Control Number: 49421

Item Number: 581

Addendum StartPage: 0

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

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

CROSS-REBUTTAL TESTIMONY AND WORKPAPERS OF

WILLIAM B. ABBOTT

RATE REGULATION DIVISION

PUBLIC UTILITY COMMISSION OF TEXAS

JUNE 19, 2019

581

TABLE OF CONTENTS

WORKPAPERS

I. PROFESSIONAL QUALIFICATIONS

Q. Please state your name and business address.

A. William B. Abbott, 1701 N. Congress Avenue, Austin, Texas 78711.

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

A. I am employed by the Public Utility Commission of Texas ("Commission") as the Director of the Tariff and Rate Analysis Section of the Rate Regulation Division.

Q. What are your principal responsibilities at the Commission?

A. In addition to the supervision and management of the rate analysts and financial analysts in the Tariff and Rate Analysis Section, my principal area of responsibility involves performing analyses of issues such as utility cost allocation, rate design, and tariff filings. My specific responsibilities include: analyzing cost allocation studies, as well as revenue distribution and rate design issues, for regulated electric utilities; analyzing policy issues associated with the regulation of the electric industry; reviewing tariffs of regulated utilities to determine compliance with Commission requirements; preparing and presenting testimony as an expert witness on rate and related issues in docketed proceedings before the Commission and the State Office of Administrative Hearings ("SOAH"); and working on or leading teams in contested cases, rulemaking projects, reports, and research concerning rates, pricing, and other Commission-related issues.

Q. Please state your educational background and professional experience.

A. I earned Bachelor of Science degrees in Chemistry, Psychology, and Economics with a minor in Mathematics from the University of Houston. I earned a Master of Arts degree in Economics from George Mason University while successfully completing all non-dissertation requirements for a Ph.D., with field concentrations in Law & Economics as well as Public Choice Economics. My field concentrations involved the study of the dynamics and social welfare implications of behavior in non-commercial domains such as the legal, political, legislative, and regulatory arenas. For several years as an undergraduate and post-baccalaureate student, I was employed teaching introductory and organic chemistry laboratory courses. As a graduate student, I taught several undergraduate lecture courses including Introductory Microeconomics, Introductory Macroeconomics, Money & Banking, as well as Law & Economics. Subsequent to my graduate studies and prior to my employment at the Commission, I was engaged as a freelance consultant to perform econometric analyses. In 2010, I was hired as a Rate Analyst at the Commission. In 2012, I was promoted to my current position of Director, Tariff and Rate Analysis. I have provided a summary of my educational background and professional regulatory experience in Attachment WBA-1 to my direct testimony in this proceeding.

Q. Have you previously testified before the Commission or SOAH?

A. Yes. A listing of my previously filed written testimony is included in Attachment WBA-1 to my direct testimony in this proceeding.

II. PURPOSE AND SCOPE OF TESTIMONY

Q. What is the purpose of your cross-rebuttal testimony in this case, Commission Docket No. 49421 and SOAH Docket No. 473-19-3864, *Application of CenterPoint Energy Houston Electric, LLC for Authority to Change Rates?*

A. My cross-rebuttal testimony regarding the application of CenterPoint Energy Houston Electric, LLC ("CenterPoint" or "Company") will address certain issues raised in the Direct

Testimony of H-E-B, LP ("HEB") witness George W. Presses,[1] and similar issues raised in the statement of position filed by Texas Competitive Power Advocates ("TCPA"),[2] as well as certain issues raised in the Direct Testimony of Texas Industrial Energy Consumers ("TIEC") witness Jeffry Pollock.[3] The issues raised by these witnesses are relevant to the following items from the Preliminary Order in this proceeding:

> 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?[4]
>
> 46. What are the appropriate allocations of CenterPoint's revenue requirement to functions and rate classes?
>   a. … Do all allocation factors properly reflect the types of costs allocated?
>
> 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?

Q. What items did you review to arrive at your recommendations?

A. In preparing my cross-rebuttal testimony on these issues, I reviewed portions of intervenor testimony and statements of position, CenterPoint's application and direct testimony, certain responses to requests for information, previous proceedings and reports before the Commission, and certain Commission rules.

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[1] Direct Testimony of George W. Presses on Behalf of H-E-B, LP (June 6, 2019).

[2] Texas Competitive Power Advocates Statement of Position (June 12, 2019).

[3] Direct Testimony of Jeffry Pollock on Behalf of Texas Industrial Energy Consumers (June 6, 2019).

[4] Preliminary Order at bates 8 and 10 (May 9, 2019).

Q. What is the basis for your review?

A. Public Utility Regulatory Act[5] ("PURA") § 36.003(a) requires that the Commission "shall ensure that each rate an electric utility or two or more electric utilities jointly make, demand, or receive is just and reasonable." PURA § 36.003(b) states that a rate "may not be unreasonably preferential, prejudicial, or discriminatory but must be sufficient, equitable, and consistent in application to each class of customer." PURA § 36.055 states: "Costs of facilities, revenues, expenses, taxes, and reserves shall be separated or allocated as prescribed by the regulatory authority." PURA § 35.004(d) states:

> The commission shall price wholesale transmission services within ERCOT based on the postage stamp method of pricing under which a transmission-owning utility's rate is based on the... annual costs of transmission divided by the total demand placed on the combined transmission systems of all such transmission-owning utilities within a power region.

PURA § 36.051 states:

> In establishing an electric utility's rates, the regulatory authority shall establish the utility's overall revenues at an amount that will permit the utility a reasonable opportunity to earn a reasonable return on the utility's invested capital used and useful in providing service to the public in excess of the utility's reasonable and necessary operating expenses.

PURA § 36.053(a) states: "Electric utility rates shall be based on the original cost, less depreciation, of property used by and useful to the utility in providing service."

Under 16 TAC § 25.234(a), relating to Rate Design, 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." 16 TAC § 25.192(b)(1) implements PURA § 35.004(d), and requires:

[5] Public Utility Regulatory Act, Tex. Util. Code Ann. §§ 11.001-58.302 (West 2016 & Supp. 2017), §§ 59.001-66.016 (West 2007 & Supp. 2017) (PURA).

> A TSP's transmission rate shall be calculated as its commission-approved transmission cost of service divided by the average of ERCOT coincident peak demand for the months of June, July, August and September (4CP) . . . . 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.

16 TAC § 25.192(c), implementing PURA § 36.051 for wholesale transmission rates, requires that:

> The transmission cost of service for each TSP shall be based on the expenses in Federal Energy Regulatory Commission (FERC) expense accounts 560-573 ... plus the depreciation, federal income tax, and other associated taxes, and the commission-allowed rate of return based on FERC plant accounts 350-359...

III. SUMMARY OF RECOMMENDATIONS

Q. What is your recommendation?

A. TIEC witness Pollock opposes CenterPoint's "zeroing out" the Transmission Cost Recovery Factor ("TCRF") rider by moving wholesale transmission expenses into the base rate Transmission Service Charge, and he additionally claims that extreme "cost-shifting" resulting in rate shock will occur unless the update to the 4CP allocation factor is "moderated." While Mr. Pollock raises some legitimate concerns regarding the current TCRF rule that may warrant Commission consideration of a rulemaking proceeding, I recommend that the Commission reject his proposal to "moderate" the update to the 4CP allocation factor. Rates should be set at cost. Furthermore, CenterPoint's "zeroing out" the TCRF rider is consistent with precedent, and in fact serves to mitigate the "cost-shifting" or "rate shock" that Mr. Pollock claims is a concern under the current TCRF rule.

Accordingly, I recommend that the Commission reject TIEC's proposal to move the entirety of wholesale transmission expense recovery into the TCRF rider.

HEB's testimony and TCPA's position on 4CP allocation issues appear at times to confuse *cost allocation* with *rate design*, as their proposals regarding "cost allocation" appear to be motivated by concerns that arise due to 4CP *rate design*. HEB's and TCPA's recommendations that *transmission* costs be allocated based on a non-coincident peak ("NCP") basis is inconsistent with cost causation and Commission precedent, and should be rejected; however, their recommendation that *distribution* costs be allocated based on NCP is reasonable, as such an allocation is consistent with cost causation and Commission precedent. Furthermore, contrary to HEB and TCPA's contentions, there is no inappropriate cost shifting or energy market "distortion" associated with a coincident peak ("CP") rate design for *transmission charges*, including the 4CP *transmission charge* rate design proposed by CenterPoint; however, there is some merit to their apparent concerns with CenterPoint's 4CP rate design for *distribution charges* applicable to retail Transmission customers, and it would be reasonable for the Commission to address their concern by approving an NCP rate design for these *distribution charges* and an NCP cost allocation for demand-related distribution costs.

IV. SUMMARY OF THE VARIOUS "4CP" ISSUES RAISED BY PARTIES

Q. Are there several distinct "4CP" issues that have been raised by parties to this proceeding?

A. Yes. There are several distinct issues related to 4CP, and some ambiguous phrasing on the part of some parties to this proceeding. The various 4CP issues are:

1. **<u>"CenterPoint 4CP" versus "ERCOT 4CP" Class Allocation</u>** - This issue concerns the particular numerical values of the *4CP class allocation factor* used to allocate certain costs among the retail rate classes. CenterPoint's proposal, as made clear in its errata filing, is to use the *CenterPoint system peaks* to calculate the 4CP class allocation factor (the "CenterPoint 4CP class allocation factor"). As discussed in the direct testimonies of Staff witness Murphy and TIEC witness Pollock,[6] CenterPoint's use of the CenterPoint system peak is an unexplained and unsupported departure from cost causation and well-established precedent, which requires the use of the *ERCOT system peaks* to calculate the 4CP class allocation factor ("ERCOT 4CP class allocation factor"). I will not address this issue in my cross-rebuttal testimony.

2. **<u>Transmission and Distribution Demand Allocation Factors</u>** – This issue concerns how the 4CP class allocation factors are used in establishing rates. CenterPoint has proposed using the (CenterPoint) 4CP class allocation factor for a majority of both the *transmission* and the *distribution* demand-related costs.[7] HEB and TCPA state that they oppose the use of a 4CP class allocation factor (either the CenterPoint 4CP or the ERCOT 4CP) for these costs, and propose instead the use of a non-coincident peak ("NCP") class allocation factor for both *transmission* and *distribution* demand-related costs. Whereas Item 1, above, relates to the numbers

[6] Direct Testimony of Brian T. Murphy, Rate Regulation Division, Public Utility Commission of Texas at bates 44 – 47 (June 12, 2019). Direct Testimony of Jeffry Pollock on Behalf of Texas Industrial Energy Consumers at bates 11 17 (June 6, 2019).

[7] Note that CenterPoint proposes that certain distribution costs be allocated using other, non-demand-related allocation factors, such as weighted number of customers The allocation of these non-demand-related costs does not appear to be implicated by the testimonies I discuss here, and therefore my discussion will be limited to the demand-related costs.

that should be included in the 4CP class allocation factor, this issue is about whether to use a 4CP class allocation factor or the NCP class allocation factor. As discussed below, I recommend rejection of HEB's and TCPA's proposal to allocate *transmission* costs on the basis of NCP. I am not opposed to HEB's and TCPA's proposal to allocate demand-related *distribution* costs on the basis of NCP.

3. **4CP Rate Design versus NCP Rate Design** – In contrast to the *cost allocation* issues above, which involve the amount of costs allocated to particular classes of customers, this *rate design* issue involves how customers within a class are charged based on their load or energy usage. Mr. Pollock testifies in support of CenterPoint's proposal to continue the use of a 4CP *rate design* for both *transmission* and *distribution* rates applicable to retail Transmission customers – this 4CP rate design means that customers are charged based on their individual loads at the times of the system peaks.[8] This contrasts with an NCP rate design, where a customer is billed based on their maximum individual load during a month regardless of when that customer's peak load occurred, and regardless of that customer's load at the time of the system peak. While HEB and TCPA state that their concerns are with 4CP *class allocation* their testimony appears to be more concerned with the effect of the 4CP *rate design* as regards such a rate design providing the direct incentive for customers to reduce load at the system peak intervals. If HEB or TCPA is advocating an NCP rate design instead of a 4CP rate design, I would recommend rejecting such a proposed NCP rate design for *transmission charges* as inconsistent with precedent and cost-causation. However,

[8] Direct Testimony of Jeffry Pollock on Behalf of Texas Industrial Energy Consumers at bates 8 and 24 (June 6, 2019).

an NCP rate design is the standard Commission-approved rate design for *distribution charges* for most non-residential rate classes, and it would be reasonable for the Commission to adopt such a proposal. I discuss these issues below.

4. **Cost-based Rates versus "Moderating" the Update to the 4CP Class Allocation Factor** – TIEC witness Pollock recommends that moving rates to cost would be extreme and would result in rate shock or "cost-shifting," which can be avoided by "moderating" the changes to the 4CP class allocation factors by some unspecified amount.[9] As discussed in the direct testimony of Staff witness Brian Murphy, rate shock is not a concern in this proceeding,[10] and I recommend rejecting Mr. Pollock's proposal on this issue, as discussed below.

V. RESPONSE TO TIEC WITNESS JEFFRY POLLOCK

Class Revenue Distribution and Ratemaking Background

Q. What are the basic phases of retail electric utility ratemaking?

A. The ratemaking process generally proceeds as follows:

1. Total company cost of service and revenue requirement are determined (Cost of Service).
2. Texas jurisdictional cost of service and revenue requirement are determined, if necessary (Jurisdictional Cost of Service).[11]

[9] Direct Testimony of Jeffry Pollock on Behalf of Texas Industrial Energy Consumers at bates 37 - 38 (June 6, 2019).

[10] Direct Testimony of Brian T. Murphy, Rate Regulation Division, Public Utility Commission of Texas at bates 52 - 56 (June 12, 2019).

[11] Not necessary in this proceeding.

3. The cost of service for each class of customers is determined (Class Cost of Service).
4. The revenue requirement for each class is determined (Revenue Distribution).
5. The individual rates within each class are determined (Rate Design).

Q. What does the class revenue distribution phase of the ratemaking process entail?

A. Revenue distribution involves establishing the revenue requirement for each class such that the total Texas jurisdictional revenue requirement is met. The class revenue distribution phase typically occurs after the class cost of service phase and before the rate design phase for the individual classes. The revenue distribution is informed by the results of the Class Cost of Service Study (CCOSS). In the rate design phase, rates are designed for each class to closely match the class revenue requirement established in the revenue distribution phase.

The key question addressed in the revenue distribution phase is whether to set class revenue requirements equal to cost, as shown in the CCOSS and as required under 16 TAC § 25.234, or to employ some form of "gradualism" or rate "moderation" adjustment wherein the revenue requirements for one or more classes are set at a level below cost while other classes (necessarily) have revenue requirements set above cost. If gradualism is appropriate, the details of how costs are to be shifted among customers must be determined.

Q. When is a gradualism adjustment appropriate?

A. While setting class revenue requirements at cost is strongly preferred on efficiency and equity grounds (in addition to being consistent with 16 TAC § 25.234), a gradualism adjustment may be appropriate where movement to cost would result in an increase that is out of proportion or harsh to a particular class,"[12] or where the increases are "harsh to particular classes and promote rate shock."[13]

Q. Is rate shock as much of a concern for transmission and distribution utilities such as CenterPoint as it is for vertically integrated utilities?

A. No. As a transmission and distribution utility ("TDU"), CenterPoint's rates do not include any generation-related costs, and therefore represent a significantly smaller fraction of a typical customer's total electric bill when compared to a vertically integrated generating utility's rates. In other words, the percentage increase in rates that might warrant a rate moderation adjustment is much higher for TDUs than it is for vertically integrated utilities – an 80% increase in a TDU's rates might correspond to a 30% increase in a vertically integrated utility's rates, when looking at the impact on a total bill basis. As the Commission has recently approved moderated base rate increases for certain customer classes of vertically integrated utilities in excess of 42%, or 2.7 times the system-average increase,[14] one must keep in mind that the comparable percentage rate increase for CenterPoint would be much higher. None of the rate increases proposed by CenterPoint would be out of proportion or harsh to a particular class, and therefore rate shock is not a concern in this proceeding.

[12] *Application of Entergy Texas, Inc for Authority to Change Rates, Reconcile Fuel Costs, and Obtain Deferred Accounting Treatment*, Docket No. 39896, Proposal for Decision at 284 (Jul. 6, 2012).

[13] *Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs*, Docket No. 40443, Redacted Proposal for Decision at 269 (May 20, 2013).

[14] *Application of Southwestern Electric Power Company for Authority to Change Rates*, Docket No. 46449, Commission Number Run, Memorandum of William Abbott (Dec. 20, 2017).

Q. Are there distinct regulatory concerns that arise regarding class cost allocation and revenue distribution?

A. Yes. In the class cost allocation and revenue distribution phases the total Texas jurisdictional revenue requirement is fixed. Therefore, compared to setting class revenues equal to cost, any particular gradualism or rate moderation adjustment will benefit some ratepayers at the expense of others. Because of this "zero-sum" situation among ratepayers, there is a significant change in the array of interests and complexity of issues as one transitions from the total company cost of service phase to the later cost allocation and revenue distribution phases. The initial phases are generally bi-lateral with respect to interests (utility versus ratepayers) and one-dimensional in complexity (higher versus lower revenue requirement). The later cost allocation and revenue distribution phases are multi-lateral with respect to interests (all the ratepayer classes versus each other) and multi-dimensional in complexity (many different class revenue requirements that could be higher or lower). Therefore, it is possible that each intervening party could propose or support one or more gradualism adjustments that favors their class(es) by shifting cost recovery to other classes, even where no gradualism adjustment is warranted. In my experience, typical intervenor positions on revenue distribution issues appear to be influenced by the narrow interest of the class(es) they represent.

Q. Are there other, more practical regulatory concerns regarding revenue distribution?

A. Yes. Because intervenors tend to be directly interested in the level of rates that their class(es) are subject to, and only indirectly concerned with the overall level of a utility's rates, there are practical concerns related to asymmetric intervenor representation as well as the possibility of biased collaboration. Because of the zero-sum, class-versus-class nature and unavoidable subjectivity inherent in gradualism or rate moderation adjustments, an important concern arises due to the fact that some classes may have no representation as intervenors in the ratemaking process. Furthermore, even among those classes that do have representation as intervenors, there may be a high degree of asymmetry with respect to the degree to which the intervenor has an incentive to work for the benefit of its class – an intervenor that represents 95% of the load of a class has a much stronger incentive to work for the benefit of its class, compared to a different intervenor that represents 10% of the load of its class.[15] Similarly, intervenors with load in more than one class could have the incentive to favor the class or classes where most of their load resides, even at the expense of a class where a small portion of their load resides.

This issue of asymmetric intervenor representation can be more severe in situations where a company proposes a gradualism adjustment that generally benefits those classes with more active intervenor representation at the expense of those classes that have less, or no, intervenor representation. A gradualism adjustment that shifts cost recovery away from active intervenors and onto customers with less active intervenor representation would likely engender less intervenor opposition for a given level of overall revenue increase. This could result in a scenario in which the utility receives a larger-than-otherwise overall rate increase due to less opposition, active intervenors receive a short-term benefit in the form of a below-cost increase for their classes, and the remaining classes end up with above-cost rates. Even absent utility support for such a gradualism adjustment, the active

[15] This occurs because the benefits that accrue to a class are typically spread among the customers of the class. For example, if the former intervenor can shift $1 million of cost recovery away from their class and onto others, they would benefit by $950,000, whereas the latter intervenor would only benefit by $100,000 by shifting the same $1 million of cost recovery away from their class. The former intervenor would therefore have a stronger incentive to actively shift cost recovery away from their class.

intervenors may propose and support gradualism adjustments that benefit them collectively at the expense of the remaining classes.[16]

Q. Given the above concerns, what do you recommend?

A. Any arguments in support of a gradualist approach to revenue distribution or rate design should be given a high degree of critical scrutiny in order to determine if they meet the required showing that undue rate shock is a serious concern. No party in this case has made such a showing, and rates should be based on cost in this proceeding.

Q. Is it standard practice for the Commission to adopt a rate moderation, or gradualist, approach to setting rates?

A. No. For example, in CenterPoint's last base rate proceeding, the Commission established rates at cost:

> In allocating costs, CenterPoint followed the principles of cost causation. Each of the retail delivery classes has been allocated revenues in line with the costs those classes generate.[17]

This approach is also consistent with prior TDU rate case decisions:

> The increases assigned to each of the generic rate classes are the result of moving each rate class to unity (*i.e.*, an equalized rate of return or full recovery of allocated costs).[18]

Compared to ratemaking in areas not subject to competition, setting rates at cost is more important in the competitive ERCOT market, and has been an important component of Commission policy since the inception of the competitive market. In determining the

[16] It is, however, often the case that some intervenors would benefit from and support cost-based rates in a particular rate case.

[17] *Application of CenterPoint Electric Delivery Company, LLC for Authority to Change Rates*, Docket No. 38339, Order at 33, Finding of Fact No. 175 (June 23, 2011).

[18] *Application of AEP Texas Central Company for Authority to Change Rates*, Docket No. 33309, Order on Rehearing at 18, Finding of Fact No. 142 (March 4, 2008).

standard ratemaking treatments for TDUs in the competitive market, 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.[19]

<u>Rate Shock is Not an Issue in This Proceeding, and Rates Should be Set at Cost</u>

Q. What does Mr. Pollock claim regarding the need to "moderate" the rate increase due to "cost-shifting" associated with the update to the 4CP allocation factor?

A. Mr. Pollock's gradualism proposal departs a bit from the typical process discussed above, in that he proposes that rate moderation be implemented by moderating the change to the 4CP class allocation factor; however, it ultimately amounts to the same proposal to avoid setting rates based on cost as reflected using the appropriate Test Year allocation factors.[20] Mr. Pollock provides a table comparing the 4CP allocation factor values approved in CenterPoint's last rate case with the one proposed by CenterPoint in this proceeding. This Table 8 in his testimony shows that the value of the allocation factor for the retail Transmission class increases from 12.22% (in the "Current" column) to 14.92% between rate cases, and he claims this increase is "extreme and would result in rate shock."[21] While

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[19] Open Meeting Transcript, June 29, 2000, at p. 120 – 121.

[20] Instead of proposing a gradualism/rate moderation adjustment *after* the class cost of service phase, Mr. Pollock proposes that such an adjustment be implemented via an adjustment to an allocation factor used in the class cost of service study. This would result in the study producing class "costs of service" amounts that do not reasonably reflect the actual costs to serve the classes.

[21] Direct Testimony of Jeffry Pollock on Behalf of Texas Industrial Energy Consumers at bates 36 (June 6, 2019).

he does not use the term, Mr. Pollock is essentially arguing for a "gradualism" adjustment, wherein instead of establishing rates base on cost as required under 16 TAC § 25.234(a), the rate increase is "moderated" for certain classes. This "moderation" would result in the rates for the beneficiary class being set below cost, with the other classes bearing the burden of this subsidization by having rates established that are above cost. Mr. Pollock states that adopting moderated 4CP allocation factors "would appropriately temper what *could* otherwise be massive cost-shifts resulting in very large delivery rate increases."[22] He further claims that this gradualist approach is not contrary to establishing cost based rates because the situation arises due to flaws in the current TCRF rule.[23] Contrary to Mr. Pollock's claims, and as discussed below, setting rates at cost would not result in massive cost-shifts or very large overall rate increases.

Q. Which customers would be expected to benefit most from Mr. Pollock's proposal?

A. Typically, the rate class or classes that face the largest revenue requirement increases under full movement to cost are the ones that benefit most from any rate moderation applied. Under CenterPoint's request, the only rate class facing an increase to its 4CP class allocation value is the retail Transmission Service class. Thus, Mr. Pollock's position on gradualism would primarily benefit the industrial customers on whose behalf he is testifying, by reducing the increase they would face if rates were set at cost, as reflected using the "unmoderated" 4CP class allocation factor. CenterPoint's proposed retail transmission function revenue requirement is approximately $943 million, so a one percentage point reduction in the 4CP class allocation factor value for the retail Transmission rate class would reduce the class revenue requirement by about $9 million

[22] *Id.* at bates 37 – 38 (emphasis added).

[23] *Id.* at bates 38.

out of the proposed $162 million, shifting cost recovery of that $9 million onto other customers.

Q. Is the 22.1% increase indicated in Mr. Pollock's Table 8 representative of the actual rate increase faced by the retail Transmission rate class in this proceeding?

A. No. Mr. Pollock obtains that number by comparing the allocation factor from the previous case to the allocation factor proposed by CenterPoint. This is an inapposite comparison for two reasons.

First, the total present revenues paid by current customers are not entirely based on the 4CP allocation factor from CenterPoint's last rate case, so Mr. Pollock's use of the "Current" label in Table 8 is not accurate. As Mr. Pollock himself points out elsewhere in his testimony discussing the flaws in the TCRF formula, load growth between rate cases results in a level of rate revenue that differs from the previously established allocation factor.[24] In other words, due to load growth since the last rate case, the retail Transmission service class is paying more than the 12.22% "Current" share from CenterPoint's last rate case indicated in Mr. Pollock's Table 8, as its load has grown faster than average. Thus the increase faced by the retail Transmission Service class due to updating the 4CP allocation factor is less than the 22.1% that Mr. Pollock suggests in Table 8 of his testimony. This can be seen by the fact that, at CenterPoint's filed request, the retail Transmission Service class is facing only a 13.42% increase in base and TCRF revenue requirement,[25] which falls to 11.8% when considering the Rider UEDIT credit.[26] Mr. Pollock's suggestion that industrial customers would be facing a 22.1% increase in the

[24] *Id.* at bates 8.

[25] Application, Rate Filing Package at Schedule II-I.

[26] Application, Direct Testimony of Matthew A. Troxle at bates 2994.

absence of "moderation" is belied by the fact that CenterPoint's as-filed request for these customers is only an 11.8% increase.

Additionally, and as discussed in the direct testimony of Staff witness Murphy and in Mr. Pollock's own direct testimony, CenterPoint's proposed 4CP allocation factor is a departure from past Commission precedent. If the Commission were to adhere to its precedent, the 4CP allocation factor value for the retail Transmission class would be 13.46%,[27] not the 14.92% increase proposed by CenterPoint and used in Mr. Pollock's comparison. Putting aside for a moment the inaccuracy of the "Current" label in Mr. Pollock's Table 8, and including the 13.46% value consistent with precedent into Table 8 (instead of the Company's proposed 14.92% value) would produce a 4CP class allocation factor change of approximately 10% for retail Transmission customers, instead of Mr. Pollock's claimed 22.1%. A 10% increase in delivery charges does not rise to the level of rate shock that would justify departing from the requirement that rates be based on cost, nor does the Company's proposed 11.8% overall increase for these customers.

Q. Is Mr. Pollock's "moderation" proposal consistent with Commission precedent?

A. No. Mr. Pollock's proposal conflicts with Commission precedent in several ways. It fails to adequately address the requirements of 16 TAC § 25.234, the Commission's preference for cost-based rates, and the standards that must be met before rate moderation is appropriately applied. Furthermore, Mr. Pollock's rate moderation proposal conflicts with recent Commission precedent with regards to how rate impacts are to be evaluated when considering the need for rate moderation or gradualist approaches.

[27] Direct Testimony of Brian T. Murphy, Rate Regulation Division, Public Utility Commission of Texas at bates 47 (June 12, 2019). Direct Testimony of Jeffry Pollock on Behalf of Texas Industrial Energy Consumers at bates 16 (June 6, 2019).

Q. How does Mr. Pollock's proposal fail to address the Commission's standards for applying gradualism?

A. As discussed above, a gradualism adjustment is appropriate where movement to cost would result in an increase that is "out of proportion or harsh to a particular class,"[28] or where an increase is "harsh to particular classes and promote rate shock;"[29] and the standard is more difficult to meet for TDUs such as CenterPoint, as compared to vertically integrated utilities. In Southwestern Public Service Company's ("SPS") most recent fully litigated rate case, gradualism was a contested issue. In that proceeding, SPS, a vertically integrated utility, and various parties opposed a class revenue distribution based on setting rates at cost, and instead proposed gradualism adjustments:

> SPS requested rates based on a recent inter-class cost-of-service study (COS study), but with a two-step modification to result in the maximum base-revenue increase for any class being capped at 200% of the system-average increase and no class experiencing a rate decrease. TIEC and Occidental Permian, Ltd. recommended a 150% average-system-wide-increase cap with no class experiencing an increase smaller than 50% of the system-average increase. AXM advocated for a 175% average-system-increase cap. DOE, OPUC, and Walmart supported a gradualism adjustment, depending on the final SPS revenue requirement and the impacts to each rate class. Staff and Pioneer opposed any gradualism adjustment, asserting no customer class's rates would be modified enough to create rate shock. Thus, Staff and Pioneer argued, there is no justification for veering from the Commission's long-standing guiding principle that costs should be borne by the classes who cause them.[30]

The Commission's order in Docket No. 43695 noted that the Proposal for Decision in that case adopted SPS's proposed gradualism treatment:

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[28] *Application of Entergy Texas, Inc. for Authority to Change Rates, Reconcile Fuel Costs, and Obtain Deferred Accounting Treatment*, Docket No. 39896, Proposal for Decision at 284 (Jul. 6, 2012).

[29] *Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs*, Docket No. 40443, Redacted Proposal for Decision at 269 (May 20, 2013).

[30] *Application of Southwestern Public Service Company for Authority to Change Rates*, Docket No. 43695, Final Order at 9 (Feb. 23, 2016).

> In the PFD, the SOAH ALJs concluded that the Commission should adopt rates consistent with SPS's proposed gradualism adjustment. The SOAH ALJs stated their recommendation struck a balance between competing policies and was consistent with recent Commission decisions in Dockets No. 39896 and 40443.[31]

The Commission, however, citing its preference for cost-based rates, declined to adopt a gradualism adjustment in that case and set the revenue requirement for each class based on cost:

> 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 small 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 24.28%. Thus, moving from classes' costs of service and mandating inter-class cost subsidization is not warranted in this proceeding. Consistent with the Commission's decision to not include any adjustments for gradualism, the Commission deletes proposed findings of fact 335 through 337 and instead adopts new findings of fact 335A through 335C, 336A, and 337A through 337C.[32]

The Commission also explicitly rejected the proposals recommended by other parties as unreasonable:

> 337B. All other gradualism-adjustment proposals, including those of TIEC, Occidental, and AXM, are unreasonable and are not adopted.[33]

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[31] *Id.* at 10.

[32] *Id.*

[33] *Id.* at Finding of Fact No. 337B.

The largest class increase as proposed by CenterPoint in this proceeding is 13.4%, or 11.8% after the UEDIT rider credit is applied. This is far below the 24% that failed to warrant rate moderation in a previous Commission decision. Mr. Pollock has failed to demonstrate that CenterPoint's proposed rate increase is so out of proportion or harsh to a particular class that it promotes rate shock.

Q. How does Mr. Pollock's proposal conflict with recent Commission precedent with regards to how rate impacts are to be evaluated when considering gradualism?

A. As mentioned above, Mr. Pollock's gradualism analysis and proposal focuses solely on the change in a single allocation factor from one rate case to the next, and ignores the fact that load growth has occurred for industrial customers, and that the potential for rate shock must be evaluated on the basis of what customers pay *overall*, not based only on a subset of the rates that customers pay (or upon a single allocation factor). This issue of how to properly evaluate rate impacts was recently litigated, with the following outcome:

> The Commission concludes that any gradualism methodology should evaluate the differences in the actual rates that customers pay. Consistent with this approach, the gradualism methodology the Commission adopts in this proceeding requires that each class's present revenue be evaluated inclusive of revenues from both the transmission-cost recovery factor and the distribution-cost recovery factor.[34]

The Commission also found that "any gradualism methodology should evaluate the differences in the actual rates that customers pay."[35] Such an approach stands to reason, as determining whether an increase is harsh or promotes rate shock must focus on what customers actually pay for their electric service *in total*. A customer is not likely to

[34] *Application of Southwestern Electric Power Company for Authority to Change Rates*, Docket No. 46449, Final Order at 8 (Mar. 19, 2018).

[35] *Id.* at Finding of Fact No. 314A.

experience rate shock if one component of their electric bill doubles while another component decreases by an equal or greater amount, resulting in no overall bill increase.

By focusing solely on the portion of delivery base rates affected by the class 4CP allocator, Mr. Pollock's gradualism analysis and moderation recommendation ignores the actual revenues currently being paid by industrial customers for their electric bills. His approach is at odds with the proper way to evaluate rate impacts for purposes of gradualism. When considered in light of the actual electric bills that customers pay, rate shock is not a concern, even under CenterPoint's proposed rate increase with no adjustments. Furthermore, in the event that the Commission approves a rate increase less than that proposed by CenterPoint, it is clearly unnecessary to depart from the requirement under the rules, and the Commission's clear preference, that rates be set at cost.

Q. Would adoption of Mr. Pollock's recommendation promote rate stability?

A. No, not in the long run. Setting rates at cost is fundamental to facilitating a utility's ability to recover revenues under the fair-return standard. The demand and energy usage of various rate classes within a utility system grows or shrinks at different rates. As customer usage changes, so do the costs that customers impose on the utility system. When all rates are set to reflect cost, the revenues that a utility recovers via these rates more closely matches the costs incurred as customer usage changes. Maintaining subsidized rates for some customers, as Mr. Pollock proposes, means that the revenues recovered via the below-cost rates (i.e., the rates "moderated" for gradualism purposes) will be insufficient to recover the costs to serve that group of customers. Furthermore, setting subsidized rates for some customers requires that the rates for other customers be set above cost. Because customers tend to respond to lower rates with higher usage, and to higher rates with lower usage, the cross-subsidies present under non-cost-based rates have the perverse result of encouraging usage of the utility system by those customers whose rates are below-cost while discouraging usage of the utility system by those customers whose rates are above-cost. This can lead to a growing gap between revenue recovery and costs. Over time, a rate structure based on such non-cost-based rates will likely fail to yield revenues at a level adequate to allow a utility to recover its reasonable costs and earn a fair return. A utility with rates significantly far from cost would be expected to need to file for rate increases relatively frequently due to the failure of non-cost-based rates to yield the required revenues over time. This has the effect of undermining rate stability by necessitating frequent rate changes and higher rate case expenses. Mr. Pollock's recommendation to employ gradualism for his client's benefit is contrary to establishing a sound and stable rate structure.

Q. Is there any merit to Mr. Pollock's concerns regarding how the 4CP class allocation factors are reset in a rate case?

A. While the facts in this case do not warrant adopting Mr. Pollock's proposal to moderate the update to the 4CP class allocation factor, Mr. Pollock raises a legitimate concern regarding the current language of the TCRF rule for ERCOT distribution service providers ("DSP"), 16 TAC § 25.193; namely, that the TCRF billing determinants are updated on a semi-annual basis while the allocation factor values are typically only reset in base rate proceedings. In general, I agree with Mr. Pollock's analysis that this situation can produce a mismatch between the costs allocated to a rate class and the billing determinants used to calculate the rate for that class.[36] This mismatch *could* increase the magnitude of rate

[36] Direct Testimony of Jeffry Pollock on Behalf of Texas Industrial Energy Consumers at bates 16 (June 6, 2019).

changes seen in a rate proceeding, even where it does not rise to the level of rate shock that requires moderation.

Q. How should the Commission address Mr. Pollock's concerns with regard to the TCRF rule?

A. If the Commission wishes to address Mr. Pollock's concerns with regard to the TCRF rule, I would agree with Mr. Pollock that it is reasonable to require CenterPoint to submit compliance applications to update the 4CP class allocation factors used in TCRFs on an annual or biennial basis.[37, 38] With CenterPoint's deployment of advanced metering, the data are now readily available that would allow for a relatively straightforward update to the allocation factors outside of base rate proceedings. It would also be reasonable for the Commission to consider revising the TCRF rule in a rulemaking proceeding to address Mr. Pollock's concerns. Rate moderation, however, should not be applied in this proceeding.

Q. Please summarize your response to TIEC witness Pollock's "moderation" proposal.

A. TIEC has not shown that moving to cost would be unduly harsh and promote rate shock. In SPS's last litigated base rate proceeding, the Commission rejected gradualism arguments and moved class revenues to cost, including an increase to Street Lighting customers of over 24%. Under CenterPoint's proposal in this case, the highest immediate overall class increase would be 11.8%.[39] Considering non-delivery charges, the increase in total electric bills is likely to be less than half this amount, or below 6%, if the Company's application

[37] Under the TCRF rule, 16 TAC § 25.193(c), the TCRF class allocation factor to be used is the one approved by the Commission "in the DSP's last rate case, unless otherwise ordered by the commission."

[38] Direct Testimony of Jeffry Pollock on Behalf of Texas Industrial Energy Consumers at bates 38 - 40 (June 6, 2019). Note, Mr. Pollock recommends annual updates to the allocation factors, while I feel that biennial updates might strike a better balance between rate stability and resource constraints.

[39] Application, Direct Testimony of Matthew A. Troxle at bates 2994.

is granted with no reductions to its request. In the event that CenterPoint's requested increase is not granted in full, then it is likely that the highest class rate increase would be even lower than these amounts. Excessive or unreasonable rate shock is not a concern in this proceeding, and class revenue requirements should be set at cost. If the Commission wishes to address the concerns raised by Mr. Pollock, it would be reasonable to consider a rulemaking proceeding or a requirement that CenterPoint submit annual or biennial updates to its ERCOT 4CP class allocation factors to be used for TCRF proceedings.

<u>"Zeroing Out" the TCRF</u>

Q. What does Mr. Pollock recommend regarding CenterPoint's proposal to "zero out" the TCRF?

A. CenterPoint proposes to reset the TCRF rates to zero, and include all the current wholesale transmission expenses in the proposed base rate Transmission System Charge.[40] Mr. Pollock recommends that the Commission reject the Company's proposal on this issue, and instead that the entirety of CenterPoint's wholesale transmission expense be included in the TCRF rider and rates.[41]

Q. What is the basis for Mr. Pollock's recommendation to reject the Company's proposal to "zero out" the TCRF?

A. Mr. Pollock notes that under the current TCRF rule for ERCOT DSPs, 16 TAC § 25.193, load growth revenues are not accounted for when determining the amount of incremental cost recovery includable in TCRF rates.[42] This therefore produces a situation where, if

[40] Application, Direct Testimony of Matthew A. Troxle at bates 3032

[41] Direct Testimony of Jeffry Pollock on Behalf of Texas Industrial Energy Consumers at bates 8 (June 6, 2019).

[42] *Id.*

load grows above the Test Year level, TCRF rates would be set at a level in excess of CenterPoint's actual unrecovered incremental wholesale transmission expenses that it incurs as a DSP, resulting in an over-recovery of wholesale transmission expenses. Mr. Pollock correctly notes that his recommendation reflects the status-quo treatment for Oncor Electric Delivery Company and Texas-New Mexico Power.[43]

Q. What do you recommend with regard to Mr. Pollock's proposal on this issue?

A. Again, there is merit to Mr. Pollock's arguments; however, I recommend that the Commission reject Mr. Pollock's proposal that transmission cost recovery be removed from base rate transmission service charges and included entirely in the TCRF rates. Mr. Pollock is correct that load growth is not accounted for under the current TCRF rule, and that over-recovery of transmission expenses is therefore a potential outcome. However, CenterPoint's proposal to "zero out" the TCRF and move cost recovery into base rates is consistent with the existing TCRF rule and precedent. Furthermore, it is important to note that "zeroing out" the TCRF in rate cases actually serves to mitigate the "cost-shifting" or "moderation" issue associated with the resetting of the 4CP class allocation factor that Mr. Pollock also takes issue with, and which I discussed above. Moving transmission cost recovery from the TCRF and into base rates, as proposed by CenterPoint, reduces the magnitude of any mismatch that may arise between the fixed 4CP class allocation factors and the updated billing determinants under the TCRF. This is why the actual overall rate increase faced by retail Transmission customers is less than the 22.1% that Mr. Pollock calculated based solely on the change to the 4CP class allocation factor value for the retail Transmission rate class, as discussed previously. In other words, the two "flaws" in the

[43] *Id.*

TCRF rule that Mr. Pollock takes issue with actually somewhat offset each other, in the sense that load growth serves to mitigate the update to the 4CP class allocation factor. Based on this, I recommend that Mr. Pollock's proposal be rejected, and that CenterPoint's proposal to "zero out" the TCRF be approved.

VI. RESPONSE TO HEB WITNESS GEORGE PRESSES AND TO TCPA ON 4CP ISSUES

Q. What position do HEB and TCPA take with regard to the 4CP issues?

A. There is some ambiguity regarding the exact position which these two parties take. HEB's testimony and TCPA's statement of position state an opposition to a 4CP class *allocation*; however, most of their discussion addresses concerns with a 4CP *rate design*. As mentioned previously, class allocation involves the allocation of costs *among the rate classes* and the establishment of each rate class's cost of service – it addresses the question of how *much* should each rate class pay overall. Rate design refers to the design of the individual rates *within a rate class* based on the class's cost of service and the relevant billing determinants – the question here is what the particular rates should be and how exactly should individuals within a class be charged. To ensure completeness, I will address both 4CP cost allocation as well as 4CP rate design. As these parties recommend non-coincident peak ("NCP") approaches instead of 4CP approaches, portions of my discussion will focus on the difference between coincident-peak (CP) allocations and rate designs in general versus NCP allocations and rate designs.

Q. What are some examples of ambiguity on the 4CP issues?

A. The testimony of HEB witness George Presses states "my testimony addresses the proposed application of the Four Coincident Peak ("4CP") for *distribution allocation...*" (allocation), then goes on to state that the "application of the CenterPoint 4CP or the ERCOT 4CP *in any rate class* distorts the price signals of the energy-only market" (rate design).[44] The same ambiguity arises later in Mr. Presses testimony, when he states "H-E-B favors the NCP *cost allocation...*" (cost allocation) and then that "using the NCP protects H-E-B's customers and Partners from future cost shifting to residential customers that results from *4CP customers* continuing to "game the system" to avoid paying 4CP *charges*" (rate design) and that "all customer classes should *pay* NCP..." (rate design).[45]

TCPA likewise states that it agrees with HEB "that *allocation* of costs on a Non-Coincident Peak (NCP) basis would be preferable..." (cost allocation), but then references that "as much as 1,500 MW of load actively pursues reduction during 4CP intervals..." (rate design).[46] TCPA cites to excerpts from a report by William Hogan and Susan Pope[47] ("Hogan-Pope report") and a report by the ERCOT Independent Market Monitor[48] ("IMM report") to support its position. Where they discuss 4CP issues, both the Hogan-Pope report and the IMM report address concerns related to customers' responses to a 4CP *rate design*, though both reports imprecisely refer to their concerns as related to *cost allocation*.[49]

[44] Direct Testimony of George W. Presses on Behalf of H-E-B, LP at 6 (June 6, 2019).

[45] *Id.* at 19 (emphasis added).

[46] Texas Competitive Power Advocates Statement of Position at bates 1 (June 12, 2019) (emphasis added).

[47] Priorities for the Evolution of an Energy-Only Electricity Market Design in ERCOT by William W. Hogan and Susan L. Pope, Project No. 47199 (May 9, 2017).

[48] 2018 State of the Market Report for the ERCOT Electricity Markets, Potomac Economics (June 2019).

[49] Discussion of these issues outside of ratemaking proceedings often include imprecise terminology.

Q. What is the difference between a 4CP rate design and an NCP rate design?

A. A 4CP rate design is a type of coincident peak rate design, and involves customers being charged based upon their load at the time(s) of the system peak(s). Under an NCP rate design, the customer's billing demand is based upon the individual customer's peak load, regardless of when that customer peak load occurs. A customer might have an individual peak load of 1,000 kW, but only have an average load of 800 kW at the time of the four summer monthly system peaks. Under an NCP rate design, such a customer would have a billing demand of 1,000 kW, while under a 4CP rate design the customer would have a billing demand of 800 kW.

A coincident peak rate design provides a price signal to the customer to reduce its load at times when the customer anticipates a system peak might be established. This incentive to reduce load at the time of the system peak, and the resulting load reductions, are what HEB and TCPA appear to be opposed to, and are what is addressed in the Hogan-Pope and the IMM reports.

For TDUs in the ERCOT region, the Commission has adopted a 4CP rate design for customers with interval data recording meters as standard for *retail transmission service*. This variation on coincident peak rate design uses the average of the customer's load at the time of the four summer monthly system peaks. The Commission-approved standard rate design for *retail distribution service* is an NCP rate design.

Q. Why is it important to distinguish between 4CP allocation issues and 4CP rate design issues?

A. The "market impact" and "cost shifting" concerns raised by HEB and TCPA, and included in the Hogan-Pope and IMM reports, are primarily relevant to the potential for customers to reduce their load at the times of the system peaks, and are therefore *rate design* concerns. While there is a link between cost allocation methodologies and customer incentives to reduce load, this link is weaker and more indirect than the incentives faced due to the rate design. If a customer reduces its coincident peak load during a Test Year then that will reduce the amount of costs allocated to the customer's class under a coincident peak allocation factor in the subsequent rate proceeding, but that is a smaller and less direct reduction than the reduction in the customer's bill if the customer reduces its coincident peak load under a coincident peak rate design, as doing the latter directly reduces the customer's billing units and delivery charges. In other words, if HEB's and TCPA's recommendations to change the 4CP *cost allocation factors* to NCP *cost allocation factors* is adopted, but certain customers still face 4CP *rate designs*, then those customers will still face the incentive to reduce load at the times of the system peaks, giving rise to the "market impact" and "cost shifting" issues complained of by HEB and TCPA. Furthermore, there are requirements under PURA for a coincident peak rate design with regards to wholesale transmission rates.

Q. What is your recommendation in response to HEB's and TCPA's proposals to reject 4CP allocation factors and 4CP rate designs in favor of NCP allocation factors and NCP rate designs?

A. HEB's and TCPA's proposals for NCP cost allocations and rate designs should be rejected insofar as they apply to *transmission* costs and charges. A coincident peak allocation and rate design is appropriate for these transmission costs. Regarding demand-related *distribution* costs, HEB's and TCPA's proposals for NCP cost allocations and rate designs are reasonable, and are consistent with standard Commission practice. While Staff did not recommend rejecting CenterPoint's proposed 4CP allocation and rate design for demand-related distribution costs, Staff is not opposed to HEB's and TCPA's proposed NCP allocation and rate design for *demand-related distribution* costs.

A 4CP Rate Design for Transmission Rates is Appropriate

Q. Why is a coincident peak rate design appropriate for transmission costs?

A. The transmission system must be sized to meet the maximum load imposed upon it. It is therefore customers' load coincident with the system peak that is the primary driver of transmission system costs. Coincident peak allocations and rate designs therefore best reflect cost causation when it comes to the transmission system costs. PURA § 35.004(d) recognizes this, and requires a coincident peak rate design for wholesale transmission cost recovery in the ERCOT region:

> The commission shall price wholesale transmission services within ERCOT based on the postage stamp method of pricing under which a transmission-owning utility's rate is based on the ... costs of transmission divided by the total demand placed on the combined transmission systems of all such transmission-owning utilities within a power region.

In implementing this section of PURA, the Commission's rule regarding transmission rates, 16 TAC § 25.192(b)(1), mandates a 4CP transmission rate design:

> A TSP's transmission rate shall be calculated as its commission-approved transmission cost of service divided by the average of ERCOT coincident peak demand for the months of June, July, August, and September (4CP)... 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.

Q. Is there inappropriate "cost-shifting" caused by 4CP retail transmission rate design?

A. No. HEB and TCPA appear to suggest that the 4CP rate design for retail transmission, by encouraging load reductions around the system peaks, leads to inappropriate cost-shifting.

Mr. Presses states "the customers that can avoid the cost, will avoid the cost, shifting the remaining class costs to other customers in that class."[50] TCPA, citing the Hogan-Pope Report, states that demand reductions during peak periods "provides no costs savings to the market on a net basis, but rather reallocates costs to other customers."[51] These statements are incorrect.

As mentioned previously, at the system level, higher peak demands on the transmission system are the primary drivers of the size, and therefore cost, of the transmission system. Load reductions at the times of the system peaks, as encouraged by coincident peak rate designs, therefore reduce the incurrence of transmission costs for the whole system below what they otherwise would be. As TCPA notes, the IMM Report estimates that as much as 1,500 MW of load pursues reductions during CP intervals.[52] Without these load reductions, more transmission system costs would be incurred overall.

Below the system level, at the level of CenterPoint as a DSP, HEB's and TCPA's cost-shifting arguments are without merit insofar as *transmission* costs are concerned, as their arguments fail to reflect how transmission rates are charged within ERCOT. PURA § 35.004(d) and 16 TAC § 25.192(b)(1) require that CenterPoint be charged wholesale transmission charges based on the Company's 4CP demand. Therefore, if a customer with a 4CP rate design reduces its 4CP load, the customer's load reduction directly results in CenterPoint being charged less for wholesale transmission service – costs are *avoided* for CenterPoint. These wholesale transmission charges to CenterPoint are passed on to customers via base rates and TCRF rates. Since the TCRF allocation factors are typically

[50] Direct Testimony of George W. Presses on Behalf of H-E-B, LP at 6 (June 6, 2019).

[51] Texas Competitive Power Advocates Statement of Position at bates 2 (June 12, 2019).

[52] *Id* at bates 1.

fixed between rate cases, any reduction in CenterPoint's 4CP load caused by incremental 4CP customer load reductions accrues to the benefit of all of CenterPoint's customers – because absent the 4CP customer's load reductions, more transmission costs would be allocated to each rate class under the TCRF.

Thus, when it comes to a 4CP rate design for *retail transmission* rates, cost-shifting is not a legitimate concern, as peak load reductions induced by the 4CP rate design are associated with lower transmission costs at both the ERCOT system level, the CenterPoint system level, and at the retail customer level. This alignment of incentives with cost causation is presumably the reason the Commission approved the 4CP transmission rate design for customers with interval data recording meters as the standard retail transmission rate design for ERCOT TDUs.

Q. What is the Commission precedent regarding the proper TDU rate design for Transmission System Charges and Distribution System Charges?

A. During the initial unbundling of utilities accompanying the transition to a competitive market, the Commission determined that "a uniform rate design and customer classification scheme is appropriate for the purpose of standardizing transmission and distribution rates in Texas."[53] In establishing the uniform rate design, the Commission stated that "the primary principles to be considered in the design of transmission and distribution rates are cost causation, simplicity, and equity to customers within the given rate classes."[54] The Commission also found that "uniform transmission and distribution rates help to ensure a

[53] *Generic Issues Associated with Applications for Approval of Unbundled Cost of Service Rate Pursuant to PURA § 39.201 and Public Utility Commission Substantive Rule § 25 344,* Docket No. 22344, Order No. 40: Interim Order Establishing Generic Customer Classification and Rate Design at 1 (Nov. 22, 2000).

[54] *Id.* at 5.

more vibrant competitive electric market because the uniformity will facilitate entry by new competitors. The Commission finds that such a generic rate design is appropriate, and therefore, shall be adopted by transmission and distribution utilities."[55]

Regarding retail delivery charges, the Commission considered the concerns raised here by HEB and TCPA regarding "gaming" of the 4CP transmission rate design, stating:

> Many of the parties propose that demand-metered classes should be billed based on the non-coincident peak (NCP) demand. There was greater disparity among the parties as to the issue of whether IDR demand-metered locations should be given different billing treatment from non-IDR locations. Parties opposing the use of a 4CP-billing determinant cited cost shifting and intraclass subsidies as the primary concerns.
>
> With respect to a facilities/delivery charge, the Commission finds that the NCP billing determinant should be used for non-IDR metered customers. For those possessing IDR meter capabilities, the transmission per-kilowatt (kW) rate shall be billed according to the Commission's relevant transmission rule, which currently mandates a four coincident peak (4CP) method. In the event that "gaming" of the 4CP methodology becomes a problem, the advisability of broadening the relevant peak period may be examined at that time. The distribution facilities/delivery charge for IDR metered customers shall be billed on the NCP billing determinant.[56]

The Commission has clearly considered the issues raised by HEB and TCPA, and determined that 4CP rate design is appropriate for transmission rates. The Commission has also determined that departing from the standard rate design, as HEB and TCPA recommend, would harm the competitive market.

[55] *Id.*

[56] *Id* at 6 - 7.

<u>A 4CP Allocation is Appropriate for Transmission Costs</u>

Q. Is CenterPoint's proposed 4CP allocation for transmission costs reasonable and appropriate?

A. Yes. The use of the ERCOT 4CP class allocator is reasonable and appropriate for transmission cost allocation because it is consistent with cost causation as regards how CenterPoint incurs wholesale transmission expense. Precedent and policy support for this approach was included in the direct testimony of Staff witness Brian Murphy.[57] While Mr. Murphy's direct testimony is in opposition to the Company's proposal to use the *CenterPoint system* 4CP in lieu of the *ERCOT system* 4CP, the arguments provided by Mr. Murphy also apply to rejecting HEB's and TCPA's position that transmission costs should be allocated by NCP instead of 4CP.

<u>The Hogan-Pope and IMM Reports are Flawed with Regard to Transmission Rate Design</u>

Q. What are the purposes of the Hogan-Pope report and the IMM report?

A. These reports are primarily concerned with various wholesale electricity market issues, and the vast majority of their content is unrelated to regulated utility rate design or the other issues in this proceeding. The reports do include short discussions of 4CP rate design issues, as referenced by TCPA in its statement of position in support of HEB's testimony.

Q. Has the Commission discussed the transmission cost allocation suggestions included in the Hogan Pope report?

A. Yes. Shortly after the report was issued, the conflict between the report's transmission ratemaking recommendations and PURA was discussed at the Commission:

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          COMM. ANDERSON:  -- which takes us to Item
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[57] Direct Testimony of Brian T. Murphy, Rate Regulation Division, Public Utility Commission of Texas at bates 43 – 47 (June 12, 2019).

> No. 18 that I would like to bring up an issue.
>
> On May 10th of this year there was filed in a number of dockets by Calpine and NRG a report entitled "Priorities for the Evolution of the Energy-Only Electricity Design in ERCOT that was prepared by Dr. William Hogan and Dr. Susan Pope of FTI Consulting.
>
> ...
>
> There's the issue of co-optimization and in particular local scarcity pricing, and then there's some suggestions -- or analysis and suggestions around transmission planning and cost allocation of those.
>
> ...
>
> With respect to cost allocation, I don't plan on taking that up, for one, if for no other reason than that it would require, I think, a change to law.
>
> So we'd be, I think, wasting our time,[58]

Q. Do the Hogan-Pope Report and the IMM Report cited by TCPA provide a reasonable basis for rejecting CenterPoint's proposed 4CP allocation and rate design for transmission costs?

A. No. The reports are both fundamentally flawed in their critiques of transmission rate design as they are focused on the ERCOT energy market in isolation, and do not reflect a consideration of the broader public and ratepayer interest perspective. Both of the reports also reflect a lack of understanding with respect to certain ratemaking principles. The

[58] Open Meeting Transcript, May 18, 2017, at p. 34 - 36.

terminology used in the reports also adds to the confusion previously discussed, as they both conflate *cost allocation* with *rate design.*

Q. How do the reports fail to consider the broader public and ratepayer interest perspective?

A. Where they address transmission rates, both of the reports are limited in scope to considering only the effects of 4CP transmission rate design on the ERCOT energy market, and they do not consider the overall effects on customers of the rate design and the market combined. For example, the Hogan-Pope Report states "this price for incremental consumption for 4CP customers during potential peak demand intervals is orders of magnitude higher than the energy price paid to suppliers, creating an inconsistency *from the perspective of the efficient energy-only market design.*"[59] The reports fail to consider that ratepayers are affected by more than just energy market prices – ratepayers are subject to transmission and distribution charges in addition to energy market prices. By focusing solely on what is optimal for the energy market, the reports neglect to consider what is optimal for ratepayers subject to both the market prices and to the regulated TDU rates in combination. That the 4CP rate design for transmission charges has an effect on the energy market that does not reflect the dynamics of the energy market is not a reasonable critique of the transmission rate design; rather, such effects are normal aspects of well-functioning markets, and do not in themselves indicate an inappropriate "distortion."

[59] Priorities for the Evolution of an Energy-Only Electricity Market Design in ERCOT by William W. Hogan and Susan L. Pope, Project No. 47199 at 77 78 (May 9, 2017) (emphasis added).

Q. How is it that the alleged "distortions" caused by the 4CP transmission rate design are normal aspects of well-functioning markets?

A. TCPA cites to claims in the Hogan-Pope report that the energy market price reductions caused by customers reducing 4CP load is "distortive," and also references the IMM report, which states that "by curtailing load in response to incentives that are not aligned with the real-time energy market, supply is uneconomically reduced and the real-time market is adversely affected."[60] These arguments are incorrect from the broader ratepayer perspective. Transmission service and energy supply are what economists refer to as *complements*, or *complementary goods* – two goods that are primarily consumed together. As complements, transmission service and energy supply experience joint demand, and exhibit negative cross elasticity of demand. In layman's terms, this means that if the price of one complement increases, then the demand for the other complement, and its price, tends to fall in response. This is a normal, well-functioning market response.

For example, peanut butter and jelly are two goods that can exhibit complementarity. If a widespread peanut crop failure led to high prices for peanut butter due to scarcity, then the normal market response is that the price of jelly would fall as consumers respond to higher peanut butter prices by reducing consumption of both peanut butter and their demand for jelly, putting downward pressure on the price of jelly.

As the reports both correctly note, transmission rates have experience significant increases in the past several years - and it is a normal and healthy economic response for ratepayers to reduce peak load on the transmission system in response to the higher

[60] 2018 State of the Market Report for the ERCOT Electricity Markets, Potomac Economics at xxx (June 2019).

transmission costs, and for the complementary energy market to face some downwards price pressure due to this rational and economically appropriate response.

Q. Is there merit to the Hogan-Pope "sunk cost" critique of 4CP transmission rate design cited by TCPA?

A. No. The Hogan-Pope analysis of transmission rate design, as cited by TCPA, is fundamentally based on the allegation that transmission costs are "sunk costs," and therefore should not be priced in a manner that provides ratepayers an incentive to reduce their load on the transmission system. In addition to conflicting with the PURA § 36.053(a) requirement that rates be based on historical, or "sunk" costs, this argument is flawed as it fails to appreciate well-established principles of ratemaking. Economists generally agree that in a competitive market, prices (or rates) tend not to reflect sunk costs, which are costs that have already been incurred and can no longer be avoided. However, one of the bases of regulated ratemaking for monopoly utilities is that pure marginal cost pricing (which excludes sunk costs) may fail to result in an adequate level of utility service due to the disproportionately high fixed costs and economies of scale associated with utility service.

Furthermore, while historical sunk costs are one input into regulated rates, Hogan-Pope and the IMM fail to appreciate that a significant portion of transmission cost of service involves ongoing costs that are not sunk costs, such as operations and maintenance costs required to serve loads. The reports also neglect the fact that rates are generally established so as to be somewhat representative of ongoing costs and that they serve functions beyond simply recovering costs for the utility.

Q. What criteria of a sound rate structure are not considered in the Hogan-Pope and IMM reports?

A. Both the Hogan-Pope report and the IMM report neglect to consider the aspects of sound ratemaking beyond cost recovery for the utility. As described in the text foundational to rate regulation, James C. Bonbright's Principles of Public Utility Rates, these criteria are:

1. Capital Attraction;
2. Consumer Rationing; and
3. Fairness to Ratepayers.[61]

While Bonbright elsewhere provides more detailed attributes of a sound rate structure, the above-listed objectives are considered primary "not only because of their widespread acceptance, but also because most of the more detailed objectives discussed in the literature are ancillary thereto."[62]

The Capital Attraction criterion involves establishing rates sufficient to attract capital investments to the utility. This is the only one of the three criteria that involves ensuring full cost recovery for the utility. If the other criteria are ignored, and ratemaking was based solely on ensuring that utilities received cost recovery, then the Hogan-Pope and IMM report's suggestions regarding transmission rate design might be reasonable and appropriate. However such a narrow focus on cost recovery alone would represent poor ratemaking as it would fail to appropriately consider the incentive to avoid incurring uneconomical levels of additional transmission costs, and it would also fail to consider matters of ratepayer equity.

[61] James C. Bonbright, Albert L. Danielsen, and David R. Kamerschen, *Principles of Public Utility Rates*, 2d ed. (Arlington, VA: Public Utility Reports, 1988) at 385.

[62] *Id.*

Put simply, the Consumer Rationing criterion involves discouraging wasteful consumption of utility services, while promoting economically justified consumption of utility services. Because both the past and future costs of the transmission grid are largely driven by the peak demands to which the grid must be sized, an efficient transmission rate design should impose costs on ratepayers in a manner that provides an incentive to reasonably mitigate those costs by reducing their coincident peak demand where economically appropriate. The 4CP transmission rate design performs such a function. An NCP rate design for transmission service would be inferior to a CP rate design, because a customer's off-peak load does not significantly contribute to the incurrence of additional transmission costs, while the customer's coincident peak load does so contribute. An NCP rate design may also encourage a customer to reduce their NCP demand even when doing so provides no reduction in transmission system costs. This mismatch between the incentive offered by the rate design and the incurrence of costs makes the NCP rate design inferior to the 4CP rate design with regards to transmission service from a consumer rationing perspective.

The Fairness to Ratepayers criterion addresses whether rates apportion costs in an equitable manner. Here again, cost causation is the primary issue. It is fundamentally equitable to charge customers based on cost causation, and transmission system costs are primarily caused by coincident peak load. Abandoning 4CP transmission rate design in favor of NCP rate design would be a step backwards in terms of ratepayer equity.

Q. Please summarize your position regarding the Hogan-Pope report and the IMM report as cited by TCPA.

A. The small portions of these reports that address transmission ratemaking fail to consider overall ratepayer welfare, and they also fail to consider fundamentally important aspects of ratemaking beyond mere cost recovery. The Hogan-Pope report and the IMM report cited by TCPA should not be heeded when it comes to evaluating the merits of CenterPoint's proposed 4CP transmission cost allocation and transmission rate design for IDR-metered customers.

Q. Are there important and legitimate concerns raised by the Hogan-Pope report and the IMM report regarding transmission rates?

A. Yes. Both of the reports are correct to note concern with the significant increase in transmission rates over the years. Instead of focusing on the 4CP rate design, however, it might be more fruitful for stakeholders concerned about transmission rates to instead consider an examination as to the costs that are being included in the transmission cost of service calculations for the TSPs, both in individual rate proceedings as well as under the transmission rule. For example, Staff witness Murphy includes an extensive discussion of CenterPoint's proposed functionalization of costs to transmission cost of service on pages 17 through 39 of his direct testimony in this proceeding.

Hypothetically speaking, even if it were established that the current 4CP rate design provides too much of an incentive to reduce load around the system peaks, adopting an NCP rate design would not be an appropriate way to address this concern. Maintaining a coincident peak rate design but modifying it from the status quo would be more appropriate. For example, as previously noted, the Commission has suggested the solution of broadening the peak period in the event that "gaming" the 4CP rate design is determined to be a problem.[63] In other words, broadening the 4CP peak period from four 15-minute intervals to four 30-minute intervals for 4CP customers would dilute the incentive to reduce load by requiring a greater degree of load shed for the same overall benefit. This approach would also be consistent with PURA and cost causation, and would represent a less drastic departure from the status-quo, while still addressing the concerns raised in the reports.

VII. CONCLUSION

Q. Please summarize your cross-rebuttal recommendations.

A. My recommendations on cross-rebuttal are as follows:

1. TIEC witness Pollock's proposal to "moderate" the update to the 4CP class allocation factor should be rejected, and rates should be set at cost using the ERCOT 4CP class allocation factor.
2. TIEC witness Pollock's proposal in opposition to CenterPoint's "zeroing out" of the TCRF rider and rates should be rejected, as including transmission cost recovery in base rates mitigates the rate shock concerns that Mr. Pollock expresses with regard to updating the 4CP allocation factor. CenterPoint's proposal is consistent with the TCRF rule and past precedent.
3. HEB's and TCPA's positions that *transmission* costs should be allocated based on NCP should be rejected. CenterPoint's proposal to use a 4CP allocator is

[63] *Generic Issues Associated with Applications for Approval of Unbundled Cost of Service Rate Pursuant to PURA § 39.201 and Public Utility Commission Substantive Rule § 25.344*, Docket No. 22344, Order No. 40: Interim Order Establishing Generic Customer Classification and Rate Design at 6 - 7 (Nov. 22, 2000).

appropriate and consistent with cost causation and precedent, provided the ERCOT 4CP allocator is applied instead of the CenterPoint 4CP allocator.

4. HEB's and TCPA's positions that *transmission* rates should be designed based on an NCP rate design for IDR-metered customers should be rejected. CenterPoint's proposed 4CP rate design for transmission rates is reasonable, appropriate, and consistent with cost causation, PURA, and Commission precedent.

Q. Does this complete your cross-rebuttal testimony?

A. Yes.

WORKPAPERS

FTI CONSULTING

Priorities for the Evolution of an Energy-Only Electricity Market Design in ERCOT

MAY 2017

William W. Hogan, *Harvard University*

Susan L. Pope, *FTI Consulting*

May 9, 2017

Locational Scarcity Pricing

- **Out-of-Market Actions to Manage Transmission Constraints**: Local scarcity pricing and mitigation rules require changes to properly set prices when there are reliability unit commitments or other ERCOT reliability actions to manage transmission constraints; these changes should not disable rules for local market power mitigation.
- **Dispatch and Pricing for Local Reserve Scarcity:** Introduction of local reserve requirements, implemented through co-optimization of the energy dispatch and reserve schedules, would provide a market solution to properly set prices when there are constraints on reserve availability in a sub-region.

Transmission Planning and Cost Recovery

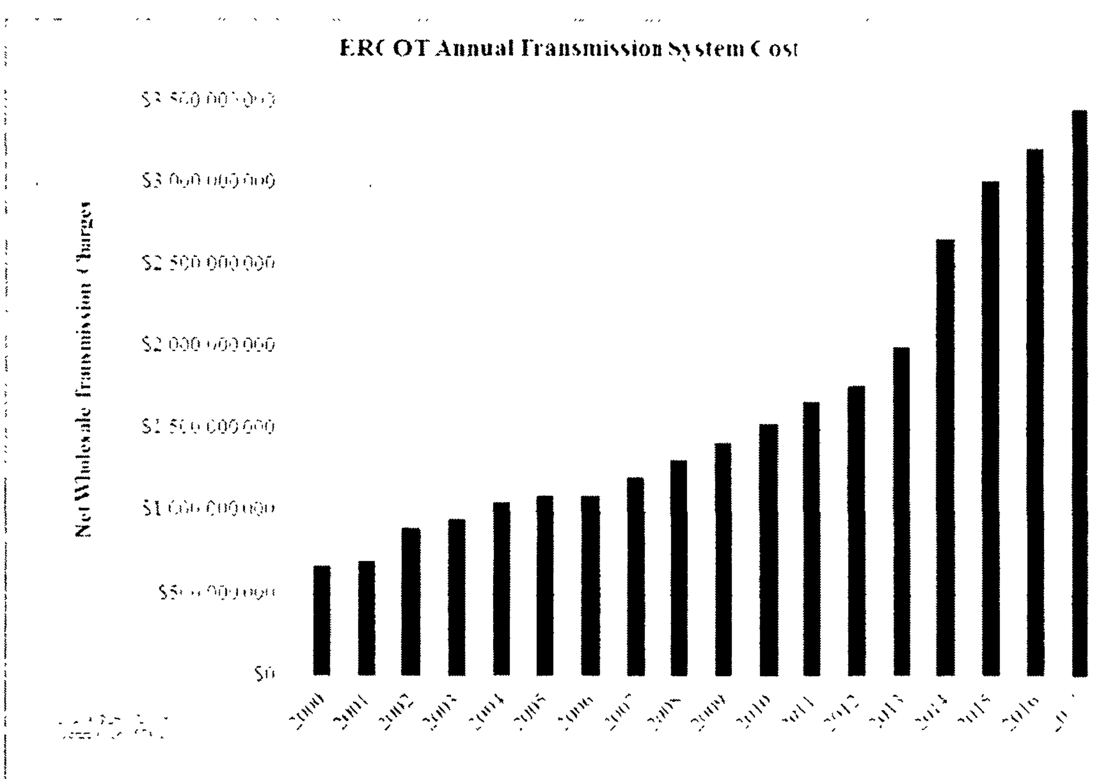
- **Transmission Planning:** Market-reflective policies for transmission investment should be considered as a replacement for Texas' socialized transmission planning, which, by building new transmission in advance of scarcity developing, fails to provide the opportunity for markets to respond.
- **Transmission Cost Recovery:** Alternatives for transmission cost recovery to replace or reduce dependence on the summer peak demand-based mechanism for the allocation of sunk transmission costs would reduce distortion of energy market pricing.

An Appendix provides further details on a formulation and computational approach for calculation of co-optimized prices for energy and operating reserves with local reserve requirements.

FOUR COINCIDENT PEAK (4CP) COST ALLOCATION DISTORTS PEAK PERIOD LOAD

Transmission system investment in Texas exceeded ten billion dollars over the past five years with Texas' CREZ transmission system investment alone exceeding $7 billion.[98] The combination of CREZ and non-CREZ transmission infrastructure development is driving a pronounced increase in ERCOT's annual transmission cost-of-service, as shown in Figure 21.[99]

Figure 21



These substantial increases in the transmission cost-of-service are ultimately passed through to consumers. For example, increases to the transmission components of Oncor's retail delivery

[98] ERCOT, "2016 ERCOT Report on Existing and Potential Electric Constraints and Needs" December 30, 2016, p. 4

[99] In ERCOT Transmission Service Providers (TSPs) charge Distribution Service Providers (DSPs) for transmission service based on each DSP's percentage of 4CP for the prior year. DSPs include investor owned utilities, municipal utilities and cooperative utilities. DSPs pass through transmission system costs pursuant to their retail tariff. In competitive service areas the transmission and distribution system costs are charged to Retail Electric Providers who may bill retail customers.

tariff for distribution system customers have ranged from 72% to 147%, depending on customer class, for the period March 2012 to March 2017.[100]

Transmission costs are sunk because, unlike variable costs, they do not change depending on energy demand in an interval. A general principle of market design is to allocate sunk costs to minimize impacts on real-time markets, since allocating sunk costs based on real-time supply or demand can impact the efficiency of the real-time market. ERCOT does not conform to this principle; rather, the transmission costs charged to the largest customers are determined based on their demand in four peak summer intervals using the Four Coincident Peak (4CP) transmission cost allocation methodology.[101] At the end of each year, the PUCT determines the proportion of ERCOT system-wide 4CP load attributable to each distribution service provider.[102] A distribution service provider's load during the interval in which the system-wide peak occurs for each of the months from June to September defines its share of the 4CP and its corresponding allocation of the yearly ERCOT transmission cost-of-service. Distribution service providers recover their annual allocation of transmission service costs through the delivery service tariffs charged to their different classes of customers. Typically, residential and small commercial customers' delivery service tariffs have an energy based (per-kWh) charge, while large commercial and industrial customer delivery service tariffs have a demand-based (per-kW) charge. The demand charge to large commercial and industrial customers with interval meters is applied to the customer's kW load during the identified 4CP intervals.[103] ERCOT reports that the customers who are billed based on their demand during the 4CP intervals represent 44% of the electric load served by ERCOT.[104]

Inevitably, the 4CP transmission cost allocation rule operates as an outside-the-market effect that suppresses peak and near-peak energy scarcity prices. The pronounced increase in the transmission cost-of-service shown in Figure 21, combined with the structure of the 4CP charge, creates a powerful incentive for customers to take actions to reduce their portion of the

[100] Oncor Electric Delivery Company LLC, "Tariff for Retail Delivery Service," 6 1 1 Delivery System Charges, Applicable: Entire Certified Service Area, Effective Date: March 1, 2017, Sheet 6.1, Page 3 of 4, Revision: Thirty-Two. Note that for transmission system customers (not taking service at distribution voltage levels) the rate has increased 58% over the same time period.

[101] There is an inconsistency between determining planning for new transmission needs based on non-coincident peak loads (Steady State Working Group base case) and allocating the costs of these upgrades based on coincident peak load.

[102] See, for example, Texas Public Utility Commission of Texas, Docket No. 45382, Commission Staff's Application to Set 2016 Wholesale Transmission Service Charges for the Electric Reliability Council of Texas, Electric Reliability Council of Texas, Inc.'s Report on the 2015 "4CP" Coincident Peak Load in the ERCOT Region, December 1, 2015

[103] For example Oncor customer's greater than 10kW are charged the 4CP rate provided that they have an Interval Demand Recorder (IDR) which records customer demand every fifteen minutes. http://www.ercot.com/content/wcm/key_documents_lists/41536/Joint_TDSP_s_4CP_Tariff_Language.docx.

[104] ERCOT, "4CP Overview", February 16, 2017, p. 1; percentage is based on ERCOT load on August. 3, 2011.

transmission cost-of-service. Customers on a 4CP tariff have their monthly transmission charge for the current year calculated based on their prior year's observed 4CP demand. Thus, a customer served under a 4CP tariff that can reduce its load during the actual ERCOT summer monthly system peaks will realize substantial savings on its transmission charges in the following year.

For example, assume an industrial customer has a peak demand of 10 MW and is capable of interrupting its entire demand during each ERCOT peak demand interval during the months of June, July, August, and September.[105] Next, assume that this customer is in the Oncor service territory and served with primary transmission service such that it faces a transmission charge of $4.13 per 4CP kW-month. If the customer were to reduce its 4CP demand to zero, the customer would pay no transmission charge the following year. However, if the customer did not reduce its demand it would be charged 10,000 kW (10 MW) * $4.13/4CP kW, or $41,300/month, which totals $495,600 for the year.

It makes sense for large customers and municipal and cooperative utilities subject to 4CP transmission charges to acquire analytical tools to forecast peak demand periods. Recent ERCOT analyses confirm that as the transmission cost-of-service has increased, customers have been demonstrating increased peak demand reduction coincident with ERCOT's peak periods. For example, ERCOT has recently estimated a pronounced increase in the magnitude of municipal and cooperative utilities' peak demand reduction over the past several years during which transmission costs have increased.[106] Increased transmission costs, combined with the design of the 4CP charge, are reducing peak demand and putting downward pressure on ERCOT energy market prices during peak demand periods.

The 4CP transmission charge raises an issue for energy-only markets because the reduction in demand during peak periods is not occurring in response to energy prices, but instead is in response to avoiding an allocation of sunk transmission costs. The incremental cost faced by 4CP customers for additional power consumption during potential peak intervals is not equal to the energy price paid to energy suppliers at the same location at the same time. During a potential 4CP interval, a 4CP customer faces an incremental cost for an additional MW of consumption equal to (approximately) ¼ of the 4CP transmission charge (since the customer's peak demand is averaged over four intervals), plus the locational price of energy.[107] This price for incremental consumption for 4CP customers during potential peak demand intervals is

[105] This example is based on the now out-of-date example provided by ERCOT in its 4CP Overview, February 16, 2017, p. 4

[106] Raish, Carl L, Principal Load Profiling and Modeling, ERCOT Demand Side Working Group, "Analysis of NOIE Load Reductions Associated with 4-CP Transmission Charges/Price Response in ERCOT," June 17, 2016, at 12. http://www.ercot.com/content/wcm/key_documents_lists/27290/Demand_Response_Presentations.zip

[107] There also is a feedback effect whereby a reduction in the 4CP load of all customers will increase the 4CP rate.

orders of magnitude higher than the energy price paid to suppliers, creating an inconsistency from the perspective of efficient energy-only market design. The 4CP mechanism leads to inefficient load reductions because the marginal cost of electricity supply will be lower than the opportunity cost of load reductions.

With the 4CP transmission cost allocation, 44% of ERCOT load has an enormous out-of-market incentive to reduce demand during exactly the peak intervals when prices would otherwise be high or rising in an energy-only market. In effect, there is a payment, in terms of avoided transmission and distribution charge allocations in the following year, leading to a reduction in peak demand and in energy prices. Importantly, there is no real reduction in transmission or distribution costs. This is clearly demonstrated in Figure 21. The charges are just allocations of sunk costs. Hence, real costs are incurred to reallocate sunk costs among market participants.

ERCOT has recently estimated the 4CP response during peak load hours of as high as 1,408 MW.[108] Assuming this reduction were to occur at a time when the ORDC would otherwise be included in the locational price; prices throughout ERCOT could be reduced by hundreds of dollars per MWh.

Demand reductions resulting from the 4CP transmission cost-recovery mechanism are not in response to high system marginal costs, but instead are in response to the allocation of sunk costs. On a net basis, there are no cost savings, only a reallocation of the costs to other customers. In principle, the most perverse outcome would be to have everyone shifting costs onto everyone else, so that on balance no customer avoids the transmission payment but every customer incurs real expenses in the attempt.

IMPROVEMENTS TO TRANSMISSION PLANNING AND COST RECOVERY TO SUPPORT ENERGY-ONLY MARKET

An alternative approach to the PUCT and ERCOT's current transmission planning and cost allocation rules would be to modify the transmission planning, expansion and cost allocation protocols to focus on a beneficiaries-pay system. Such a system would enable and encourage explicit consideration of all competing investments, including generation and storage, that are substitutes for transmission in meeting system-wide or local reliability objectives during future time periods. As mentioned, the NYISO pro forma process could serve as a model for ERCOT.

The PUCT should be wary of the impact 4CP has on energy price formation. The Commission could evaluate and ultimately adopt an alternate transmission cost allocation methodology that is congruent with the energy-only market. For example, efficient pricing for transmission cost

[108] Raish Analysis at 10.
http://www.ercot.com/content/wcm/key_documents_lists/27290/Demand_Response_Presentations.zip

Locational Scarcity Pricing

- **Out-of-Market Actions to Manage Transmission Constraints:** Reliability constraints can create perverse conditions when they induce out-of-market actions that, in combination with market power mitigation, result in lower, not higher, market prices. Local scarcity pricing and mitigation rules require changes to properly set prices when there are reliability unit commitments or other ERCOT reliability actions to manage transmission constraints; these changes should not disable rules for local market power mitigation.
- **Dispatch and Pricing for Local Reserve Scarcity:** A second step to price local scarcity and avoid out-of-market actions would be the introduction of local reserve requirements, implemented through co-optimization of the energy dispatch and reserve schedules, to properly set prices when there are constraints on reserve availability in a sub-region.

Transmission Planning and Cost Recovery

- **Transmission Planning:** Currently, out-of-market transmission planning occurs ahead of the development of scarcity and diminishes the scarcity price signals that would lead, in the alternative, to market-based investment. Market-reflective policies for transmission investment should be considered as a replacement for Texas' socialized transmission planning, which fails to provide the opportunity for markets to respond.
- **Transmission Cost Recovery:** The allocation of transmission charges based on peak period usage (4CP) leads to price suppression as well as welfare loss as market loads make expensive decisions to avoid allocations of sunk costs that cannot be avoided in the aggregate. Alternatives for transmission cost recovery to replace or reduce dependence on the summer peak demand-based mechanism for the allocation of sunk transmission costs would reduce distortion of energy market pricing.

2018 State of the Market Report for the ERCOT Electricity Markets

POTOMAC ECONOMICS

Independent Market Monitor
for ERCOT

June 2019

TABLE OF CONTENTS

controllable resources will grow. Hence, we continue to recommend that ERCOT develop this capability.

Status: We have been recommending this change since the start of ERCOT's nodal market. After taking interim steps to produce non-binding generation dispatch and price projections and then to improve the short term forecasting procedures, ERCOT evaluated the potential benefits of a multi-interval real-time market. This evaluation determined that, because the costs to implement were greater than the projected benefits, moving forward with implementation was not supported at the time.[9] The 2017 finding of insufficient benefits is not surprising given the low-price environment and the level of surplus capacity at the time of the evaluation.

However, with nearly 5 GW of fast-starting generation installed in ERCOT, ever increasing quantities of intermittent renewable resources, and the current lack of surplus capacity, the benefits of improving the short-term commitment process will grow. There is likely a much less costly option available to develop a process to optimize the commitment of fast-starting resources without implementing a full, multi-interval real-time market. Hence, we continue to recommend modifying the real-time market software to better commit load and 30-minute generators.

11. Evaluate policies and programs that create incentives for loads to reduce consumption for reasons unrelated to real-time energy prices, including: (a) the Emergency Response Service (ERS) program and (b) the allocation of transmission costs.

Any incentives that cause market participants to take actions that are inconsistent with the real-time prices will undermine the performance of the market and its prices. These concerns are heightened when these actions are taken under peak or emergency conditions because the ERCOT market relies on efficient pricing under such conditions to motivate efficient long-term resource decisions by participants. By curtailing load in response to incentives or programs that are not aligned with the real-time energy market, supply is uneconomically reduced and the real-time market is adversely affected. The following two aspects of the ERCOT market raise these concerns.

ERS Program. A load that wishes to actively participate in the ERCOT market can participate in ERS, provide ancillary services, or simply choose to curtail in response to high prices. Participating in ERS greatly limits a load's ability to provide ancillary services or curtail in response to high prices. Given the high budget allotted and the low risk of deployment, ERS is an attractive program for loads. Because the ERS program is so remunerative, we are concerned that it is limiting the motivation for loads to actively participate and contribute to price formation in the real-time energy market.

9 *See* PUCT Project No. 41837, *PUCT Review of Real-Time Co-Optimization in the ERCOT Region*, ERCOT Report on the Multi-Interval Real-Time Market Feasibility Study (Apr. 6, 2017).

Transmission Cost Allocation. Transmission costs in ERCOT are allocated on the basis of load contribution in the highest 15-minute system demand during each of the four months from June through September. This allocation mechanism is routinely referred to as four coincident peak, or 4CP. Transmission costs have doubled since 2012, significantly increasing an already substantial incentive to reduce load during probable peak intervals in the summer. ERCOT estimates that as much as 1500 MW of load were actively pursuing reduction during the 4CP intervals from 2016 to 2018.[10]

Load curtailment to avoid transmission charges may be resulting in price distortion during high load periods because the response is targeting peak demand rather than responding to wholesale prices. Even with higher prices in 2018, reductions were observed during June, July, and August at times with wholesale prices less than $40 per MWh.

Status: The Commission made no changes to the ERS program or transmission service rates in 2018.

12. Reserve the inclusion of marginal losses in ERCOT locational marginal prices for post-implementation of real-time co-optimization in ERCOT.

When electricity is produced in one location and consumed at another location, the electricity flows through the transmission system and some of it is lost. The transmission losses vary depending on the distance the electricity is traveling and the voltage of the lines it must flow over. Ideally, the real-time dispatch model should recognize the marginal losses that will result from dispatching units in different locations and set prices accordingly. Recognizing marginal losses will allow the real-time market to produce more from a higher-cost generator located electrically closer to the load, thus resulting in fewer losses. Optimizing this trade-off in the real-time dispatch lowers the overall costs of satisfying the system's needs.

The ERCOT market is unique in its treatment of transmission losses. Marginal losses are not included in ERCOT real-time energy prices and the costs of losses are collected from loads on an average basis. This approach may have been reasonable at the time ERCOT was implementing its initial real-time energy markets because generators were located relatively close to load centers. However, as open access transmission expansion policies and other factors have led to a wider dispersion of the generation fleet across the ERCOT footprint, the failure to recognize marginal losses in the real-time dispatch and pricing has led to larger dispatch inefficiencies and price distortions. Therefore, we are now recommending that the ERCOT real-time market be upgraded to recognize marginal losses in its dispatch and prices.

10 *See* ERCOT, 2018 Annual Report of Demand Response in the ERCOT Region (Mar. 2019) at 7, available at http://www.ercot.com/services/programs/load.

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program is defined by a Commission rule enacted in March 2012, which set a program budget of \$50 million.[28] The program was modified from a pay-as-bid auction to a clearing price auction in 2014, providing a clearer incentive to load to submit offers based on the costs to curtail, including opportunity cost. In 2016, the procurement for ERS shifted from four time periods per contract term to six time periods per contract term. The additional time periods were created to separate the higher risk times of early morning and early evening from the overnight and weekend hours. The time and capacity-weighted average price for ERS over the contract periods from February 2018 through January 2019 was \$6.72 per MWh, similar to the outcome of \$6.86 per MWh as the previous program year. For the first time since the inception of the program, this price was lower than the average price of \$9.20 per MWh paid for non-spinning reserves in 2018. The average price for non-spinning reserves in 2017 was much lower at \$3.18 per MWh. ERS was not deployed in either year.

Beyond ERS, there were slightly more than 250 MW of load participating in load management programs administered by transmission and distribution utilities in 2018.[29] Energy efficiency and peak load reduction programs are required by statute and Commission rule and most commonly take the form of load management, where participants allow electricity to selected appliances (typically air conditioners) to be curtailed.[30] These programs administered by transmission and distribution utilities may be deployed by ERCOT during a Level 2 Energy Emergency Alert (EEA).

Self-dispatch

In addition to active participation in the ERCOT market and ERCOT-dispatched reliability programs, loads in ERCOT can observe system conditions and reduce consumption accordingly. This response comes in two main forms. The first is by participating in programs administered by competitive retailers or third parties to provide shared benefits of load reduction with end-use customers. The second is through actions taken to avoid the allocation of transmission costs. Of these two methods, the more significant impacts are related to actions taken to avoid incurring transmission costs that are charged to certain classes of customers based on their usage at system peak.

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28 *See* 16 TAC § 25.507

29 *See* ERCOT 2018 Annual Report of Demand Response in the ERCOT Region (Mar. 2019) at 7, available at http://www.ercot.com/services/programs/load.

30 *See* PUCT Project 45675, *2016 Energy Efficiency Plans and Reports Pursuant to 16 TAC §25.181(n)*, SB 7. Section 39.905(a)(2) (http://www.capitol.state.tx.us/tlodocs/76R/billtext/html/SB00007I.htm)

For decades, transmission costs have been allocated on the basis of load contribution to the highest 15-minute system demand during each of the four months from June through September. This allocation mechanism is routinely referred to as four coincident peak, or 4CP. By reducing demand during peak periods, load entities seek to reduce their share of transmission charges. Transmission costs have doubled since 2012, increasing an already substantial incentive to reduce load during probable peak intervals in the summer.[31] ERCOT estimates that as much as 1700 MW of load were actively pursuing reduction during the 4CP intervals in 2018, an increase of about 200 MW from 2017.[32]

Voluntary load reductions to avoid transmission charges may be distorting prices during peak demand periods because the response is targeting peak demand rather than responding to wholesale prices. This was readily apparent in 2016 as there were significant load reductions corresponding to peak load days in June, July and September when real-time prices on those days were in the range of $25 to $40 per MWh. The trend continued in 2017, with significant reductions on peak load days in June, August and September when real-time prices were less than $100 per MWh. Even with higher prices in 2018, reductions were observed during June, July, and August at times with wholesale prices less than $40 per MWh.

Two factors in the ERCOT market continue to advance appropriate pricing actions taken by load in the real-time energy market. First, the initial phase of "Loads in SCED" was implemented in 2014, allowing controllable loads that can respond to 5-minute dispatch instructions to specify the price at which they no longer wish to consume. Although an important step, there are currently no loads qualified to participate in real-time dispatch. Second, the reliability adder, discussed in more detail in Section I: Review of Real-Time Market Outcomes, performs a separate pricing run of the dispatch software to account for the amount of load deployed, including ERS. Proposed changes to the calculation method of the reliability adder were discussed in 2018 in NPRR904, *Revisions to Real-Time On-Line Reliability Deployment Price Adder for ERCOT-Directed Actions Related to DC Ties*.[33]

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31 See PUCT Docket No 47777, Commission Staff's Application to Set 2018 Wholesale Transmission Service Charges for the Electric Reliability Council of Texas, Final Order (Mar. 29, 2018); PUCT Docket No. 46604, Commission Staff's Application to Set 2017 Wholesale Transmission Service Charges for the Electric Reliability Council of Texas, Final Order (Mar. 30, 2017); PUCT Docket No. 45382, Commission Staff's Application to Set 2016 Wholesale Transmission Service Charges for the Electric Reliability Council of Texas, Final Order (Mar. 25, 2016).

32 See ERCOT, 2018 Annual Report of Demand Response in the ERCOT Region (Mar. 2019) at 7, available at http://www.ercot.com/services/programs/load.

33 The primary flaw identified in the calculation method of the Real-Time On-Line Reliability Deployment Price Adder was that LDL relaxation made the price adders higher, even when the RUC-instructed Resource is being dispatched above LDL in the pricing run. The price adders fluctuated based on interval-to-interval changes in the system, including changes for Resources that were not RUC-instructed. HDL and LDL relaxation of Resources that were not RUC-instructed was intended to avoid ramp limitations that could exaggerate the pricing impacts of the out-of-market action.

TRANSCRIPT OF PROCEEDINGS

BEFORE THE

PUBLIC UTILITY COMMISSION OF TEXAS

AUSTIN, TEXAS

OPEN MEETING

THURSDAY, MAY 18, 2017

BE IT REMEMBERED THAT AT approximately 9:38 a.m., on Thursday, the 18th day of May 2017, the above-entitled matter came on for hearing at the Public Utility Commission of Texas, 1701 North Congress Avenue, William B. Travis Building, Austin, Texas, Commissioners' Hearing Room, before KENNETH W. ANDERSON, JR. and BRANDY MARQUEZ, Commissioners; and the following proceedings were reported by William C. Beardmore, Certified Shorthand Reporter.

the motions to dismiss.

COMM. ANDERSON: Well, I think we can revisit all of this once there's a ruling on your motion.

MR. BRAZELL: Thank you.

COMM. ANDERSON: All right. Item No. 8 has already been addressed. Item Nos. 9, 10 and 11 were consented.

Items 12 through 17, I believe, are not taken up --

AGENDA ITEM NO. 18

DISCUSSION AND POSSIBLE ACTION ON ELECTRIC RELIABILITY; ELECTRIC MARKET DEVELOPMENT; ERCOT OVERSIGHT; TRANSMISSION PLANNING, CONSTRUCTION, AND COST RECOVERY IN AREAS OUTSIDE OF ERCOT; SPP REGIONAL STATE COMMITTEE AND ELECTRIC RELIABILITY STANDARDS AND ORGANIZATIONS ARISING UNDER FEDERAL LAW

COMM. ANDERSON: -- which takes us to Item No. 18 that I would like to bring up an issue.

On May 10th of this year there was filed in a number of dockets by Calpine and NRG a report entitled "Priorities for the Evolution of the Energy-Only Electricity Design in ERCOT that was prepared by Dr. William Hogan and Dr. Susan Pope of FTI Consulting.

As most of you-all know, Dr. Hogan is also

Raymond Plank -- Raymond Plank, Professor of Global Energy Policy at the JFK School of Harvard, and was instrumental in assisting the Commission in the design of the operating reserve demand curve during our resource adequacy discussions of a few years back.

The report makes for a very interesting read. It looks at our market and analyzes its recent performance. While largely complimentary it does point out the challenges that are resulting from extended inexpensive natural gas and the dramatic expansion of intermittent renewable resources, the latter resulting largely but not exclusively from various federal incentives and other policies.

They offer a series of recommendations that might be considered in order to improve -- improve price formation in ERCOT's energy market, as well as to address the price impacts that sometimes occur as a result of operational -- of ERCOT's operation - operational activities.

At the heart of the report is a recognition that our market is premised - is premised foundationally on proper scarcity pricing.

The recommendations are sort of generally grouped into four buckets -- and that's my word -- not there's -- that are adjustments -- that are possible adjustments to the operating reserve demand curve.

There's the inclusion of marginal losses in pricing which is not done in ERCOT, although it's done in most of, I think, all the other organized markets.

There's the issue of co-optimization and in particular local scarcity pricing, and then there's some suggestions -- or analysis and suggestions around transmission planning and cost allocation of those.

I would -- if you would agree, I would like to work with Staff to bring back perhaps at the June Open Meeting whether through a memorandum or Staff product a -- some thoughts on what to do about this.

Sort of briefly, let me start by the fourth bucket, which is transmission planning cost recovery. I probably believe that it is not -- I'm going to ask that ERCOT in -- when we come back -- or when I come back with it that we get a status report on the transmission planning with a focus on what ERCOT has done to date.

That issue -- at the heart of that issue is the difference between the planning -- the planning horizon of transmission and the time it takes to build -- for IPPs to build generation in ERCOT.

The truth of the matter is, in ERCOT you can build power plants, you know, pretty quickly -- probably faster than just about anywhere else.

On the other hand, the transmission planning horizon is, you know, 8, 9, 10 years, again, even though in ERCOT we build it probably faster than anywhere else. That has created, I think, a bias.

I've talked about this before. This is a bias I think that we all recognize. We've talked about it. It was at the issue of a contested case a year or two back.

ERCOT has tinkered around the edges, but there's no consensus. And, frankly, nobody has been able to come -- at least has come to me with any really good suggestion. So perhaps -- and I think, as I recall, we directed ERCOT to go work on this with the stakeholders.

We've never really gotten the definitive answer back that "There is no answer, that the Commission needs to deal with it" or "it's just too difficult and there's nothing to be done."

But, whatever, that needs to be -- at least we need to report on that and then we need to know whether it's in our bailiwick or not.

With respect to cost allocation, I don't plan on taking that up, for one, if for no other reason than that it would require, I think, a change to law.

So we'd be, I think, wasting our time, one; two, moving off our current cost allocation methodology would be a move toward participant funding, and in my experience that's a recipe for no transmission or limited transmission being built.

So I would sort of put the transmission piece of this at a low or no priority; however, the first three buckets, I think, will merit some look.

Two issues dealt with in the adjustment to the -- or possible adjustments to the ORDC as well as local scarcity pricing deal with the effects that result from RMRs and RUCs, and, again, we've recognized this problem.

ERCOT is actually -- and the stakeholders have been addressing this, I think, a little too slowly. I think probably we're going to need to pick this up in order to get the ball moving a little faster.

I do think again that we'll be asking ERCOT though to do a report on what's been done, what is currently in the works and what remains to be done.

I would just note that, for example, among the things ERCOT is doing is giving their operators a lot more visibility and, therefore, encouraging them, in effect, to avoid unnecessary out-of-market dispatch.

definitely compliment Dr. Hogan and Dr. Pope on that report, but I thought that the illustration of just what folks are dealing with with the wind subsidies was one of the explanations of that issue that I've ever seen, and I want to get it to everybody because it's what -- in my mind that is going to be one of the challenges.

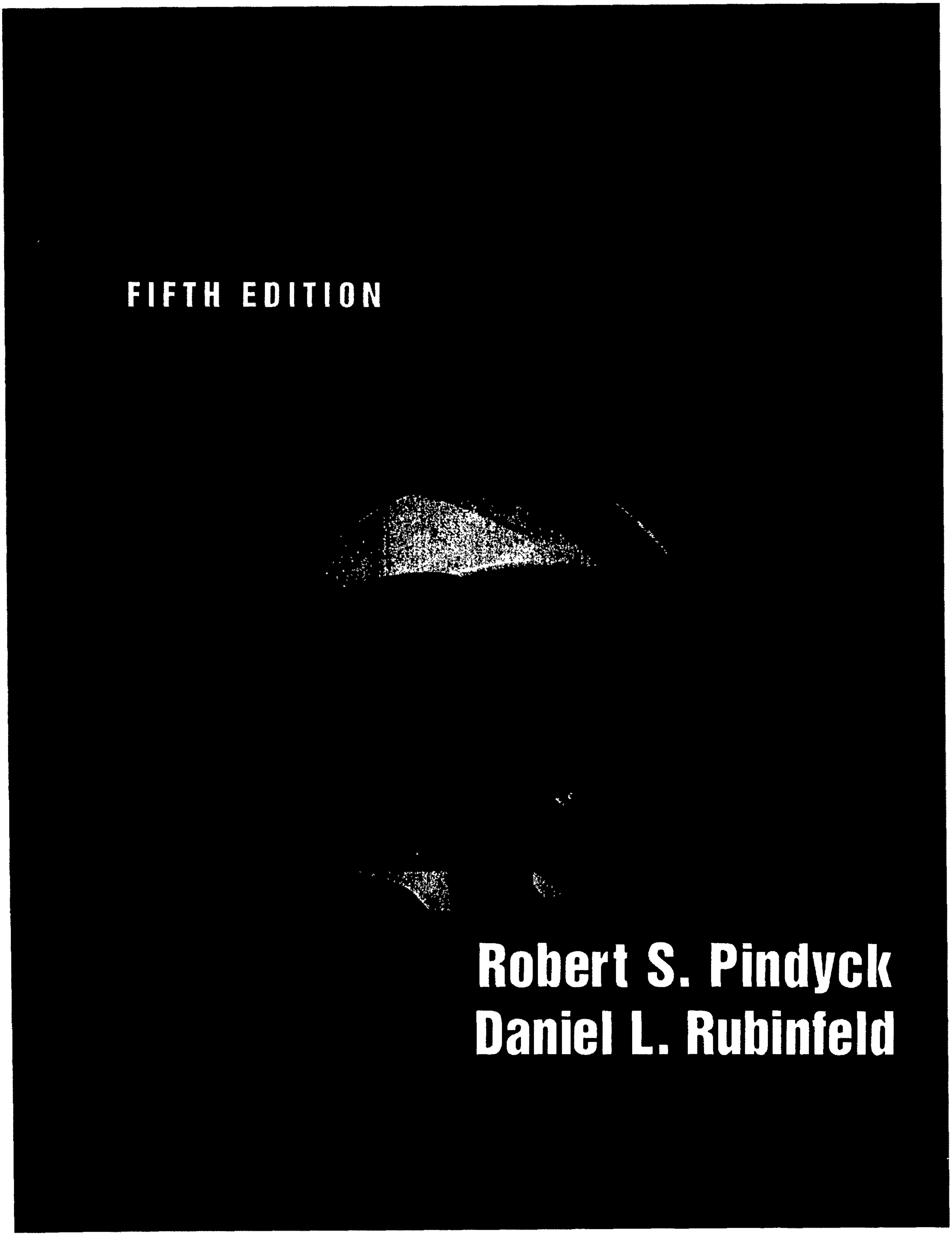
So I thought that their changes to ORDC are worth considering looking at. I did think that the conversation about the marginal losses was also interesting.

I know opening up SCED is never an easy thing. So it's something I think we should talk about process, but I don't know what way we would -- that what I'm saying, you know, can we look at all of these issues somewhat together? Maybe have -- maybe open up this project for comments on the paper.

You know, we have the transmission rule that's lingering out there as well which would probably be a more appropriate place to have some of the transmission conversations.

COMM. ANDERSON: Yeah. The transmission piece, I think, to me, that is a -- well, first off, I just don't think it's useful to talk about cost allocation.

On the planning piece, we can certainly do



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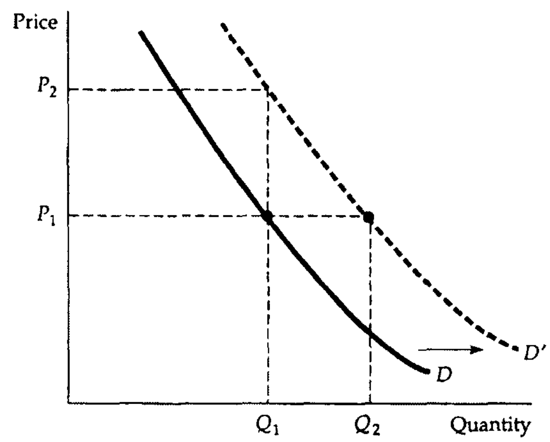

FIGURE 2.2 The Demand Curve

The demand curve, labeled D, shows how the quantity of a good demanded by consumers depends on its price. The demand curve is downward sloping; holding other things equal, consumers will want to purchase more of a good the lower is its price. The quantity demanded may also depend on other variables, such as income, the weather, and the prices of other goods. For most products, the quantity demanded increases when income rises. A higher income level shifts the demand curve to the right.

Of course the quantity of a good that consumers are willing to buy can depend on other things besides its price. *Income* is especially important. With greater incomes, consumers can spend more money on any good, and some consumers will do so for most goods.

Shifting the Demand Curve Let's see what happens to the demand curve if income levels increase. As you can see in Figure 2.2, if the market price were held constant at P_1, we would expect to see an increase in the quantity demanded—say, from Q_1 to Q_2, as a result of consumers' higher incomes. Because this increase would occur no matter what the market price, the result would be a *shift to the right of the entire demand curve.* In the figure, this is shown as a shift from D to D'. Alternatively, we can ask what price consumers would pay to purchase a given quantity Q_1. With greater income, they should be willing to pay a higher price—say, P_2 instead of P_1 in Figure 2.2. Again, *the demand curve will shift to the right.* As we did with supply, we will use the phrase *change in demand* to refer to shifts in the demand curve, and reserve the phrase *change in the quantity demanded* to apply to movements along the demand curve.[1]

substitutes Two goods for which an increase in the price of one leads to an increase in the quantity demanded of the other.

Substitute and Complementary Goods Changes in the prices of related goods also affect demand. Goods are **substitutes** when an increase in the price of one leads to an increase in the quantity demanded of the other. For example, copper and aluminum are substitute goods. Because one can often be substituted for the other in industrial use, *the quantity of copper demanded will increase if*

[1] Mathematically, we can write the demand curve as

$$Q_D = D(P,I)$$

where I is disposable income. When we draw a demand curve, we are keeping I fixed.

the price of aluminum increases. Likewise, beef and chicken are substitute goods because most consumers are willing to shift their purchases from one to the other when prices change.

Goods are **complements** when an increase in the price of one leads to a decrease in the quantity demanded of the other. For example, automobiles and gasoline are complementary goods. Because they tend to be used together, a decrease in the price of gasoline increases the quantity demanded for automobiles. Likewise, computers and computer software are complementary goods. The price of computers has dropped dramatically over the past decade, fueling an increase not only in purchases of computers, but also purchases of software packages.

complements Two goods for which an increase in the price of one leads to a decrease in the quantity demanded of the other.

We attributed the shift to the right of the demand curve in Figure 2.2 to an increase in income. However, this shift could also have resulted from either an increase in the price of a substitute good or a decrease in the price of a complementary good. Or it might have resulted from a change in some other variable, such as the weather. For example, demand curves for skis and snowboards will shift to the right when there are heavy snowfalls.

2.2 The Market Mechanism

The next step is to put the supply curve and the demand curve together. We have done this in Figure 2.3. The vertical axis shows the price of a good, P, again measured in dollars per unit. This is now the price that sellers receive for a given quantity supplied, and the price that buyers will pay for a given quantity demanded. The horizontal axis shows the total quantity demanded and supplied, Q, measured in number of units per period.

equilibrium (or market-clearing) price Price that equates the quantity supplied to the quantity demanded.

Equilibrium The two curves intersect at the **equilibrium,** or **market-clearing price** and quantity. At this price (P_0 in Figure 2.3), the quantity supplied and the quantity demanded are just equal (to Q_0). The **market mechanism** is the tendency in a free market for the price to change until the market *clears*—i.e., until

market mechanism Tendency in a free market for price to change until the market clears.

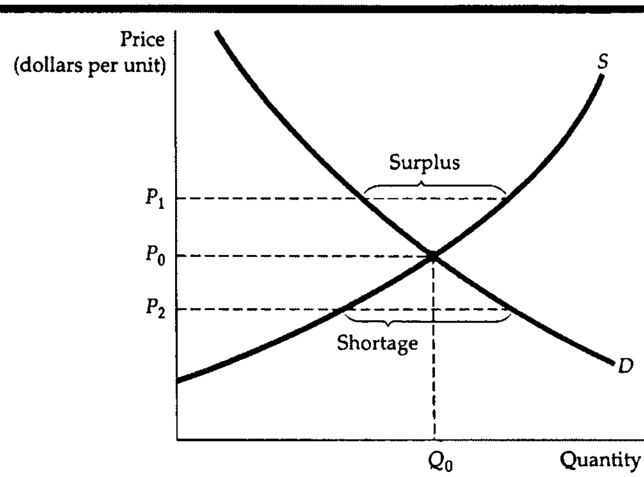

FIGURE 2.3 **Supply and Demand**

The market clears at price P_0 and quantity Q_0. At the higher price P_1, a surplus develops, so price falls. At the lower price P_2, there is a shortage, so price is bid up.

Principles of Public Utility Rates

Second Edition

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of ratemaking policy and as to the factual circumstances under which these objectives are sought to be attained. Attempts to make these stated principles subserve all special objectives and cover all specific conditions would be hopeless. Writers on the theory of rates are therefore at liberty to base their analyses on the acceptance of those objectives which are of wide application and the attainment of which may be aided by whatever tests or measures of sound rate structure the analyses suggest.

Among these objectives, the following three may be called primary, not only because of their widespread acceptance, but also because most of the more detailed objectives discussed in the literature are ancillary thereto: (1) the revenue-requirement, production-motivation, or financial-need objective; (2) the optimum-use, demand control, or consumer-rationing objective; and (3) the compensatory income transfer function or fair-cost-apportionment objective. Based on these objectives we propose the following three primary criteria by which to judge the soundness and desirability of a rate structure for public utility enterprises. As outlined below, these objectives are related closely to five of the ten attributes specified above.

Criterion 1 - Capital Attraction

(Attribute 1): based on the revenue-requirement objective, with due regard to potential problems of socially undesirable levels of rate base, product quality, and safety; it takes the form of a fair-return standard with respect to private utility companies;

Criterion 2 - Consumer Rationing

(Attributes 4 and 5): based on the consumer-rationing objective, under which the rates are designed to discourage the wasteful use of public utility services while promoting all use that is economically justified in view of the relationships between the private and social costs incurred and benefits received;

Criterion 3 - Fairness to Ratepayers

(Attributes 6 and 7): fair-cost-apportionment objective, which invokes the principle that the burden of meeting total revenue requirements must be distributed *fairly* and without arbitrariness, capriciousness, and inequities among the beneficiaries of the service and so as, if possible, to avoid undue discrimination.

The objectives specified above correspond to three of the four primary functions of utility rates set forth in Chapter 4. The efficiency-incentive function, or that of encouraging managerial efficiency, is