gross Margins Tax expense included in wholesale TCOS of approximately $5.7 million, and an upward adjustment to tax expense included in retail delivery cost of service of approximately $4.0 million. The downward adjustment is larger than the upward adjustment based on Staff's recommended disallowance sponsored by witness Filarowicz.[54] A comparison of Staff's and the Company's approaches can be seen in the following table:

[54] With respect to Accounts 182.3 and 407.3, there is no dollar impact as Staff witness Filarowicz has recommended disallowance of the full amounts. In the event Mr. Filarowicz' recommendation is not

Table BTM-3 Comparison of Staff's and CEHE's Functionalization of Account 408.1, Texas Gross Margins Tax expense

	CEHE's Requested Revenues		Functionalization Proportions - Texas Gross Margins Tax		Texas Gross Margins Taxes (thousands of dollars)	
	(millions of dollars) [55]	Share of Revenues	Staff[56]	Center-Point[57]	Staff	Center-Point
Wholesale Transmission	395.8	0.148	0.133	0.413	2,519	8,272
Retail Delivery:	2,282.2	0.852	0.867	0.587	16,338	11,755
Retail transmission	*942.6*	*0.352*	*0.000*	*0.000*	*0*	*0*
Distribution	*1,182.5*	*0.441*	*0.762*	*0.519*	*14,359*	*10,377*
Metering	*76.3*	*0.028*	*0.052*	*0.033*	*973*	*670*
Customer Service	*80.7*	*0.030*	*0.053*	*0.035*	*1,006*	*708*
Total	2,678.0	1.000	1.000	1.000	18,857	20,027

<u>Functionalization of Account 930.2 – Miscellaneous General Expense</u>

Q. What amount in Account 930.2, miscellaneous general expenses, is CEHE requesting?

A. $146.2 million.[58]

Q. How does the Company propose to functionalize Account 930.2?

A. CEHE functionalizes $141 million of the expenses (96.4%) in proportion to payroll expense excluding administrative and general payroll expense (PAYXAG).[59] The

adopted, approved amounts in Accounts 182.3 and 407.3 should also be functionalized in proportion to base revenues.

[55] Application at 12 [Bates 23] (Apr 5, 2019).

[56] Electronic workpapers to the direct testimony of Brian T. Murphy, workpaper "49421 – Staff's model of CEHE's CCOSS," worksheet "I-A.1 to II-F," at Microsoft Excel row 1261. Calculated using Staff-adjusted base revenues.

[57] Schedule II-F Func Factors.

[58] Schedule II-D-2 at Microsoft Excel cell H21.

[59] *See* "CEHE RFP Workpapers (redacted).XLS," worksheet "WP VI-L.2," at Microsoft Excel row 42. The allocation basis is payroll expense excluding administrative and general payroll expense (PAYXAG).

remaining amount of $5.2 million (3.6%) is directly assigned to the customer service function.[60]

Q. Has Staff recommended any adjustments to expenses in Account 930.2?

A. Yes. Staff witness Filarowicz recommends that $21.2 million in personnel-related expenses be disallowed.[61]

Q. Do you support the Company's functionalization approach?

A. In part, yes; but, not entirely.

With respect to the 3.6% portion of expenses directly assigned to customer service, I support the Company's approach. However, with respect to the $141 million portion of the expenses, I recommend a more granular approach that is more reflective of cost causation, which is appropriate given the magnitude of the expenses and the Filing Package instructions.

Q. What is your general criticism of CEHE's approach for the $141 million portion in Account 930.2 that was not directly assigned?

A. The Company used the last-resort functionalization basis provided in Schedule II-F of the Filing Package, "PAYXAG," instead of the more preferred approach. The Company's approach is not fully consistent with the nature of the different costs in the account.

PAYXAG would be an appropriate functionalization basis if all the expenses in Account 930.2 vary in proportion to payroll expense. As discussed

[60] *Id.* For the directly assigned amount, *see* Microsoft Excel cell D42. For the total amounts assigned to the customer service function, including $8.8 million in expenses functionalized to customer service on a PAYXAG basis, *see* Microsoft Excel cell L42.

[61] Direct testimony of Mark Filarowicz (June 12, 2019).

below, a significant share of the expenses do not vary in proportion to payroll expense.

Q. In its application, did CEHE provide an itemization of expenses?

A. Yes.[62] To facilitate a more granular functionalization of Account 930.2, I grouped the expenses into three categories using the expenses shown in the Trial Balance workpaper to the Company's Filing Package: (1) support services provided to CEHE's staff (e.g., finance, HR, legal, regulatory), (2) Technology Operations expenses, and (3) Telecommunications service expenses. The grouped expenses are as follows, and more detailed information can be found in my electronic workpapers:[63]

Table BTM-4 Grouping of Expenses in Account 930.2

Group	
1. Staff-adjusted Support Services to CEHE staff[64]	$79,242,055
2. Technology Operations expense in Account 930.2	$29,527,374
3. Telecommunications Services	$15,135,947
Staff-adjusted Account 930.2 in "Trial Balance" WP	$123,905,376
Source: Workpaper "CEHE RFP workpapers.XLS," at worksheet TB Year to Date.	

Q. With respect to the first group, support services to CEHE staff, how do you recommend that the expenses be functionalized?

A. For this component, I accept the Company's proposal to use PAYXAG as the functionalization basis. The costs are personnel-related, and PAYXAG is a payroll-based functionalization factor.

[62] Workpaper "CEHE RFP workpapers.XLS," at worksheet TB Year to Date.
[63] Electronic workpapers to the direct testimony of Brian T. Murphy at Workpaper WP_Acct 9302.
[64] As adjusted by Staff witness Filarowicz.

Q. With respect to the second group, Technology Operations expense, did CEHE describe the expenses?

A. Yes. An explanation of the services can be found in the testimony of Company witness Shachella James. Based on Ms. James' testimony and information provided by the Company in response to discovery, I classified the Technology Operations expenses as personnel-related and customer-related, as follows:

Table BTM-5 Classification of Technology Operations Services expenses (millions of dollars)[65]

Service	Personnel	Customer
Desktop Data Device[66]	18.684	
Mainframe CPU Utilization[67]		4.612
Data Management[68]		0.718
Distributed Systems[69]		37.814
Enterprise App Dev & Support	14.502	
App Dev & Support[70]		26.663
Telephony Service	2.503	
Telecom Add/Move/Change	0.145	
Data & Cyber Security Mgmt	3.895	
Subtotal	39.729	69.807
Share of Total	36.3%	63.7%

[65] Amounts were provided in the Company's response to Staff's Seventh Set of Requests for Information, at Response No. PUC07-13a.

[66] Direct Testimony of Shachella James at 20: Costs of this service are assigned based on number of employee log-in IDs.

[67] CenterPoint's response to Staff's Seventh Set of Requests for Information at Response No. PUC07-12b: "the primary systems requiring mainframe service include the Customer Information System, The Transaction Management Hub, SAP Enterprise Resource Planning, which receives customer usage and billing information, and the Customer Relationship Management System (CRM) System used to support customer interaction and customer requirements."

[68] *Id.*, at response no. PUC07-13b: "the data management service includes the Customer Relationship Management (CRM) and SAP databases containing generated customer information used for purposes of supporting electric customers ranging from general billing and customer related support services . . ."

[69] *Id.*, at response no. PUC07-14: "The mission critical distributed systems include Customer Relationship Management, SAP Enterprise Resource Planning [discussed in above footnote as customer-related], the Transaction Management Hub, the Meter Data Management system, and Advanced Distribution Management System."

[70] Direct Testimony of Shachella James at 20: "The charges are based upon billable hours of actual work effort required to support ongoing baseline operations activity …" From this description, this service was included among those in support of the critical business systems identified as customer-related in the above descriptions.

The share of Technology Operations services expense classified as personnel-related were functionalized on a PAYXAG basis (as requested by the Company for the entirety of Account 930.2); and, the share classified as customer-related were functionalized on the basis of total operations and maintenance expense excluding fuel and purchased power (TOMXFP), excluding the transmission function.

Q. With respect to the third group, telecommunications services expenses, did the Company provide any information in response to discovery?

A. Yes. The Company stated:

> None of the [telecommunications services] cost centers above [Tele Del - Wireless, Telecom Network, TELECOM SUPPORT, Telecomm Cell Relay, ADDR & MTR ROUTE, GIS BUSINESS SOL] are involved in the provision of wholesale transmission service.[71]

Accordingly, I recommend that the full amount be directly assigned to retail cost of service.

Q. How is your recommendation implemented?

A. A comparison of my recommended functionalization and the Company's approach can be seen in the following table:

[71] Response of CenterPoint Energy Houston Electric to Commission Staff's Twelfth Set of Requests for Information, at Response No. PUC12-04.

Table BTM-6 Functionalization of Account 930.2, Miscellaneous General Expense

Function	Allocation proportion		$s in thousands	
	CEHE	Staff	CEHE	Staff
Wholesale Transmission	0.1912	0.1356	27,953	16,956
Distribution	0.7115	0.7079	104,028	88,508
Metering	0.0018	0.0378	266	4,724
Customer Service	0.0955	0.1187	13,965	14,839
Total	1.0000	1.0000	146,212	125,027

As can be seen, the result is a downward adjustment to the Account 930.2 expenses included in wholesale TCOS of approximately $11 million.

VI. WHOLESALE TRANSMISSION COST OF SERVICE

Q. What is CEHE's Staff-adjusted wholesale TCOS?

A. The Company's Staff-adjusted wholesale TCOS is $336,923,105, which represents a decrease of $58,873,468 as compared to CEHE's requested wholesale TCOS in the amount of $395,796,573. A comparison of Staff's adjusted and CEHE's requested wholesale TCOS can be seen in the following table:

Table BTM-7 Comparison of CEHE's Requested and Staff's Recommended Wholesale Transmission Revenue Requirement (amounts in thousands of dollars)

	CEHE Request	Staff Adjustment	Staff-adjusted Wholesale TCOS
Operating and Maintenance Expenses	106,519	-16,110	90,409
Depreciation & Amortization Expenses	79,657	-1,686	77,972
Taxes Other Than Federal Income Tax	43,928	-6,458	37,470
Federal Income Tax	27,265	-9,258	18,007
Return on Invested Capital	174,743	-25,362	149,381
Minus: Other revenues	36,316	0	36,316
Wholesale TCOS	**395,797**	**-58,873**	**336,923**

VII. WHOLESALE TRANSMISSION RATES

Q. Please describe wholesale transmission rates.

A. There are two types of wholesale transmission rates: access fees for wholesale transmission service within ERCOT, and transmission service for delivery of power to be exported from ERCOT.

CEHE's annual access fee for transmission service within ERCOT is calculated as its TCOS divided by the ERCOT billing units most recently approved by the Commission.[72]

The transmission service rates for exports from ERCOT are seasonally differentiated. There is an on-peak rate which is effective during the months of June, July, August and September is equal to CEHE's annual access fee divided by four. There is also an off-peak rate which is effective during all other calendar months and is based on the Company's annual access fee divided by twelve.[73]

Q. Please set forth CEHE's wholesale transmission rates consistent with Staff's recommendations.

A. Shown in the following table:

Table BTM-8 Wholesale Transmission Rates

	CEHE Requested[74]	Staff Recommended	Billing Basis
Annual access fee	\$5.7056723	\$4.8569719	per kilowatt of ERCOT AVG 4CP demand
Monthly On-Peak Export Rate	\$1.426418	\$1.214243	per kilowatt-month
Monthly Off-Peak Export Rate	\$0.475473	\$0.404748	per kilowatt-month

[72] 16 TAC § 25.192(b)(1).
[73] 16 TAC § 25.192(e)(2).
[74] Exhibit MAT-10.

Q. Does Staff's adjustment to wholesale TCOS have a flow-through effect on the Company's retail cost of service?

A. Yes. As stated above, for every dollar that goes into CEHE's wholesale TCOS, CEHE's retail customers will bear approximately 25 cents on the dollar in their retail rates in the form of ERCOT transmission payments. Conversely, every dollar removed from wholesale TCOS results in 25 cents in avoided ERCOT transmission payments for CEHE's retail customers.

Q. What are CEHE's ERCOT transmission payments consistent with Staff's recommended wholesale TCOS?

A. CEHE's ERCOT transmission payments consistent with Staff's recommended wholesale TCOS amounts to $927,700,584, which represents a downward adjustment of $14,702,361 as compared to CEHE's requested ERCOT transmission payments in the amount of $942,402,945.[75]

Q. Have you implemented the adjustment in developing Staff's recommended wholesale and retail cost of service?

A. Yes. The correct amount of ERCOT transmission payments to be borne by each class can be seen in "WP_ERCOT pmt" in Staff's cost study, included in my electronic workpapers.

[75] The calculation is: (CenterPoint's DSP Avg 4-CP ÷ ERCOT Avg 4-CP) x Staff's downward adjustment to TCOS = (17,323,382.3 ÷ 69,368,963.5) x $58,873,468 = $14,702,361.

VIII. RETAIL CLASS COST ALLOCATION

Q. Switching from the wholesale to the retail side of CEHE's business, what is CEHE's overall retail delivery cost of service consistent with Staff's adjustments?

A. CEHE's Staff-adjusted retail delivery cost of service is $2,170,408,898,[76] which represents a downward adjustment of $111,795,782 as compared to the Company's requested retail delivery cost of service of $2,282,204,680.[77]

Q. What is a class cost of service study?

A. Once the overall retail delivery cost of service has been determined, the amount for each line item and function must be allocated based on cost causation among rate classes. The end result of the study is the best approximation of the Test Year costs incurred by the Company to serve each rate class. The best approximation of class cost of service is then used in the rate design phase for each retail rate class, as rates for each class are designed to recover the costs caused by that class, as measured in the study.

Q. Which Company witness supports the Company's class cost of service study?

A. Matthew A. Troxle.[78]

Q. Do you recommend any adjustments to the Company's proposed class allocation?

A. Yes.

[76] Retail cost of service before the adjustment to ERCOT transmission payments ($2,185,111,259 from worksheet "I-A.1 to II-F" to Staff's cost study) minus Staff's adjustment to ERCOT transmission payments ($14,702,361 as shown in worksheet "WP_ERCOT pmt" to Staff's cost study).

[77] Net of other revenues and wholesale revenues.

[78] Direct Testimony of Matthew A. Troxle at 14.

Allocation of ERCOT transmission payments.

Q. Above you discuss how CEHE's retail customers are charged for use of the ERCOT transmission system under the "transmission system charge" component of base rates. How does the Company propose to allocate ERCOT transmission payments among classes for the purpose of setting its transmission system charges?

A. In proportion to peak demand on its distribution system during the summer months, measured at meter.[79]

In reference to his proposed approach in direct testimony, Company witness Troxle inaccurately states: "CenterPoint Houston proposes to use the unadjusted 4CP allocation factor based on the *ERCOT* peak summer month periods to allocate capacity-related transmission costs."[80] In the Company's errata filing, Mr. Troxle corrects his statement by changing "ERCOT" to "CEHE,"[81] confirming the Company's proposed use of CEHE's distribution demands, not ERCOT 4CP demands.

Q. Do you support the Company's proposal?

A. No. The Company's proposal is inconsistent with cost causation, with the Commission's rules, and with Commission precedent, including the Commission's decision in Docket No. 38339, CEHE's last base-rate case, which was fully litigated

[79] Schedule II-H-1.3 at Microsoft Excel rows 148-151.
[80] Direct Testimony of Matthew A. Troxle at 20.
[81] Errata 1 at Bates 20 (May 20, 2019).

and wherein CEHE's class allocation of ERCOT transmission payments was a contested issue.

Q. What causes CEHE to incur ERCOT transmission payments?

A. The Company's retail load that is coincident with ERCOT peak load during the months of June, July, August, and September, which is identified earlier in my testimony as "DSP Avg 4-CP."

Q. What causes CEHE's DSP Avg 4CP?

A. Class load imposed on CEHE's system at the time of the ERCOT peak load, measured at source. Put differently, DSP Avg 4CP load is an aggregation of class load coincident with ERCOT 4-CP load. Class load coincident with ERCOT 4-CP causes CEHE to incur ERCOT transmission payments.

Q. How does CEHE's proposal deviate from class load coincident with ERCOT 4CP?

A. The Company is using class loads at the time of the peak of its *distribution* system, which does not peak at the same time as the ERCOT transmission grid. During the Test Year, CEHE's distribution system peaked at 4:16 pm on Wednesday, August 22rd. However, the ERCOT transmission system peaked at 4:45 pm on Thursday, August 23rd.[82]

Class loads at the time of the peak of CEHE's distribution system are not the same as loads coincident with ERCOT 4CP, and do not drive the Company's

[82] CenterPoint's Responses to Staff's First Set of Requests for Information at Response No. PUC01-14 (May 2, 2019).

ERCOT transmission payments. The Company's proposal is inconsistent with cost causation.

Q. Do the Commission rules provide that ERCOT transmission payments be assessed on the basis of ERCOT 4CP?

A. Yes. 16 Texas Administrative Code (TAC) § 25.192 (d) provides:

> (d) Billing units. No later than December 1 of each year, ERCOT shall determine and file with the commission the current year's average 4CP demand for each DSP, or the DSP's agent for transmission service billing purposes, as appropriate, excluding the portion of coincident peak demand attributable to wholesale storage load. This demand shall be used to bill transmission service for the next year. The ERCOT average 4CP demand shall be the sum of the coincident peak of all of the ERCOT DSPs, excluding the portion of coincident peak demand attributable to wholesale storage load, for the four intervals coincident with ERCOT system peak for the months of June, July, August, and September, divided by four. As used in this section, a DSP's average 4CP demand is determined from the total demand, coincident with the ERCOT 4CP, of all customers connected to a DSP, including load served at transmission voltage, but excluding the load of wholesale storage entities. The measurement of the coincident peak shall be in accordance with commission-approved ERCOT protocols.

CEHE's proposed use of distribution peak loads is not consistent with the Commission's Rules.

Q. Was CEHE's class allocation of ERCOT transmission payments a disputed issue in Docket No. 38339, CEHE's last fully litigated base-rate proceeding?

A. Yes. In the Proposal for Decision, referring to the ERCOT 4-CP, the ALJs found:

> **4CP Transmission Cost Allocation Factor**
> For the Transmission Cost Allocation Factor, the four coincident peak (4CP) methodology should be used, but CEHE's proposed adjustments for weather, the number of year-end customers, and the

use of 15-minute demands rather than hourly demands should be rejected.[83]

The Commission adopted the PFD, and found in its Order on Re-Hearing, again, referring to the ERCOT 4CP:

FoF 176 The use of 4CP is consistent with cost causation.

FoF 177 CenterPoint's proposal to use adjusted 4CP is inappropriate and should not be adopted

In Docket No. 38339, the Commission rejected adjustments to the 4CP data for use in the allocation of ERCOT transmission payments. In this proceeding, the Company has proposed a more significant deviation—abandonment of ERCOT 4CP in favor of CEHE's distribution peak loads.

Q. Has ERCOT 4CP been adopted as the class allocation basis for ERCOT transmission payments in all litigated base-rate proceedings since unbundling?

A. Yes. The use of ERCOT 4CP was adopted in Docket Nos. 28840,[84] 33309, 35717, and 38339.

Q. Did CEHE present any arguments in support of its proposal to deviate from cost causation and from the Commission's rules and precedents?

A. No, not to my knowledge.

[83] *Application of CenterPoint Electric Delivery Company, LLC for Authority to Change Rates*, Docket No. 38339, Proposal for Decision at 8 (Dec 3, 2010).

[84] *Application of AEP Texas Central Company for Authority to Change Rates*, Docket No. 28840, Final Order at FoF 246 (Aug 15, 2005).

Q. Does the use of ERCOT 4CP instead of CEHE's 4CP harm the Company in any way?

A. No. The Company will collect the same revenue requirement. The adjustment simply changes the allocation of costs among classes.

Q. What do you recommend?

A. I recommend rejection of the Company's proposal. I recommend that ERCOT transmission payments be allocated among classes in proportion to ERCOT 4CP demand at source, consistent with cost causation and Commission precedent.

Q. Please provide a comparison of CEHE's requested and Staff's recommended class allocation of ERCOT transmission payments.

A. As follows:

Table BTM-9 Class Allocation of ERCOT transmission payments

	Allocation %		Thousands of dollars	
Class	CEHE	Staff	CEHE	Staff
Residential	0.4665	0.4761	439,639	441,675
Secondary Small	.0088	0.0083	8.277	7,745
Secondary Large	0.3407	0.3469	321,039	321,784
IDR	na	0.1369	126,697	127,000
Non-IDR	na	0.2099	194,342	194,784
Primary	0.0348	0.0341	32,837	31,630
IDR	na	0.0310	30,003	28,780
Non-IDR	na	0.0031	2,833	2,850
Transmission	0.1492	0.1346	140,611	124,866
Lighting	0.0000	0.0000	0	0
TOTAL	1.0000	1.0000	942,403	927,700

Summary of Class Cost of Service

Q. What is each class's cost of service consistent with Staff's adjustments?

A. Class cost of service consistent with Staff's adjustments can be seen in the following table:

Table BTM-10 Class Cost of Service (thousands of dollars)

Class	CEHE[85]	Staff[86]
Residential	1,217,815	1,164,020
Secondary Small	30,607	28,898
Secondary Large	739,867	710,523
Primary	70,090	66,283
Transmission	162,434	146,540
Lighting - SLS	58,265	51,458
Lighting - MLS	3,127	2,687
TOTAL	2,282,205	2,170,409

This concludes the cost allocation process.

IX. RETAIL CLASS PRESENT BASE REVENUES

Q. With the conclusion of cost allocation, is it possible to ascertain if CEHE's present base revenues under current rates are sufficient to recover its costs and grant the Company a reasonable opportunity to earn a fair return for shareholders?

A. No. Before such a determination can be made, it is necessary to calculate the Company's present retail base revenues and compare that level of revenues to the Company's retail cost of service.

[85] Direct Testimony of Matthew A. Troxle at 2.

[86] Electronic workpapers to the Direct Testimony of Brian T. Murphy, Staff's model of CenterPoint's class cost of service, at worksheet CCOSS Summary.

If CEHE's present revenues exceed its costs, the Company has a revenue surplus and its rates must be lowered. If present revenues are less than cost of service, the Company has a revenue shortfall and rates must be increased on an overall basis to grant the Company a reasonable opportunity to recover its costs and earn a fair return for its shareholders.

Q. Which Company witness sponsors the Company's calculation of present base revenues?

A. Matthew A. Troxle.[87]

Q. Has Staff recommended any adjustments to CEHE's determination of present base revenues?

A. Yes. Staff has two adjustments:

1. Staff witness Alicia Maloy recommends adjustments to CEHE's weather normalization of billing units, which is an input to the calculation of present base revenues.[88]
2. Staff witness William Abbott recommends rejection of CEHE's annualization of estimated energy savings that the Company claims is necessary to account for energy-efficiency measures implemented during the Test Year, which is also an input to the calculation of present base revenues.[89]

[87] Direct Testimony of Matthew A. Troxle at 25.
[88] Direct Testimony of Alicia Maloy on behalf of Commission Staff (June 12, 2019).
[89] Direct Testimony of William Abbott on behalf of Commission Staff (June 12, 2019).

Q. Company witness Troxle refers to "billing determinants"[90] and you refer to "billing units." What is the difference?

A. None. For the purpose of this discussion, the terms are synonymous.[91]

Q. Have you calculated the Company's present base revenues consistent with Ms. Maloy's and Mr. Abbott's recommendations?

A. Yes. CEHE's Staff-adjusted present base revenues are $2,129,484,979,[92] which is 1.6% greater on a percentage basis than the Company's calculation of present base revenues, which are $2,095,600,469.[93] The supporting calculations can be found in my electronic workpapers.[94] The adjusted billing units are also used in rate design.

Q. What effect does an increase to present base revenues have on the Company's request?

A. Increasing present base revenues has the effect of decreasing the amount of revenue increase that otherwise would have been necessary to close the gap between present revenues and the revenue requirement. Put differently, it has the same effect on rates as a disallowance of costs.

[90] Direct Testimony of Matthew Troxle at 8 (Apr 5, 2019).

[91] In some contexts, "billing units" may refer to actual sales and "billing determinants" may refer to the specific billing units that are used to set rates, as a subset of "billing units."

[92] Electronic workpapers to the Direct Testimony of Brian T. Murphy, workpaper Present Revenue Adjustments.

[93] Application at 12, table showing Retail Delivery Present Base Revenues.

[94] Electronic workpapers to the Direct Testimony of Brian T. Murphy, workpaper Present Revenue Adjustments.

Q. Have you calculated CEHE's retail revenue differential?

A. Yes. Subtracting CEHE's retail base revenue requirement of $2,171,408,898 from its retail present base revenues of $2,129,484,979 results in a revenue shortfall of $40,923,919. On an overall basis, CEHE's retail base revenues must be increased by $40,923,919, or 1.9% on a percentage basis, to grant CEHE a reasonable opportunity to recover its retail costs and earn a fair return for shareholders.

In comparison, in this proceeding CEHE requests retail base revenues of $2,282,204,680, which represents a requested increase of $186,603,209, or 8.9% on a percentage basis, over present base revenues of $2,095,600,469.[95]

The effects of Staff's adjustments can be seen in the following table:

Table BTM-11 Retail Base Revenue Differential

	CenterPoint	Staff
Present Retail Base Rev	2,095,600,469	2,129,484,979
Retail Base Revenue Requirement	2,282,203,678	2,170,408,898
Retail Base Revenue Differential	186,603,209	40,923,919
Source:	DT Troxle at 2	

X. OVERALL BASE REVENUE CHANGE

Q. On an overall basis, what change in base revenues is supported by Staff's analysis?

A. On an overall basis, Staff finds that the Company's revenues must be decreased by $11,120,997, calculated as follows:

[95] Does not reflect the Rider UEDIT credit.

Table BTM-12 Staff's Recommended Overall Change in Revenues

	Present Base Revenues-$s	Base Revenue Requirement-$s	Change-$	Change-%
Wholesale transmission	388,968,021	336,923,105	-$52,044,916	-13.4
Retail Delivery	2,129,484,979	2,170,408,898	+$40,923,919	+1.9
TOTAL	2,518,453,000	2,507,332,003	-$11,120,997	-0.5

XI. RETAIL CLASS REVENUE DISTRIBUTION

Q. Proceeding with the retail analysis, for each rate class, what is the difference between cost of service and revenue requirement?

A. A class's cost of service is the level of costs caused by that class during the Test Year, as measured in the cost study. A class's revenue requirement is the amount that a class's rates are set to recover. The step in ratemaking that determines the share of revenues to be recovered from each class is referred to as "revenue distribution."

Q. Why not just set each class's revenue requirement equal to its cost of service?

A. From the standpoint of economic efficiency, fairness, and revenue stability, that is the best approach. However, in some instances, a class may be too far away from cost of service under current rates; and, to close the gap in one step would promote rate shock.[96]

If it is determined that setting revenues directly to cost would promote an unacceptable degree of rate shock for one or more classes, the revenue increase assigned to one or more classes may be mitigated to decrease the likelihood of

[96] This can happen when a utility's cost structure or customer demographics change over time, or if inter-class subsidies were inadvertently introduced when current rates were set.

undue rate shock. This kind of approach to revenue distribution is referred to as "gradualism."

Gradualism should be performed reluctantly and sparingly because under a gradualist approach rates are set with the understanding that some of the costs that were caused by one group of customers will be shifted onto and borne by a different group of customers, which raises fundamental issues of fairness.

For an ERCOT utility like CEHE, gradualism also introduces competitive market distortions by altering the pass-through charges, and by extension the total price offerings, for all retail electric providers in the Company's service territory. Avoiding harm to the competitive market has been a component of Commission policy since the inception of the market. As mentioned previously in my testimony, during the transition to competition in 2000, the Commission stated:

> CHAIRMAN WOOD: ... the cost causation ought to totally drive this. We ought to be as pure as possible in these rates because if we will continue to perpetuate all these subsidies and cross-subsidization mistakes of the past in the future, that will, I think in the long term, hurt competition ...
>
> COMM. WALSH: I think you're right.[97]

Q. Based on Staff's analysis, please show how far each class is from cost under current rates by comparing that class's cost of service to that class's present revenues.

A. Each class's distance from cost under current rates can be seen in the table below. The Company's calculated distances from cost are shown for comparison purposes:

[97] Open Meeting Transcript at p. 120-121 (June 29, 2000).

Table BTM-13 Class distance from cost under current rates (in thousands of dollars)

	CEHE			Staff		
Class	Present Revenue	Cost of Service	Change (%)	Present Revenue	Cost of Service	Change (%)
Residential	1,130,553	1,217,815	7.7	1,164,264	1,164,020	0.0
Secondary Small	32,595	30,607	-6.1	32,768	28,898	-11.8
Secondary Large	654,965	739,867	12.9	654,965	710,523	8.5
Primary	66,701	70,090	5.1	66,701	66,283	-0.6
Transmission	143,212	162,434	13.4	143,212	146,540	2.3
Lighting - SLS	63,730	58,265	-8.6	63,730	51,548	-19.1
Lighting - MLS	3,844	3,127	-18.7	3,844	2,687	-30.1
TOTAL	2,095,600	2,282,205	8.9	2,129,485	2,170,409	1.9

Q. What is the Company's proposed approach to class revenue distribution?

A. The Company proposes to set revenues at cost for all classes, stating:

> Q. ARE ALL RATE CLASSES "IN UNITY"?
> A. Yes, as shown in Schedule II-I-Class Allocation Summary, the proposed delivery system charges for all rate classes were developed using cost causation principles, and thus eliminated interclass revenue subsidies so that the relative rates of return are equalized.[98]

Q. What does it mean for all rate classes to be "in unity?"

A. It refers to a conceptualization of a class's distance from cost under which each class is viewed as an investment, and the discussion is framed in terms of a class's financial performance relative to the system as a whole. This is done by indexing the rate of return provided by a class to the overall rate of return provided by the system. The indexed value is referred to as a class's "relative rate of return" and is equal to that class's rate of return divided by the rate of return provided by the system.

[98] Direct Testimony of Matthew A. Troxle at 27.

When revenues are set to cost for all classes, each class is providing a rate of return that is equal to the system average rate of return; each class's relative rate of return will be 1.0; and, this condition is referred to as "unity."

Q. Do you support the Company's proposal to set revenues at cost (i.e., unity)?

A. Yes.

Q. Would setting revenues directly to cost promote rate shock in this proceeding?

A. No. Gradualism is not necessary in this proceeding. The largest increase to a single class, 8.5% for the Secondary-Large class, is moderate and does not promote rate shock. Even at the Company's requested level of revenues, the largest increase to a class is 13.4%, which does not promote rate shock.

It important to keep in mind that the retail delivery charges to a customer typically represent about one-half of the customer's total electric charges.[99] In Docket No. 40443, a base-rate case for a vertically integrated utility to determine customers' all-in electric charges, the Commission found that an increase of 29% for a class did not warrant rate moderation.[100] In this proceeding, the highest increase to a class is well below that level.

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[99] The customer also receives generation services and retail services through the customer's retail electric provider.

[100] *Application of Southwestern Public Service Company for Authority to Change Rates*, Docket No. 43695, Final Order at 9 (Feb. 23, 2016): "The Commission declines to adopt any gradualism adjustment in this proceeding. The Commission has often stated that one of its primary responsibilities in setting rates is ensuring those rates are to the greatest extent reasonable, consistent with cost causation. Further, as SPS conceded, the wisdom of a gradualism adjustment is affected by the size of the rate change. While there is no magic threshold at which a change in rates automatically justifies an aberration from basing rates on classes costs of service, in Docket 40443 the Commission determined that an increase as large as 29% did not warrant rate mitigation. Here, SPS's overall Texas retail revenue requirement will be decreased by less than 1% and class allocations based purely on each classes' cost of service will result in relatively srnall rate changes. All but one class will experience less than a 14% change to its base-revenue responsibilities. The largest change will be borne by Street Lighting customers, whose revenue responsibility will increase

Q. At what level do you recommend that revenues be set for each class?

A. To cost of service as shown above in Table BTM-10.

XII. RETAIL CLASS RATE DESIGN

Q. Have you calculated rates for each rate class consistent with Staff's recommendations?

A. Yes. Staff's recommended retail rates can be found in Attachment BTM-7.

XIII. RETAIL TARIFF PROVISIONS – LED LIGHTING

Q. Do you take issue with any of the Company's amendments to its retail tariff?

A. Yes. The Company has proposed to amend the tariff provisions under its lighting rate schedule,[101] as follows:

> The Company's standard Lamp type for all street lighting service installations and replacements is Light Emitting Diode (LED). A Retail customer's request for a non-standard Lamp type will be subject to the availability of the Lamp type in Company's inventory. The Company is no longer procuring non-standard Lamp types for its inventory.[102]
>
> ...
>
> Conversion to LED. Existing ~~mercury vapor installations~~ non-LED Lamps will be converted to their LED-equivalent at no cost to Retail Customer during the normal course of maintenance when individual lamps burn out. ~~Mercury vapor installations will be converted to high pressure sodium lamps or LED equivalents, depending upon the standard street light installation, as selected by the Retail Customer, for the area in which the mercury vapor light resides, at no upfront cost to the~~ unless Company and Retail Customer agree on ~~LED Street Lights At this time there is not an LED replacement option for all existing Lamp Types. The rate at which LED street lights are converted or installed will be at the sole discretion of the~~

24.28%. Thus, moving from classes' costs of service and mandating inter-class cost subsidization is not warranted in this proceeding."

[101] Exhibit MAT-9 at 101, Tariff rate schedule no. *6.1.1.1.6, Lighting Services (Street Lighting and Miscellaneous Lighting Services)*.

[102] Exhibit MAT-8 at 33.

> ~~Company, may be based upon~~ a ~~negotiated deployment~~ different conversion schedule.~~, and will reflect, at a minimum, the capital requirements associated with the project, any customer required contribution in aid of construction, the physical capability to replace/install the LED street lights, and the availability of manufacturers to supply the requested LED luminaires. LED street lights are an emerging technology with no established industry standard.~~[103]

The tariff revisions have the effect of significantly reducing customer choice with respect to lamp type. With respect to new installations and replacements of existing installations, LED lighting would be installed unless the customer requests a non-LED lamp type, and only then if the Company has the non-LED alternative on hand in its inventory.[104] Additionally, the Company would not replenish its current inventory of non-LED lamp types.[105]

Q. Please generally describe the Company's lighting service.

A. The Company provides street lighting services to municipalities, government agencies, real estate developers, and other entities that require street lighting services.[106] The lighting tariff includes a schedule of *street lighting* rates applicable to customers where the Company owns the installation, and a schedule of *miscellaneous lighting* rates applicable to customers who own part of the lighting installation.

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[103] Exhibit MAT-8 at 38.

[104] CenterPoint's response to Commission Staff's Third Set of Requests for Information at Response No. PUC03-15 (May 8, 2019): "The change requested is for the LED streetlight fixture to become the standard streetlight fixture in CenterPoint Houston's entire electric footprint. The approval of the current proposal would make the LED light CenterPoint Houston's streetlight standard, allowing **any** streetlight upon failure to be replaced with a LED streetlight fixture."

[105] *Id.*, at Response No. PUC03-12: "The Company is no longer procuring non-LED Lamp types for its inventory. As Non-LED lamp inventory levels decrease, the option for a retail customer to select a non-LED lamp may not be available over time."

[106] *Id.*, at 33.

Q. What are the cost impacts of the Company's proposal?

A. Based on the Company's analysis, multiple cost elements in the cost study are affected by the proposal.[107] However, generally speaking the Company projects that the LED installations will require higher upfront capital expenditures[108] but will lower operations and maintenance expenses.[109] According to the Company's projections, the proposal therefore represents a tradeoff between higher upfront costs and lower recurring costs.

Q. What are some of the differences between LED and non-LED lamp types that drive the cost impacts?

A. According to the Company's analysis, a high-pressure sodium (non-LED) lighting installation has a [redacted] useful life. However, the bulbs have a useful life of only [redacted] years (and must be replaced when they burn out).[110]

In contrast, an LED lighting installation is projected by the Company to have a 15-year useful life.[111] LED installations do not have "bulbs," and do not have component parts that can fail partially or require routine maintenance. LED

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[107] Flow-through effects in the cost study.

[108] CenterPoint's responses to Commission Staff's Third Set of Requests for Information at Response No. PUC03-09, Attachment LED Conversion Summary Presentation at 35 (May 8, 2019): "LED fixtures average 1 ½ to 3 times the cost of standard [High Pressure Sodium] fixtures ... Monthly fixture charge paid to [CenterPoint] will likely increase substantially."

[109] *Id.*, at Confidential Response No. PUC03-10, worksheet "LED DCF with recovery," at Microsoft Excel row 60, indicating ongoing O&M of [redacted].

[110] Id., at worksheet "Assumptions," Microsoft Excel cell D47: "HPS luminaires have a [redacted] life and bulbs have a [redacted] life LED bulbs cannot be replaced, thus failure of luminaire components requires luminaire replacement."

[111] CenterPoint's responses to Commission Staff's Third Set of Requests for Information at Confidential Response No. PUC03-10, worksheet "Assumptions," Microsoft Excel cell C50 (May 8, 2019).

lights fail totally and must be replaced with a new installation at the end of their useful life.[112]

Q. Does the Company project that its proposal will have an impact on its retail delivery system?

A. To my knowledge, no. Street lighting generally occurs off-peak, when the Company has idle capacity on its system. So, it seems plausible that the impact of the proposal on the Company's distribution capacity costs (e.g., substations, feeder lines, poles, transformers) and its assigned share of ERCOT transmission payments would be minimal.

Q. Has the Company projected any changes in the cost impacts in the future?

A. Yes. The Company expects that the upfront costs of LED lighting will decline over time as the technology matures,[113] and that conversely the costs of non-LED alternatives will continue to climb as inventories become depleted and the technology generally falls into disfavor.[114]

Q. Has the Company presented other expected benefits of its proposal that are qualitative and more difficult to quantify?

A. Yes. In information provided in response to discovery, the Company claims that LED lighting produces light of high quality.[115] The Company suggests that higher quality street lighting can reduce crime and promote a sense of safety and security

[112] *Id.*, at cell D47: "HPS luminiares have a [redacted] life and bulbs have a [redacted] life. LED bulbs cannot be replaced, thus failure of luminaire components requires luminaire replacement."

[113] *Id.*, at cell B10, "LED Materials Inflation."

[114] *Id.*, at cell B11, "HPS Materials Inflation."

[115] *See*, e.g., CenterPoint's responses to Commission Staff's Third Set of Requests for Information at Response No. PUC03-09, Attachment "LED Conversion Summary Presentation," at 16 (May 8, 2019),

in communities.[116] Additionally, the Company notes that LED lighting is more tightly focused where it is wanted and disperses less light pollution into the skyline as compared with non-LED lighting.[117]

Q. What communities does the Company serve and which represent the Company's current or potential street lighting customers?

A. In addition to the City of Houston, the Company serves 159 municipal communities.[118] Less than one-third of the communities are represented by an intervening party in this proceeding.[119]

Q. What would be the customer impact of the Company's proposal on the 160 municipal communities it serves?

A. The proposal eliminates customer choice. Each community would no longer have the discretion to choose its preferred lighting type. From a financial standpoint, the

[116] *Id.*, at 14.

[117] *Id.*, at 15.

[118] *See* CenterPoint's *Tariff for Retail Delivery Service, Sheet No. 2.2* at 1: Cities of Addicks, Aldine, Algoa, Alta Loma, Arcadia, Arcola, Bacliff, Bammel, Barker, Barrett, Bayou Vista (Village Of), Baytown, Beach City, Beasley, Bellaire, Big Creek, Blue Ridge, Boling, Bonney, Bonus, Booth, Brazos Country, Brookshire, Brookside Village, Bunker Hill, Burleigh, Cedar Bayou, Channelview, Chenango, Chesterville, Clear Lake Shores, Clodine, Cloverleaf, Clute, Coady, Cochran, Cove, Crabb, Crosby, Cypress, Damon, Danbury, Danciger, Decker Prairie, Deer Park, Dewalt, East Bernard, Egypt, El Lago, Fairchilds, Foster, Freeport, Fresno, Frydek, Fulshear, Galena Park, Galveston, Genoa, Glen Flora, Gulf Park, Guy, Hedwig Village, Highlands, Hillcrest Village, Hilshire Village, Hitchcock, Hockley, Houston Point, Huffman, Huffsmith, Humble, Hungerford, Hunters Creek, Iago, Iowa Colony, Jacinto City, Jamaica Beach Village, Jersey Village, Jones Creek, Juliff, Katy, Kemah, Kendleton, La Porte, Lake Jackson, Lakewood, Lane City, Lissie, Liverpool, Longpoint, Magnet, Magnolia, Manvel, McNair, Meadows, Missouri City, Mixville, Mont Belvieu, Moonshine Hill, Morgans Point, Nassau Bay, Needville, Newgulf, Oak Ridge North, Old River-Winfree, Orchard, Oyster Creek, Pasadena, Pattison, Pearland, Peters, Pine Island, Pinehurst, Piney Point Village, Pleak, Pledger, Prairie View, Quintana, Racoon Bend, Randon, Retrieve, Richmond, Richwood, Rose Hill, Rosenberg, Rosharon, San Felipe, San Leon, Sandy Point, Santa Fe, Satsuma, Seabrook, Sealy, Sheldon, Shoreacres, Simonton, South Houston, Southside Place, Spanish Camp, Spring, Spring Valley, Stafford, Stagecoach, Strang, Sugar Land, Surfside Beach Village, Tavener, Taylor Lake Village, Thompsons, Tiki Island, Tomball, Virginia Point, Waller, Wallis, Webster, West University Place, Westfield, Weston Lakes, and Wharton.

[119] Gulf Coast Coalition of Cities (39 members), Texas Coalition of Utility Companies (9 members), and City of Houston. Member counts do not reflect members added after Motions to Intervene were filed.

proposal would impose higher upfront and replacement lighting costs on customers in the short-term. The proposal would exert pressure on municipal budgets that may have been set based on expectations that lower-cost, non-LED lighting options would continue to be available.

Q. Are you concerned about the potential customer impacts of the Company's proposal?

A. Yes. The magnitude of the financial impacts of the proposal on lighting customers is unclear. The Company stated that it has not performed an analysis of the electric charges to its lighting customers based on a non-LED lighting installation versus an equivalent LED lighting installation, which would be required to quantify the customer impacts of the proposal.[120] It is not advisable to mandate a change in electric charges without a proper analysis of the customer impacts.

Q. From a financial standpoint, what is the value proposition to shareholders inherent in the Company's proposal?

A. The higher capital expenditures associated with LED lighting installations would become part of the Company's plant-in-service. In a future base-rate proceeding, and in interim DCRF rate proceedings between base-rate cases, the incremental

[120] CenterPoint's Responses to Commission Staff's Ninth Set of Requests for Information, at Response No. PUC09-04 (May 28, 2019): Q. Please provide an analysis comparing the all-in costs of CEHE's services to a lighting customer with a non-LED installation versus an equivalent LED installation ... A. An analysis comparing the all-in cost of a non-LED installation to an equivalent LED installation does not exist...

plant-in-service would be eligible for inclusion in rate base, and the Company would earn a return on it.[121]

With respect to expenses, the Company's base rates would be set in this proceeding based on its Test-Year level of operations and maintenance expenses, which included its installed base of non-LED lighting. The Company projects that its lighting-related operations and maintenance expenses will decline as a result of the use of LED lighting for new installations and replacements.[122] Since O&M expense are not eligible expenses under a DCRF, the Company's O&M expenses would be frozen in those proceedings, and between base-rate cases the base revenues associated with avoided O&M costs would be returned to shareholders.

Q. From an economic policy standpoint, is there anything inherently wrong with a utility implementing a program that results in avoided O&M costs and increased returns to shareholders in the near term until the next base-rate proceeding?

A. Not at all. In fact, such programs are incentivized under ratemaking in PURA.[123] However, the programs should not benefit shareholders to the significant detriment of ratepayers.

[121] *See*, e.g., CenterPoint's responses to Commission Staff's Third Set of Requests for Information at Confidential Response No. PUC03-10, worksheet "Recovery Revenues," at Microsoft Excel row 60 (May 8, 2019).

[122] *Id.*, worksheet "LED DCF with Recovery," at Microsoft Excel row 23: "Avoided HPS O&M."

[123] Regulatory lag is part of ratemaking under PURA. When a utility achieves cost efficiencies between rate cases, regulatory lag benefits shareholders.

Q. Has the Company performed an overall analysis of the long-term financial benefits of the program for customers?

A. Yes. The Company projects that the higher upfront costs of the program will pay back in [redacted] years,[124] which is the point at which the cumulative net present value of the benefits of the program (i.e., avoided costs) exceeds the cumulative net present value of the costs of the program.[125]

This is commonly referred to as a "payback period," and in my experience is a financial metric that is commonly used by managers to decide if a program is worthwhile from a financial standpoint before the project is undertaken.

Q. Based on the Company's projected payback period of [redacted] years, how would you characterize the financial performance of the proposed LED lighting program?

A. Exceedingly poor.

Q. What experience do you have with the use of payback periods to assess the financial performance of various types of projects?

A. From 1999 until 2000, I performed economic analyses for Xerox Corporation in support of the deployment of large-scale document management systems,[126] which included payback period and other financial metrics.

From 2001 until 2005, I worked as a financial analyst for Prodigy Communications Corporation, which was later acquired by SBC Communications

[124] CenterPoint's responses to Commission Staff's Third Set of Requests for Information, Confidential Response No. PUC03-10, worksheet "Summary," at Microsoft Excel cell B40 (May 8, 2019).

[125] *Id.*, at worksheet LED DCF w Recovery at Microsoft Excel cell Q45, Cumulative PV of Cash Flows.

[126] Customers included United States Army Corps of Engineers and Brown and Root.

Corporation (now AT&T). While in this role, I analyzed the financial viability of product placement opportunities for DSL and dial-up internet services. The most important metric for the investment decision was payback period.

From 2006 to 2009, I worked on special projects as a business analyst for the Texas Facilities Commission. While at TFC, I analyzed the financial performance of various construction proposals, including the installation by Austin Energy of a thermal storage system on the Capitol Complex's cooling loop, the financial viability of high performance building construction as an alternative building type for new State facilities, and offers to purchase State buildings and lease them back to the State. In this role, payback period was again the metric that was most often relied upon by management to assess the financial viability of a potential project.

From 2017 to 2018, I worked for Potomac Electric Power Company as a senior rate analyst. While at Pepco, I analyzed the financial performance of proposals to underground distribution feeders.

Q. In your experience, what payback periods have been considered acceptable versus unacceptable in management's decisions to pursue or reject a potential project?

A. In my experience, for-profit entities require a one- to two-year payback period on investments. In other words, the investment must go cash positive within 24 months. A for-profit entity may be willing to stretch the payback period to three years for an extraordinary project with tremendous profit potential.

In my experience, a not-for-profit entity is willing to entertain projects with a longer payback period, from five years up to 7 years or so. Part of the reason is that these entities may have access to capital at lower rates and do not have to answer to shareholders.

For all types of entities, in my experience a [redacted] payback period—such as associated with CEHE's LED lighting proposal—would be well above the acceptable limit for a project to merit consideration for implementation. In my experience, a proposed project with a payback period of that length would be rejected out of hand in the initial planning phases, would not be approved by management, and would never be implemented. In fact, in my experience a project with such an extreme payback period would never be presented to management for approval.

Simply put, the proposed LED lighting project represents exceedingly poor financial value for CEHE's lighting customers, based on CEHE's own analysis.

Q. Do you have any other concerns about the financial performance of the LED lighting program?

A. Yes. I am concerned about the risks associated with the program. In my opinion, there is an unacceptable likelihood that the program will not return financial gains to customers over any time period. The Company estimates a [redacted] useful life for an LED installation.[127] However, the estimate is shown with a [redacted] standard deviation.[128]

Q. What is a standard deviation?

A. In statistics, "standard deviation" is a measure of the degree of variation in an estimate or dispersion around that estimate. It expresses the extent to which an actual observation is likely to deviate from its estimated or expected value. An estimate with a high standard deviation is uncertain. In CEHE's analysis, the standard deviation around its estimated useful life of [redacted] represents [redacted] of the estimate, which means that the estimated useful life of an LED installation is uncertain.

Q. Based on CEHE's analysis with a [redacted] useful life at [redacted] standard deviation, what is the likelihood that an LED lighting installation will fail before year [redacted] (the payback period hurdle), and never yield any financial benefits over any time horizon?

A. Based on CEHE's own analysis, the likelihood that an LED lighting installation will fail before crossing the payback period hurdle is [redacted].[129]

[127] CenterPoint's responses to Commission Staff's Third Set of Requests for Information at Confidential Response No. PUC03-10, worksheet "Assumptions," Microsoft Excel cell C50 (May 8, 2019).

[128] *Id.*, at cell C51.

[129] CenterPoint's responses to Commission Staff's Third Set of Requests for Information at Confidential Response No. PUC03-10, worksheet "Assumptions," Microsoft Excel cells C53-C66: Sum cells C53-C65 and add seven-tenths of cell C66 = [redacted].

Q. Based on your review of the financial performance of the LED lighting proposal, what do you conclude?

A. From a financial standpoint, the proposal is highly undesirable and should be rejected.

Q. Do you have any concerns about the program from a regulatory standpoint?

A. Yes. I am concerned that by eliminating customer choice the proposal puts the Commission in the position of supplanting each municipality's jurisdiction over what type of lighting is appropriate for its community given its preferences and budget constraints. If the Commission approves the Company's request, the Commission will have made the lighting decision for all 160 communities in CEHE's service territory. Such transfers of jurisdiction are best considered within the context of a rulemaking project, in which each community may have a chance to be heard.

Q. Is there a logical flaw in the Company's proposal?

A. Yes. The Company has presented evidence that the switch from non-LED to LED lighting could be highly beneficial for customers. If this were true, there would be no need to mandate the switch. Customers would freely choose it, and under that scenario the Company would experience the same financial benefits as it would under a mandate.

Q. What is your recommendation?

A. I recommend rejection of the Company's proposal to eliminate customer choice with respect to LED or non-LED lighting installation. I recommend no revisions to the provisions under CEHE's lighting tariff that govern the customer's selection of lighting type. Customers who wish to choose LED options would still be able to do so without being forced to.

XIV. RATE RIDERS – FUNCTIONALIZATION OF RIDER UEDIT

Q. What is a rate rider?

A. A rider is a cost recovery mechanism under which a utility recovers a portion of its costs under a separate system of charges outside base rates. A credit back to customers may also be performed using a rate rider.

Q. Has the Company proposed any new rate riders?

A. Yes. The Company requests Rider UEDIT.

Q. What is Rider UEDIT?

A. Company witness Troxle states:

> The purpose of Rider UEDIT is to refund to customers the balance of unprotected excess deferred income taxes resulting from the Tax Cuts and Jobs Act of 2017 that changed the corporate federal income tax rate in 2018.[130]

Q. How does the Company propose to functionalize the UEDIT to be credited under Rider UEDIT?

A. The Company has directly assigned the full amount to retail cost of service, to be refunded to retail ratepayers in CEHE's service territory.[131]

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[130] Direct Testimony of Matthew A. Troxle at 45.

[131] *See* Direct Testimony of Matthew A. Troxle at 2. The full amount under Rider UEDIT is credited to retail delivery cost of service.

Q. Do you support the Company's proposed functionalization of UEDIT?

A. No. Some share of UEDIT is properly assigned to wholesale transmission. Company witness Pringle supports the Company's functionalization of income-tax related amounts.[132] In his testimony, Mr. Pringle states that

> Q. IS THE COMPANY CURRENTLY REFUNDING ANY UNPROTECTED EDIT?
> A. Yes. The Company is annually returning $5.1 million of unprotected transmission plant related EDIT (grossed-up to a regulatory liability of $6.5 million) [with footnote to Docket No. 48065, Final Order (Apr. 27, 2018)]. In addition, the Company is returning unprotected distribution plant related EDIT of $15.7 million, which grossed up and net of return equals $19.2 million annually [with footnote to Docket No. 48226, Final Order at Finding of Fact 33 (Aug. 30, 2018)]. Through the end of 2018, the Company has refunded $8.4 million of unprotected EDIT through these mechanisms. These refunds will continue until new rates go into effect.

Docket No. 48065 was a proceeding to set the Company's wholesale transmission rates, which will be updated in this proceeding. Docket No. 48226 was a DCRF proceeding. At the time of those proceedings, CEHE functionalized 24.5% of UEDIT to transmission ($5.1 million divided by $20.8 million) and 75.5% to distribution (the remainder). In this proceeding, the Company proposes to assign 0% of UEDIT to wholesale transmission, and 100% to retail delivery. The Company's proposal has the effect of transferring the entire remaining wholesale portion of the UEDIT credit approved in Docket No. 48065 to retail customers under Rider UEDIT.

[132] Direct Testimony of Charles W. Pringle at 2.

Q. Did the Company explain why it proposes to re-functionalize UEDIT by directly assigning the entire remaining unreturned balance to retail?

A. No, not to my knowledge.

Q. What do you recommend?

A. I recommend that UEDIT be functionalized among wholesale transmission and retail delivery using the Commission-approved amounts in Docket Nos. 48065 and 48226, as follows:

Table BTM-14 Functionalization of UEDIT

	Docket Nos. 48065 and 48226	Functionalization Proportion	Assigned amount of UEDIT
Wholesale transmission	5.1	0.2452	-$7,934,344
Retail Delivery	15.7	0.7548	-$24,424,319
	20.8	1.0000	-$32,358,663

Q. How do you recommend that each function's assigned share of UEDIT be returned to customers?

A. With respect to the retail portion, I accept the Company's proposal to refund the amounts under Rider UEDIT.

With respect to the wholesale portion, I recommend that the Company be ordered to create a new wholesale transmission service rate rider with a refund period of one year and include the rider in its compliance tariff filing to be reviewed by the Commission in the compliance phase.

XV. TRUE-UP OF INTERIM RATE RECOVERY

Q. What cost recovery mechanisms are available to CEHE to recover the costs of plant investments?

A. Plant investments may be included in the Company's requested rate base in a base-rate proceeding. Additionally, between base-rate proceedings the Company can request that transmission-related investments be included in interim updates of the Company's TCOS (Interim TCOS), and distribution-related costs can be included in a distribution cost recovery factor (DCRF) update.

The interim TCOS and the DCRF are both interim updates that reserve reasonableness and prudence determinations for plant investments until the next base-rate proceeding.

Q. Does Staff recommend any disallowances associated with plant investments that CEHE made during the ten-year period since its last base-rate case?

A. Yes. For example, Staff witnesses Ianni and Sweatman recommend disallowance of certain plant investments. Witness Karl Nalepa, appearing on behalf of the Office of Public Utility Counsel, also recommends certain plant disallowances.[133]

Q. Were any costs associated with the disallowed plant included in the Company's interim TCOS or DCRF rates?

A. Unknown.

[133] Direct Testimony of Karl J. Nalepa (June 6, 2019).

Q. In the event the Commission adopts the recommendations of Staff and other parties regarding plant disallowances, are there any issues that arise with respect to the amounts the Company has already recovered under interim rates?

A. Yes. Regarding interim updates of transmission rates, 16 TAC § 25.192(h)(2) provides:

> Reconciliation. An update of transmission rates under paragraph (1) of this subsection 1 shall be subject to reconciliation at the next complete review of the TSP's transmission cost of service, at which time the commission shall review the costs of the interim transmission plant additions to determine if they were reasonable and necessary. Any amounts resulting from an update that are found to have been unreasonable or unnecessary, plus the corresponding return and taxes, shall be refunded with carrying costs determined as follows: for the time period beginning with the date on which over-recovery is determined to have begun to the effective date of the TSP's rates set in that complete review of the TSP's transmission cost of service, carrying costs shall be calculated using the same rate of return that was applied to the transmission investments included in the update. For the time period beginning with the effective date of the TSP's rates set in that complete review of the TSP's transmission cost of service, carrying costs shall be calculated using the TSP's rate of return authorized in that complete review.

Regarding interim updates of distribution rates, 16 TAC § 25.243(f) provides:

> DCRF reconciliation. The commission shall reconcile investments recovered through a DCRF in the electric utility's next comprehensive base-rate proceeding to the extent such reconciliation did not already occur in a DCRF proceeding pursuant to subsection (e)(5) of this section. The reconciliation shall be limited to the issues of the extent to which the investments complied with PURA, including §36.053 and §36.058, and this section and were prudent, reasonable, and necessary. To the extent that the commission determines that the investments did not comply with PURA and this section or were not prudent, reasonable, and necessary, the electric utility shall refund all revenues related to the

> investments that it improperly recovered through rates, and shall also pay its customers carrying charges on these revenues. The carrying charges shall be determined as follows: For the time period beginning with the date on which over-recovery is determined to have begun to the effective date of the new base rates, carrying costs shall be calculated using the same rate of return that was applied to the investments in the DCRF proceedings that resulted in the over-recovery. For the time period beginning with the effective date of the new base rates, carrying costs shall be calculated using the electric utility's rate of return authorized in the comprehensive base-rate proceeding.

If plant that was included in an interim TCOS or DCRF is disallowed, it is necessary to perform an inquiry into whether any costs of the plant have been recovered under the Company's interim rates. As part of the true-up, the over-recovery will need to be precisely quantified and rates set to refund over-collections to ratepayers.

Q. Could the true-up be accomplished in the compliance tariff phase of this proceeding?

A. No. The true-up will require access to detailed plant records that are only in the Company's possession. During the number-running process in support of the compliance filing, number-running Staff is limited in its ability to communicate with the Company and other parties. Additionally, it will require time to develop a methodology to perform the true-up. The development of the true-up methodology will require the exercise of judgment of the type that parties normally have the opportunity to review and contest if necessary. For these reasons, it would not be practicable to perform the true-up in the compliance phase in this proceeding.

Q. What do you recommend to accomplish the true-up?

A. I recommend that, if any plant disallowances are approved by the Commission, a separate compliance proceeding be ordered to determine the exact refund amounts and the forms that any refund should take. This will allow parties an opportunity to review the true-up calculations in light of the Commission's Order in this proceeding.

XVI. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes.

Brian T. Murphy

Public Utility Commission of Texas
1701 North Congress Avenue
Austin, TX 78711-3326

REGULATORY EXPERIENCE:

Public Utility Commission of Texas, Rate Regulation Division
Senior Rate Analyst, Tariff and Rate Analysis Section
Employed: February, 2019 to present.

ReSolved Energy Consulting
Management Consultant
Employed: May, 2018 to January, 2019.

Potomac Electric Power Company
Senior Rate Analyst
Employed: March, 2017 to April, 2018

Public Utility Commission of Texas, Rate Regulation Division
Senior Rate Analyst, Tariff and Rate Analysis Section
Employed: October, 2010 to March, 2017.

Perform analysis of tariff filings, cost allocation, and rate design. Review tariffs of regulated utilities to determine compliance with Commission requirements. Analyze cost allocation studies and rate design issues for regulated electric utilities. Analyze policy issues associated with the regulation of the electric industry. Work on or lead teams in contested cases, reports, the development of market rules, and research concerning pricing and related issues. Prepare and present testimony as an expert witness on rate and related issues in docketed proceedings before the Commission and the State Office of Administrative Hearings.

EDUCATION:

1998	Baylor University, Waco, TX Master of Business Administration, concentration in finance.
1996	George Mason University, Fairfax, VA Bachelor of Science.
1989-91	University of Chicago, Chicago, IL Core Curriculum.

BUSINESS SKILLS:

1999	St. Charles Training Center, St. Charles, IL. Financial Modeling.

List of Testimony Filed at the Public Utility Commission of Texas:

Docket No. 49148—*Application of El Paso Electric Company for a Transmission Cost Recovery Factor*—April 23, 2019.

Docket No. 48439—*Review of Rate Case Expenses Incurred in Docket 48371*—April 15, 2019.

Docket No. 48401—*Application of Texas-New Mexico Power Company for Authority to Change Rates*—August 13, 2018 (direct) and August 28, 2018 (rebuttal).

Docket No. 48371—*Entergy Texas, Inc.'s Statement of Intent and Application for Authority to Change Rates*—August 1, 2018.

Docket No. 48322—*Application of El Paso Electric Company to Adjust its Energy Efficiency Cost Recovery Factor and Establish Revised Cost Cap*—July 27, 2018.

Docket No. 48422—*Application of AEP Texas, Inc. to Adjust its Energy Efficiency Cost Recovery Factor and Related Relief*—July 17, 2018.

Docket No. 48421—*Application of Oncor Electric Delivery Company LLC to Adjust its Energy Efficiency Cost Recovery Factor*—July 12, 2018.

Docket No. 45414—*Review of the Rates of Sharyland Utilities, L.P., Establishment of Rates for Sharyland Distribution & Transmission Services, L.L.C., and Request for Grant of a Certificate of Convenience and Necessity and Transfer of Certificate Rights*—March 7, 2017 (Direct), and March 16, 2017 (Cross-Rebuttal).

Docket No. 45524—*Application of Southwestern Public Service Company for Authority to Change Rates*—August 23, 2016 (Direct), September 7, 2016 (Cross-Rebuttal), and December 8 (Settlement).

Docket No. 46014—*Application of CenterPoint Energy Houston Electric, LLC to Adjust Its Energy Efficiency Cost Recovery Factor*—August 8, 2016.

Docket No. 45691—*Application of Southwestern Electric Power Company for Approval to Amend Transmission Cost Recovery Factor*—June 9, 2016.

Docket No. 44498—*Review of Rate Case Expenses Incurred by Southwestern Public Service Company and Municipalities in Docket No. 43695*—May 9, 2016.

Docket No. 44941—*Application of El Paso Electric Company to Change Rates*—December 18, 2015 (Direct) and January 15, 2016 (Cross-Rebuttal).

Docket No. 45084—*Application of Entergy Texas, Inc. for Approval of a Transmission Cost Recovery Factor*—November 24, 2015.

Docket No. 44698—*Application of Southwestern Public Service Company to Adjust its Energy Efficiency Cost Recovery Factor*— July 31, 2015 (Direct); and August 11, 2015 (Cross-Rebuttal).

Docket No. 43695—*Application of Southwestern Public Service Company for Authority to Change Rates*— May 22, 2015 (Direct); and June 8, 2015 (Cross-Rebuttal).

Docket No. 44496—*Application of Southwestern Electric Power Company for Approval to Amend its Transmission Cost Recovery Factor*— May 22, 2015.

Docket No. 42560—*Application of CenterPoint Energy Houston Electric, LLC for Approval of an Adjustment to its Energy Efficiency Cost Recovery Factor*—August 7, 2014.

Docket No. 42448—*Application of Southwestern Electric Power Company for Approval of a Transmission Cost Recovery Factor*—July 31, 2014.

Docket No. 42454—*Application of Southwestern Public Service Company to Adjust its Energy Efficiency Cost Recovery Factor*—July 11, 2014.

Docket No. 42042—*Application of Southwestern Public Service Company for Approval of a Transmission Cost Recovery Factor*—May 1, 2014.

Docket No. 41791—*Application of Entergy Texas, Inc. for Authority to Change Rates and Reconcile Fuel Costs*—January 17 (Direct), January 31 (Cross-Rebuttal), and April 4 (Supplemental), 2014.

Docket No. 41474—*Application of Sharyland Utilities, L.P. to Establish Retail Delivery Rates, Approve Tariff for Retail Delivery Service, and Adjust Wholesale Transmission Rate*—October 28 (Direct) and December 20, 2013 (Settlement).

Docket No. 41444—*Application of Entergy Texas, Inc. for Authority to Redetermine Rates for Energy Efficiency Cost Recovery Factor*—July 26, 2013.

Docket No. 40627—*Petition by Homeowners United for Rate Fairness to Review Austin Rate Ordinance No. 20120607-05*—February 14, 2013.

Docket No. 40443—*Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs*—December 17, 2012.

Docket No. 40295—*Application of Entergy Texas, Inc., for Rate Case Expenses Severed from PUC Docket No. 39896; SOAH Docket No. 473-12-2979*—November 6, 2012.

Docket No. 40020—*Application of Lone Star Transmission, LLC for Authority to Establish Interim and Final Rates and Tariffs*—June 28, 2012.

Docket No. 39590—*Petition of El Paso Electric Company for Approval to Revise Military Base Discount Recovery Factor Tariff, Pursuant to PURA § 36.354*—October 26, 2011.

Docket No. 39361—*Application of AEP Texas North Company to Adjust Energy Efficiency Cost Recovery Factor and Related Relief*—August 2, 2011.

Docket No. 39359—*Application of Southwestern Electric Power Company to Adjust Energy Efficiency Cost Recovery Factor and Related Relief*—July 29, 2011.

Docket No. 39360—*Application of AEP Texas Central Company to Adjust Energy Efficiency Cost Recovery Factor and Related Relief*—July 27, 2011.

List of Testimony filed at the Maryland Public Service Commission

Case No. 9472—*In the Matter of the Application of Potomac Electric Power Company for Adjustments to its Retail Rates for the Distribution of Electric Energy*—January 2, 2018 (Direct), February 5, 2018 (Supplemental Direct), and March 8, 2018 (Additional Supplemental Direct).

List of Testimony filed at the District of Columbia Public Service Commission

Formal Case No. 1150—*In the Matter of the Application of Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service*—December 19, 2017 (Direct), and February 9, 2018 (Supplemental Direct).

Summary of Staff-Adjusted Wholesale Transmission Base Revenue Requirement

PUBLIC UTILITY COMMISSION OF TEXAS

III-A-1 SUMMARY OF WHOLESALE TCOS
TEST YEAR ENDING 12/31/2015
DOCKET 49421

	1		2
Description	**CEHE REQUESTED** Wholesale Transmission	**STAFF ADJUSTMENTS**	**STAFF RECOMMENDED** Wholesale Transmssion
Operating and Maintenance Expenses	106,519	-16,110	90,409
Depreciation & Amortization Expenses	79,657	-1,686	77,972
Taxes Other Than Federal Income Tax	43,928	-6,458	37,470
Federal Income Tax	27,265	-9,258	18,007
Return on Invested Capital	174,743	-25,362	149,381
TOTAL TRANSMISSION COST OF SERVICE	432,113	-58,873	373,239
Minus: Other Revenues	36,316	0	36,316
TOTAL ADJUSTED REVENUE REQUIREMENT	**395,797**	-58,873	**336,923**
ERCOT 4-CP MW 2018			**69,368.964**
Wholesale Transmission Rate $/kW			**4.8569719**

Export On-Peak (kW)	
Monthly	1.2142430
Weekly	0.280210
Daily	0.040030
Hourly	0.001668

Export Off-peak (kW)	
Monthly	0.4047477
Weekly	0.093403
Daily	0.013343
Hourly	0.000556

Summary of Staff-adjusted Retail Delivery Base Revenue Requirement (before Staff's adjustment to ERCOT Transmission Payments)

Description	Company Requested	Staff Adjustment Company Requested	Staff-Adjusted Company Requested
Operating and Maintenance Expenses	1,162,987	9,144	1,172,131
Depreciation & Amortization Expenses	351,230	-8,652	342,578
Taxes Other Than Federal Income Tax	278,298	-4,417	273,881
Federal Income Tax	76,724	-25,170	51,554
Return on Rate Base	479,058	-67,998	411,060
TOTAL COST OF SERVICE	2,348,297	-97,093	2,251,203
Less: Other Revenues	66,092	0	66,092
TOTAL ADJUSTED REVENUE REQUIREMENT	**2,282,205**	**-97,093**	**2,185,111**

Summary of Staff-adjusted Retail Delivery Rate Base

PUBLIC UTILITY COMMISSION OF TEXAS

I-A-1 SUMMARY OF TEXAS RETAIL
TEST YEAR ENDING 12/31/2015
DOCKET 45414

	1	2	3
Description	Company Requested	Staff Adjustment Company Requested	Staff-Adjusted Company Requested
Original Cost of Plant	10,545,743	-45,130	10,500,613
General Plant (Excl. Comm. Equip.)	489,125	0	489,125
Communications Equipment	485,947	-14	485,933
Total Plant	11,520,815	-45,143	11,475,672
Minus: Accumulated Depreciation	-3,804,013	0	-3,804,013
Net Plant In Service	7,716,802	-45,143	7,671,659
Other Rate Base Items:			
CWIP	0	0	0
Plant Held for Future Use	1,121	0	1,121
Accumulated Provisions	-6,970	0	-6,970
Accumulated Deferred Federal Income Taxes	-893,165	0	-893,165
Materials & Supplies	109,729	0	109,729
Cash Working Capital	26,163	-2,296	23,867
Prepayments	190,380	0	190,380
Other Rate Base Items			
Customer Deposits & Advances	-417	0	-417
Regulatory Liabilities	-786,041	0	-786,041
Regulatory Assets	124,911	-19,627	105,284
Subtotal	-1,234,290	-21,923	-1,256,213
TOTAL RATE BASE	6,482,512	-67,067	6,415,446
Rate of Return	7.3900%	-0.9800%	6.4100%
RETURN ON RATE BASE	479,058	-67,828	411,230

Staff-Adjusted Class Allocation ERCOT Transmission Payments

Rate Class	CEHE Share of ERCOT TCOS	4CP Allocation Factor	Share of ERCOT Payments
Residential	$ 927,700,584	47.609637%	**$ 441,674,882**
Secondary <=10 KVA	$ 927,700,584	0.834927%	**$ 7,745,623**
Secondary >10 KVA	$ 927,700,584	34.686205%	**$ 321,784,129**
IDR	$ 927,700,584	13.689788%	**$ 127,000,245**
Non-IDR	$ 927,700,584	20.996417%	**$ 194,783,884**
Primary	$ 927,700,584	3.409482%	**$ 31,629,782**
IDR	$ 927,700,584	3.102263%	**$ 28,779,713**
Non-IDR	$ 927,700,584	0.307219%	**$ 2,850,069**
Transmission	$ 927,700,584	13.459749%	**$ 124,866,168**
Lighting - SLS	$ 927,700,584	0.000000%	**$ -**
Lighting - MLS	$ 927,700,584	0.000000%	**$ -**
Total	$ 927,700,584	100.000000%	**$ 927,700,584**

Summary of Class Retail Delivery Base Revenue Requirements (Thousands of Dollars)

Description	Residential	Secondary =< 10 kW	Secondary > 10 kW	Primary	Transmission	Lighting SLS	Lighting MLS	Total TX-Retail
Transmission	441,675	7,746	321,784	31,630	124,866	0	0	927,701
Distribution	607,541	13,220	367,123	31,423	17,674	49,094	2,424	1,088,499
Metering	51,809	3,737	14,613	2,800	3,495	0	0	76,454
Billing	na	na	na	na	na	na	na	0
A-Billing	na	na	na	na	na	na	na	0
T&D Customer Service	62,995	4,196	7,002	430	505	2,365	263	77,756
Base Revenue Requiremer	1,164,020	28,898	710,523	66,283	146,540	51,458	2,687	2,170,409

Class Distance from Cost Under Current Rates (Thousands of Dollars)

	CenterPoint			Staff		
Class	Present Revenue	Cost of Service	Change (%)	Present Revenue	Cost of Service	Change (%)
Residential	1,130,553	1,217,815	7.7	1,164,264	1,164,020	0.0
Secondary Small	32,595	30,607	-6.1	32,768	28,898	-11.8
Secondary Large	654,965	739,867	12.9	654,965	710,523	8.5
Primary	66,701	70,090	5.1	66,701	66,283	-0.6
Transmission	143,212	162,434	13.4	143,212	146,540	2.3
Lighting - SLS	63,730	58,265	-8.6	63,730	51,548	-19.1
Lighting - MLS	3,844	3,127	-18.7	3,844	2,687	-30.1
TOTAL	2,095,600	2,282,205	8.9	2,129,485	2,170,409	1.9

Summary of Staff-Recommended Retail Rates

CLASS	RATE CHARGES				
	CHARGES	Current Rate	CenterPoint PROPOSED	STAFF RECOMMENDATION	
RESIDENTIAL	CUSTOMER CHARGE	$ 1.62	$ 2.48	$ 2.40	per Meter per Month
	METERING CHARGE	$ 3.85	$ 1.95	$ 1.96	per Meter per Month
	TRANSMISSION SYSTEM CHARGE	$0.008439	$ 0.01508	$0.014478	per kWh
	DISTRIBUTION SERVICE CHARGE	$0.016489	$ 0.02268	$0.019915	per kWh
SECONDARY =<10 kW (Small)	CUSTOMER CHARGE	$ 1.61	$ 2.44	$ 2.36	per Meter per Month
	METERING CHARGE	$ 4.41	$ 2.11	$ 2.10	per Meter per Month
	TRANSMISSION SYSTEM CHARGE	$ 0.00444	$ 0.009020	$0.008340	per kWh
	DISTRIBUTION SERVICE CHARGE	$ 0.01222	$ 0.015510	$0.014234	per kWh
SECONDARY >10kW (Large)	CUSTOMER CHARGE				
	IDR	$ 65.83	$ 48.28	$ 45.99	per Meter per Month
	NON-IDR	$ 2.26	$ 3.22	$ 3.07	per Meter per Month
	METERING CHARGE - NON-IDR				
	IDR	$ 63.07	$ 79.91	$ 79.50	per Meter per Month
	NON-IDR	$ 18.82	$ 6.90	$ 6.86	per Meter per Month
	TRANSMISSION SYSTEM CHARGE				
	IDR	$ 2.23870	$ 4 05308	$ 4.06172	per NCP Kva
	NON-IDR	$ 1.43180	$ 2.71402	$ 2.71948	per 4CP Kva
	DISTRIBUTION SERVICE CHARGE	$ 3.05943	$ 4.83592	$ 4.47530	per Billing Kva
PRIMARY	CUSTOMER CHARGE				
	IDR	$ 76.73	$ 61.26	$ 57.94	per Meter per Month
	NON-IDR	$ 3.58	$ 4.83	$ 4.57	per Meter per Month
	METERING CHARGE - NON-IDR			$ -	
	IDR	$ 138.40	$ 198.72	$ 197.82	per Meter per Month
	NON-IDR	$ 181.35	$ 285.55	$ 284.24	per Meter per Month
	TRANSMISSION SYSTEM CHARGE			$ -	
	IDR	$ 2.15460	$ 3.94053	$ 3.77885	per NCP Kva
	NON-IDR	$ 1.70330	$ 2.73592	$ 2.75120	per 4CP Kva
	DISTRIBUTION SERVICE CHARGE	$ 2.00282	$ 2.52411	$ 2.33441	per Billing Kva
TRANSMISSION	CUSTOMER CHARGE	$ 154 44	$ 222.94	$ 206.41	per Meter per Month
	METERING CHARGE	$ 1,449.82	$ 1,456.82	$ 1,427.55	per Meter per Month
	TRANSMISSION SYSTEM CHARGE	$2.118800	$ 4.72027	$ 4.19062	per 4CP Kva
	DISTRIBUTION SERVICE CHARGE	$0.463296	$ 0 59315	$ 0.59315	per Billing Kva