DOCKET NO. 22344

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	§ § § § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

ORDER NO. 40

INTERIM ORDER ESTABLISHING GENERIC CUSTOMER CLASSIFICATION AND RATE DESIGN

In Order No. 17, the Commission concluded that a uniform rate design and customer classification scheme is appropriate for the purpose of standardizing transmission and distribution rates in Texas.[1] This Order confirms that decision. In addition, based upon the evidence, briefs, and arguments of the parties, the Commission adopts a generic customer classification and rate design for transmission and distribution rates as more specifically described in this Order. As the Commission noted in the preliminary orders in the utility-specific unbundled-cost-of-service (UCOS) cases,[2] the resolution of an issue in this generic proceeding is to be applied in each utility's UCOS proceeding.

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[1] Order No. 17 at 10 (July 24, 2000).

[2] *Application of Sharyland Utilities, L.P. for Approval of Unbundled Cost of Service Rate Pursuant to PURA § 39.201 and P.U.C. SUBST. R. 25.344*, Docket No. 22348 (pending); *Application of Texas-New Mexico Power Company for Approval of Unbundled Cost of Service Rate Pursuant to PURA § 39.201 and P.U.C. SUBST. R. 25.344*, Docket No.22349 (pending); *Application of TXU Electric Company for Approval of Unbundled Cost of Service Rate Pursuant to PURA § 39.201 and P.U.C. SUBST. R. 25.344*, Docket No. 22350 (pending); *Application of Southwestern Public Service Company for Approval of Unbundled Cost of Service Rate Pursuant to PURA § 39.201 and P.U.C. SUBST. R. 25.344*, Docket No. 22351 (pending); *Application of Central Power & Light Company for Approval of Unbundled Cost of Service Rate Pursuant to PURA § 39.201 and P.U.C. SUBST. R. 25.344*, Docket No. 22352 (pending); *Application of Southwestern Electric Power Company for Approval of Unbundled Cost of Service Rate Pursuant to PURA § 39.201 and P.U.C. SUBST. R. 25.344*, Docket No. 22353 (pending); *Application of West Texas Utilities Company for Approval of Unbundled Cost of Service Rate Pursuant to PURA § 39.201 and P.U.C. SUBST. R. 25.344*, Docket No. 22354 (pending); *Application of Reliant Energy HL&P for Approval of Unbundled Cost of Service Rate Pursuant to PURA § 39.201 and P.U.C. SUBST. R. 25.344*, Docket No. 22355 (pending);

I. Introduction

In Order No. 3, the Commission requested parties to brief a number of issues, including whether the Commission should adopt a uniform classification scheme and rate design for transmission and distribution service.[3] After considering the parties' briefs, the Commission concluded that a uniform rate design and customer classification scheme is appropriate for the purpose of standardizing transmission and distribution (T&D) rates in Texas.[4] The Commission concluded, however, that resolution of this issue should await an evidentiary hearing where the Commission could evaluate the proposed customer classifications and rate designs.[5] This customer classification and rate design (CC/RD) phase of this proceeding satisfies this requirement.

Direct testimony in the CC/RD phase of this proceeding was filed by the parties on October 16, 2000, and rebuttal testimony was filed October 23, 2000. On November 2 and 3, 2000, the Commission heard evidence in connection with the establishment of generic customer classifications and rate design for use in the utilities' individual UCOS cases currently pending at the State Office of Administrative Hearings (SOAH). Initial and reply post-hearing briefs were filed by the parties on November 8 and 10, 2000, respectively. The Commission considered this matter in open meeting on November 16, 2000.

At the pre-hearing conference in the CC/RD phase of this proceeding held on October 31, 2000, the parties presented the administrative law judge with a decision point list for the Commission's convenience of reference in hearing the CC/RD phrase. The DPL was organized in a matrix format and provided a summary of each party's position on the issues to be heard in this phase. Following the hearing, the Policy Development Division (PDD) supplemented the DPL with summaries of each party's post-hearing brief, to the extent that such briefs differed from or elaborated on the pre-hearing DPL. During the November 16, 2000 open meeting, the Commission closely followed the

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Application of Entergy Gulf States, Inc. for Approval of Unbundled Cost of Service Rate Pursuant to PURA § 39.201 and P.U.C. SUBST. R. 25.344, Docket No. 22356 (pending);Hereinafter, individual UCOS cases.

[3] Order No. 3 at 4 (May 9, 2000).

[4] Order No. 17 at 10.

[5] *Id.*

format of the DPL. Subsequently, PDD added a section to the DPL that memorialized the Commission's rulings.

This Order does not provide a detailed discussion of each issue presented in the DPL, as the DPL consists of many distinct questions, some of which are rendered inapplicable given the Commission's rulings on related issues. However, each issue raised by the parties is addressed in the DPL. Accordingly, the DPL is appended to this Order as Attachment A to provide a more complete summary on each discrete issue presented.

II. Non-Unanimous Agreement on Customer Classification

On September 8, 2000, a Distribution Service Customer Classification Non-Unanimous Stipulation and Agreement (NUA) was filed in this proceeding by American Electric Power Company, Inc. (AEP); Texas-New Mexico Power Company (TNMP); TXU Electric Company (TXU); Southwestern Public Service Company (SPS); the Commission Staff of the Public Utility Commission of Texas (Commission Staff); Texas Industrial Energy Consumers (TIEC); Enron Energy Services, Inc. (Enron); and Texas Industries, Inc (TXI).[6] The following parties did not oppose the NUA: ALCOA and Floresville Electric Light and Power Systems.[7] The NUA, appended as Attachment B to this Order, addresses customer classifications for all of the utilities participating in this proceeding, including the NUA-signatory utilities (AEP, TNMP, TXU, SPS), Reliant Energy HL&P (Reliant), and Entergy Gulf States, Inc. (EGSI). Specifically, the NUA provides for the following six customer classes:

1. Residential
2. Secondary less than 10 kW or kVa (less than 5 kW for TNMP and EGSI)
3. Secondary greater than 10 kW or kVa (greater than 5 kW for TNMP and EGSI)
4. Primary
5. Transmission
6. Lighting

[6] Distribution Service Customer Classification Non-Unanimous Stipulation and Agreement at 2 (NUA).

[7] NUA at 1.

The Commission finds that the six customer classes as proposed in the NUA should be adopted by each of the utilities participating in this proceeding. The Commission agrees with the proponents of the generic customer classifications that cited cost causation as a significant factor in developing a uniform customer class configuration;[8] and, as a guiding principle, the need for flexibility in addressing reconciliation with the price to beat (PTB).[9] The adopted generic class design will best achieve these goals. Accordingly, the Commission adopts the six customer classes proposed in the NUA.

To recognize its unique characteristics, the Commission grants Sharyland Utilities, L.P. (Sharyland) an exemption from certain of the classifications. All of Sharyland's customers are equipped with interval data recorder (IDR) meters, obviating the need for classes to accommodate non-demand-metered customers.[10] Therefore, to the extent that such classes are unnecessary for Sharyland, a modified version of the NUA classes for Sharyland shall be addressed in its individual UCOS case.[11] This exemption does not, however, excuse Sharyland from meeting the underlying principles cited above. Additionally, Sharyland's classifications should mirror those in the NUA for demand-metered classes.

III. Generic Design of Transmission and Distribution Rates

In Order No. 17, the Commission stated that a uniform rate design was appropriate for the purposes of standardizing transmission and distribution rates in Texas.[12] As reflected in the DPL, the majority of the parties participating in this phase of the proceeding favored adoption of a generic design of transmission and distribution rates for all classes, with the exception of the lighting class. Because of the complexity of lighting rate design, as well as the variance in lighting tariffs among utilities, an attempt

[8] *See* Entergy Gulf States' (EGS) Initial Brief at 2-3; Nucor's Initial Brief at 3; Texas Industrial Electric Customers' (TIEC) Initial Brief at 5.

[9] *See* Cleco Connexus *et. al.*, Initial Brief at 1; Texas Retailers Association's (TRA) Initial Brief at 5.

[10] *See* Sharyland Statement of Position at 1.

[11] Docket No. 22348.

[12] Order No. 17 at 10.

to address lighting rate design would be impractical given the time constraints in this docket.[13]

The parties presented their positions through prefiled and live testimony as to the elements to be included in the generic transmission and distribution rate design. These elements included: (1) a customer charge; (2) a facilities/delivery charge; (3) ratchets; (4) kilovolt-ampere billing; (5) transmission cost recovery factor; (6) direct substation service; (7) a standby transmission rate; and (8) power factor correction formula. Those opposed to the generic rate design cited headroom, price signals, and intra-class variations as concerns.[14]

The Commission agrees with the proponents of a generic rate design 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.[15] Further, uniform transmission and distribution rates help to ensure a 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, consistent with this Order in the individual UCOS cases.

Additionally, the Commission agrees that adoption of a generic rate design for lighting is not realistic given the complexity of the topic. Accordingly, lighting rate design shall be addressed in the individual UCOS cases.

A. Customer Charge

The testimony in this proceeding revealed that the inclusion of a customer charge was generally favored by the parties. Specifically, these parties proposed that the customer charge be comprised of costs that are incurred regardless of system usage such

[13] *See* Commission Staff Direct Testimony of Pevoto at 14-15.

[14] *See* Reliant HL&P's (Reliant) Initial Brief at 9-10; City of Houston's Initial Brief at 6-7.

[15] *See* Southwestern Public Service Company's (SPS) Reply Brief at 6; American Electric Power Company's (AEP) Initial Brief at 4.

as billing, metering, and customer service.[16] One party maintained that customer charges should not be applied to the residential class because a fixed charge would discriminate against low use/low income customers.[17] With the exception of TXU, the parties were not opposed to having costs related to metering, which is expected to become a competitive service in the future, recovered through a separately stated charge.[18]

The Commission finds that the adoption of a uniform rate design that includes a customer charge is appropriate. Specifically, the customer charge shall be comprised of costs that vary by customer such as metering, billing and customer service.[19] A customer charge comprised of these elements appropriately tracks cost causation. Additionally, the metering portion of such charges, at a wholesale level, should be separately stated. This will facilitate the unbundling of metering charges when they become a competitive offering.

B. Facilities/Delivery Charge

Also considered in these proceedings was whether the generic rate design should include a facilities/deliveries charge. The majority of the parties maintain that a facilities/delivery charge is appropriate and that the manner in which the charge is to be recovered will be contingent on the metering capabilities of each customer. Because the residential and small commercial[20] classes typically do not have demand meters in place, the majority of the parties agree that a facilities/delivery charge should be recovered on a monthly per-kilowatt-hour (kWh) basis for these customers.[21] Many of the parties propose that demand-metered classes should be billed based on 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

[16] *See* Commission Staff's Initial Brief at 4-5.

[17] *See* Texas Legal Services Center's (TLS) Initial Brief at 5-7.

[18] *See* TXU Electric Company's (TXU) Initial Brief at 4-5.

[19] *See* Nucor's Initial Brief at 5; TXU's Initial Brief at 4.

[20] More properly, the secondary less than 10 kW or kVa (less than 5 kW for TNMP and Reliant) class.

[21] *See* Office of Public Utility Counsel's (OPUC) Reply Brief at 2; EGS's Initial Brief at 4.

locations. Parties opposing the use of a 4CP-billing determinant cited cost shifting and intraclass subsidies as the primary concerns.[22]

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.[23] 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. The interval for billing of demand charges shall be that interval which conforms to the protocols of the reliability council, power pool, or independent organization to which each utility belongs. For the majority of utilities participating in this proceeding, in accordance with Electric Reliability Council of Texas (ERCOT) protocols, a 15-minute demand interval shall be applied to demand charges. Finally, facilities/delivery charges shall be recovered on a per-kWh basis for residential and small commercial customers that do not have demand meters. The method established for the recovery of a facilities/delivery charge from each customer class, as detailed above, appropriately reflects the best-available metering data from each class, is a reasonable proxy for cost causation, and maintains continuity with past rate design methodology.

C. Ratchets

Nearly all of the parties recommended adoption of a demand ratchet in the distribution rates. The proponents maintained that ratchets stabilize utility revenues and that ratchets are an effective method to recover fixed distribution infrastructure costs. Those that opposed ratchets argued that they are not cost justified and place an excessive burden on low load factor customers. The parties' proposals ranged from an 80%

[22] *See* TXU's Initial Brief at 6.

[23] *See* P.U.C. SUBST. R. 25.192(c).

ratchet[24] to be applied to customers with demand charges to a 100% ratchet for all customer classes.[25] Most parties supported or were willing to accept an 85% ratchet for distribution rate classes with demand charges. In addition, parties generally agreed that an exception is appropriate for seasonal agriculture customers, based on testimony that applying a ratchet to these customers could result in charges higher than their current bundled rate on an annual basis.

The Commission finds that an 80% ratchet is appropriate for recovery of distribution costs from demand-metered customers. The Commission holds that although a 100% ratchet properly reflects the fixed nature of distribution costs, the 80% level more appropriately recognizes load diversity on the distribution system. The Commission acknowledges the unique characteristics of seasonal agricultural customers, and grants an exception to the establishment of generic ratcheted distribution demand charges for these customers; the design for each customer class that includes seasonal agricultural customers shall contain a provision for the recovery of distribution charges without the use of a demand ratchet for those customers.

D. KVA Billing

Interested parties agreed that the practice of billing on a per-kilovolt-ampere (kVA) basis should continue for a utility that has historically billed on a per-kVA basis. Proponents of this practice claimed that kVA billing sends customers the proper price signal to maintain a high power factor and obviates the need for power factor correction formula.[26] The proposed NUA classes allow this practice to continue.

The Commission agrees that kVA billing should continue as recognized by the NUA.

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[24] *See* Dallas-Fort Worth Hospital Council and the Coalition of Independent Colleges and Universities Initial Brief at 4-5.

[25] *See* AEP's Initial Brief at 9-10.

[26] *See* Reliant's Direct Testimony of Purdue at 15; Reliant's Initial Brief at 10.

E. TCRF

Proponents of a transmission cost recovery factor (TCRF) argued that a TCRF would be needed if the distribution utility were to act as the billing agent for transmission service providers. There were two general approaches proposed for such a mechanism. The first approach, proposed by Commission Staff, would allow a distribution utility to pass through to retail customers only the changes in ERCOT transmission costs approved by the Commission or allowed by P.U.C. SUBST. R. 25.193(a)(4).[27] The second approach would serve as a true-up mechanism to allow distribution utilities to adjust for under or over recovery of transmission costs. The latter approach would address the distribution utility's risk as a billing agent for transmission service providers.[28] Several parties argued there should be no TCRF, because such an automatic rate adjustment is prohibited by PURA.[29]

The Commission adopts the Commission Staff's methodology for a TCRF. The Commission agrees with Commission Staff that the TCRF should only be used to pass through wholesale transmission cost changes approved or allowed by the Commission. While this approach does not address the risk to the distribution utility for under and over collection of the transmission service charges, the Commission may take such risk into account when setting the distribution utility's rate of return.

F. Direct Substation Service

One party asserted that a separate rate for customers taking service directly out of the substation is warranted, on the grounds that these customers are basically the same as transmission-level customers with one additional transformation.[30] Opponents argued that such a rate would create a discrete class that would have significant impacts on other primary class customers.[31]

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[27] *See* Commission Staff's Direct Testimony of Pevoto at 26-29; Commission Staff's Initial Brief at 14.

[28] *See* AEP's Initial Brief at 12-14; Reliant's Initial Brief at 11-12. TXU's Initial Brief at 11-12.

[29] *See* City of Houston Direct Testimony of Daniel at 19. OPC's Initial Brief at 8.

[30] *See* TIEC Direct Testimony of Jeffry Pollock at 20-23.

[31] *See* TRA's Rebuttal Testimony of Saunders at 2-3; TXU's Rebuttal Testimony of Sherburne at 11-12.

The Commission concludes that a separate rate or adjustment for customers taking service directly out of the substation is not warranted. To establish a rate based on the location of a customer in relation to a substation represents a significant departure from longstanding ratemaking principles with respect to the shared costs of the distribution infrastructure. The Commission declines to institute a separate rate for customers who happen to be either closer to, or farther from, a particular substation.

G. Standby Transmission Rate

Proponents of a standby transmission rate argued that self-generating customers require transmission service only intermittently, and charging the same rate as for firm service would force standby customers to subsidize other customers. These parties also testified that standby customers are much less likely to use the transmission service during periods of system peak demand, and consequently, utilities do not need to build transmission capacity to serve their entire load. A few parties added that such a rate would support distributed generation. Opponents claimed that standby transmission service is not recognized under the Commission's transmission rules or the draft ERCOT protocols. They argued that such a rate is not cost-justified and would improperly shift costs to other customers. Opponents claimed that transmission investment is fixed and does not vary with usage. Some parties suggested that a standby rate should be a point of contract negotiation with the REP, not a pricing issue for regulated rates. Finally, some parties noted that a standby rate is unnecessary because coincident peak billing will recognize intermittent use by these customers.

The Commission declines to establish a standby rate for transmission service to be offered by the regulated transmission utility. Such a rate is more appropriately offered in the competitive market. Furthermore, assuming that standby customers do not take transmission service during peak periods, coincident peak billing for transmission service will recognize the intermittent usage of the transmission system by such customers.

H. Power Factor Correction Formula

The standard-power-factor-correction formula is being addressed in Project No. 22187.[32] Consequently, the Commission finds there is no need to consider this issue in this proceeding.

IV. Recovery of Transmission Charges

A. ERCOT

The Commission was presented, through pre-filed and live testimony, a number of models for the recovery of transmission charges within ERCOT. The options presented by the parties included (1) the "Order No. 14 model", (2) the "Staff Exhibit 3 model", and (3) the "Direct Billing model," as well as variations on each of these.

In Order No. 14, the Commission considered whether ERCOT transmission service providers (TSPs) should recover transmission costs by billing retail electric providers (REPs) for transmission service either directly or through an ERCOT settlement process, or by billing a distribution utility, which would in turn bill the REP.[33] There, the Commission concluded that the ERCOT TSPs should bill distribution utilities, which would then bill REPs a combined transmission and distribution charge.[34] Specifically, under the Order No. 14 model, each TSP would bill each distribution company based on its share of the ERCOT four coincident peaks (4CP). The distribution company would then bill each REP a combined transmission and distribution charge based on each REP's customer composition and billing determinants.[35]

Alternatively, under the Staff Exhibit 3 model, transmission costs for ERCOT utilities would be allocated on a 4CP basis, then collected from the REP, based on statewide rates, either through a distribution utility or through an ERCOT settlement

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[32] *Terms and Conditions of Transmission and Distribution Utilities' Retail Distribution Service,* Project No. 22187.

[33] Order No. 14 at 6-8.

[34] *Id.* at 9.

[35] *See* Commission Staff's Initial Brief at 7.

process.[36] Finally, the Direct Billing model contemplates that TSPs bill REPs for transmission service directly, without going through a distribution company or settlement procedure.[37]

The Commission affirms its conclusion articulated in Order No. 14 and as developed in detail by Commission Staff's testimony and briefs.[38] The Commission acknowledges that market participants have been developing the necessary processes to comply with Order No. 14 since its issuance, and agrees with Commission Staff that "altering the Order No. 14 model by substituting ERCOT as the settlement agent at this late date is impractical."[39]

B. Non-ERCOT

Non-ERCOT utilities generally agreed that the distribution delivery tariff should not include any transmission costs and that REPs should be wholesale purchasers of transmission service pursuant to Federal Energy Regulatory Commission (FERC) Open Access Transmission Tariffs.[40] Others argued that cost should be recovered in a manner similar to ERCOT utilities, with certain modifications.[41] In Order No. 17, the Commission decided that the FERC transmission rates for retail-access customers should be used where such a rate has been set. Otherwise, a rate would have to be calculated in the respective individual UCOS cases. This process will entail converting a FERC wholesale rate to a retail transmission rate based on the rate design adopted for residential and commercial customers.[42]

The Commission affirms its decision in Order No. 17 that transmission cost recovery for non-ERCOT utilities shall be consistent with the FERC Open Access

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[36] *See Id.* at 8.

[37] Order No. 14 at 6.

[38] *See* Commission Staff's Initial Brief at 7-13.

[39] *See Id.* at 10.

[40] *See* EGS's Initial Brief at 10; SPS's Initial Brief at 5-10.

[41] *See* AEP's Direct Testimony of Moncrief at 23-25.

[42] Order No. 17 at 9.

Transmission Tariff. Specific compliance with Order No. 17 shall be addressed in the individual UCOS cases.

V. Exceptions to Generic Customer Classification and Rate Design

Finally, the Commission was asked by the parties to consider a number of exceptions to generic customer classification and rate design. The requests included both those of a general nature, relating to the NUA classes and associated rate design, as well as specific questions regarding particular rates to be offered by individual utilities. Reliant requested a waiver from the NUA classes and generic rate design.

The Commission finds that exceptions to the generic customer classifications described in the NUA, other than that requested by Sharyland, are inappropriate and are hereby denied. Exceptions to the generic rate design established in this proceeding shall be considered in each utility's individual UCOS proceeding, only if necessary to address extraordinary impacts on the ability of customers to obtain service from a competitive provider due to the restrictions of the price to beat (i.e., "headroom" concerns). The Commission recognizes that a tension exists between two interests of the competitive market: the need for standardization and predictability among transmission and distribution service areas and the necessity of recognizing the headroom concerns unique to particular service areas. Furthermore, because the transmission and distribution rates addressed by this Order represent a relatively small proportion of an end-use customer's bill, the design of such rates shall be amended only in the case of exceptional headroom concerns. Such headroom concerns shall not, however, automatically mandate the granting of an exception to the generic rate design.

A. Rate XFMR

TXU proposed a separate rate (Rate XFMR) for its transmission utility to recover distribution-related costs associated with transformation service. TXU asserted that a separate rate is necessary because transformation service is a distribution-related charge and is therefore not eligible for inclusion in the transmission cost of service.

The Commission finds that a rate such as the proposed Rate XFMR is appropriate for the transmission utility to charge the distribution utility at wholesale. The distribution utility shall then include charges paid under this rate in its cost of service; a separate Rate XFMR or similar rate shall not be established for REPs or for end-use customers. The rate design of such a wholesale rate shall be conducted in TXU's individual UCOS case pending at SOAH.[43]

B. Primary Customers Without Demand Meters

Both TXU and SPS testified that, in their service areas, the primary class would include customers without a demand meter. Therefore, a separate rate design from that generically established for the primary class is necessary to accommodate these customers. TXU proposed to charge its customers based on a minimum demand charge of 5 kW, while SPS asserted that the billing demands should be determined through the load profiling process.

For primary class customers without demand meters, the Commission notes that the best solution would be for such customers to obtain demand meters. Recognizing the practical limitations of that solution, the Commission finds that an adaptation of the generic rate design to accommodate these customers shall be examined in each utility's individual UCOS case. The Commission recognizes that such customers are a small subset of the primary class and as such, within the narrow confines of this group of customers, determines that the use of load profiling to accomplish such an adaptation is appropriate.

[43] Docket No. 22350.

SIGNED AT AUSTIN, TEXAS the 22nd day of NOVEMBER, 2000.

PUBLIC UTILITY COMMISSION OF TEXAS

PAT WOOD, III, CHAIRMAN

JUDY WALSH, COMMISSIONER

BRETT A. PERLMAN, COMMISSIONER

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