§25.242(f)(1)(B) continued

available, the electric utility shall inform the qualifying facility within 30 days after being notified for distribution interconnection, or within 60 days for transmission interconnection, giving the qualifying facility a description of the additional facilities required as well as cost and schedule estimates for construction of such facilities. If an agreement to purchase energy is not reached upon completion of construction of the interconnection facilities or 90 days after notification by the qualifying facility that such energy is or will be available, the agreement, if and when achieved, shall bear a retroactive effective date for the purchase of energy delivered to the electric utility correspondent with the time of interconnection or the 90th day, whichever is later. Nothing in this subsection shall be construed in a manner that would preclude a qualifying facility from notifying and contracting for energy with a utility for sale of energy prior to 90 days before delivery of such energy.

(C) Each PTB REP shall purchase energy from a qualifying facility with a design capacity of 100 kilowatts or more within a timely fashion after being notified by the qualifying facility that such energy is or will be available.

(2) **Obligation to sell to qualifying facilities.** In accordance with subsection (k) of this section, each electric utility shall sell any energy and capacity requested to any qualifying facility located within the electric utility's service area. Each PTB REP shall also sell any energy requested to any qualifying facility; however, those sales shall be at market based rates. Nothing shall restrict the ability of any qualifying facility to purchase energy from any REP.

(3) **Interconnection.** Interconnection by a qualifying facility is addressed by Subchapter I, Division 1, of this chapter (relating to Transmission and Distribution) if the interconnection is to a transmission system and by §25.211 of this title (relating to Interconnection of On-site Distributed Generation) if the interconnection is to a distribution system, except if the interconnection is regulated by the Federal Energy Regulatory Commission.

(4) **Transmission to other electric utilities.** Transmission service provided by an electric utility in the ERCOT power region to a qualifying facility shall be governed by Subchapter I of this chapter.

(5) **PTB REP and scheduling with qualifying facilities.** A PTB REP shall use dynamic resource scheduling or responsibility transfer in ERCOT with any qualifying facility that requests such scheduling, as permitted by ERCOT. The PTB REP's cost of using dynamic resource scheduling or responsibility transfer attributable solely to purchases from qualifying facilities shall be charged to qualifying facilities that use such scheduling. If a qualifying facility uses static scheduling, the qualifying facility shall bear the costs for any imbalances resulting from the qualifying facility's failure to submit a schedule or to comply with the schedule.

(g) **Rates for purchases from a qualifying facility.**

(1) Rates for purchases of energy and capacity from any qualifying facility shall be just and reasonable to the customers of the electric utility or PTB REP and in the public interest, and shall not discriminate against qualifying cogeneration and small power production facilities.

(2) Rates for purchases of energy and capacity from any qualifying facility shall not exceed avoided cost. Rates for purchase shall be based upon a market-based determination of avoided costs over the specific term of the contract or other legally enforceable obligation, the rates for such purchase do not violate this subsection if the rates for such purchase differ from avoided cost at the time of delivery. Payments which do not exceed avoided cost shall be found to be just and reasonable operating expenses of the electric utility.

<u>§25.242(g) continued</u>

(3) A QF may agree to commit, on a day-ahead basis, to deliver firm power for the next day to a PTB REP. Rates for purchase of this power shall be based on prices for the day that the power was actually delivered as reported or published in an independent third party index or survey of trades of commonly traded power products in ERCOT, provided that the index or survey is ERCOT-specific and is based upon enough transactions to represent a liquid market, and the commitment to deliver shall correspond with the relevant hours of delivery of those products.

(h) **Standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less.**

(1) There shall be included in the tariffs of each electric utility standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less. The rates for purchases under this paragraph:

(A) shall be consistent with subsection (g) of this section, as it concerns purchases from a qualifying facility;

(B) shall consider the aggregate capacity value provided by multiple qualifying facilities with a design capacity of 100 kilowatts or less; and

(C) may differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies.

(2) Terms and conditions unique to qualifying facilities with a design capacity of 100 kilowatts or less such as metering arrangements, safety equipment requirements, liability for injury or equipment damage, access to equipment and additional administrative costs, if any, shall be included in a standard tariff.

(3) The standard tariff shall offer at least the following options:

(A) parallel operation with interconnection through a single meter that measures net consumption;

(i) net consumption for a given billing period shall be billed in accordance with the standard tariff applicable to the customer class to which the user of the qualifying facility's output belongs;

(ii) net production will not be metered or purchased by the utility and therefore there will be no additional customer charge imposed on the qualifying facility;

(B) parallel operation with interconnection through two meters with one measuring net consumption and the other measuring net production;

(i) net consumption for a given billing period shall be billed in accordance with the standard tariff applicable to the customer class to which the user of the qualifying facility's output belongs;

(ii) net production for a given billing period shall be purchased at the standard rate provided for in paragraph (1)(A) and (B) of this subsection;

(C) interconnection through two meters with one measuring all consumption by the customer and the other measuring all production by the qualifying facility;

(i) all consumption by the customer for a given billing period shall be billed in accordance with the standard tariff applicable to the customer class to which the customer would belong in the absence of the qualifying facility;

(ii) all production by the qualifying facility for a given billing period shall be purchased at the standard rate provided for in paragraph (1)(A) and (B) of this subsection.

<u>§25.242(h) continued</u>

(4) In addition, each electric utility shall offer qualifying facilities using renewable resources with an aggregate design capacity of 50 kilowatts or less the option of interconnecting through a single meter that runs forward and backward.
   (A) Any consumption for a given billing period shall be billed in accordance with the standard tariff applicable to the customer class to which the user of the qualifying facility's output belongs.
   (B) Any production for a given billing period shall be purchased at the standard rate provided for in paragraph (1)(A) of this subsection.
   (C) This option is not available if a contract for interconnection or the purchase of electricity is executed after December 31, 2008.

(5) Interconnection requirements necessary to permit interconnected operations between the qualifying facility and the utility and the costs associated with such requirements shall be dealt with in a manner consistent with Subchapter I of this chapter.

(6) The rates, terms and conditions contained in the standard tariff for qualifying facilities with a design capacity of 100 kilowatts or less shall be subject to review and revision by the commission.

(7) Except for qualifying facilities subject to §25.217 of this title (relating to Distributed Renewable Generation) requirements for the provision of insurance under this subsection shall be of a type commonly available from insurance carriers in the region of the state where the customer is located and for the classification to which the customer would belong in the absence of the qualifying facility. An enhancement to a standard homeowner's or farm and ranch owner's policy containing adequate liability coverage and having the effect of adding the electric utility as an additional insured or named insured is one means of satisfying the requirements of this paragraph. Such policies shall in each instance be on a form approved or promulgated by the Texas Department of Insurance and issued by a property or casualty insurer licensed to do business in the State of Texas.

(i) **Tariffs setting out the methodologies for purchases of nonfirm power from a qualifying facility.** Tariffs setting out the methodologies for purchases of nonfirm power from a qualifying facility shall be filed with the commission based on one of the following approaches:

(1) Rates for purchases of nonfirm power may, by agreement of both the electric utility and the qualifying facility, be based on the utility's average avoided energy costs. Administrative, billing, and metering costs shall be recovered through a monthly customer charge to the qualifying facility.

(2) PTB REPs and QFs may mutually agree to rates for purchases of nonfirm power that differ from the rates described in paragraph (4) of this subsection. Any such agreements shall be made on a nondiscriminatory basis. Such agreements may include provisions to prevent the potential for arbitrage.

(3) Rates for purchases of nonfirm power may, at the option of the qualifying facility, be based on the full cost at the time of delivery of decremental energy that would have been incurred by the electric utility had the qualifying facility not been in operation.
   (A) The following factors should be considered in the calculation of the cost of decremental energy:
      (i) fuel costs;
      (ii) variable operating and maintenance costs;
      (iii) line losses;
      (iv) heat rates;

§25.242(i)(3)(A) continued

(v) cost of purchases from other sources;
(vi) other energy-related costs;
(vii) capacity costs, if, as a class, qualifying facilities providing nonfirm energy offer some predictable capacity; and
(viii) for short term energy purchases, the time and quantity of energy furnished.

(B) If practical, the avoided cost should be determined by calculating by time period, using the utility's economic dispatch model (or comparable methodology), the difference between the cost of the total energy furnished by both the qualifying facility and the utility, computed as though the energy furnished by the qualifying facility had been furnished by the utility, and the actual cost of energy furnished by the utility.

(C) The economic dispatch model should take into consideration the following factors:
(i) fuel costs;
(ii) variable operating and maintenance costs;
(iii) line losses;
(iv) heat rates;
(v) purchased power opportunity;
(vi) system stability; and
(vii) operating characteristics.

(D) Time periods should be hourly if the utility has an automated economic dispatch model available; otherwise the shortest reasonable time period for which costs can be determined should be used.

(E) Administrative, billing, and metering costs shall be recovered through a monthly customer charge to the qualifying facility.

(4) Rates for purchases of nonfirm power shall be based on the market price of energy at the time of sale from the QF unless other arrangements have been made in accordance with paragraph (2) of this subsection. Administrative, billing, and metering costs shall be recovered through a monthly customer charge to the qualifying facility. Such agreements may include provisions to prevent the potential for arbitrage.

(j) **Periods during which purchases not required.**

(1) Any PTB REP or electric utility which gives notice to each affected qualifying facility in time for the qualifying facility to cease delivery of energy or capacity to the PTB REP, or electric utility will not be required to purchase electric energy or capacity during any period during which, due to operational circumstances, including resource ramp rate limitations that could cause imbalances or the amount of energy put by the QF exceeds the PTB REP's load, purchases from qualifying facilities will result in costs greater than those which the electric utility would incur if it did not make such purchases, but instead generated an equivalent amount of energy itself, provided, however, that this subsection does not override contractual obligations of the PTB REP or electric utility to purchase from a qualifying facility.

(2) Any PTB REP or electric utility which fails to give notice to each affected qualifying facility in time for the qualifying facility to cease the delivery of energy or capacity to the PTB REP or electric utility will be required to pay the same rate for such purchase of energy or capacity as would be required had the period of greater costs not occurred.

(3) A claim by PTB REP or an electric utility that such a period has occurred or will occur is subject to such verification by the commission either before or after the occurrence.

§25.242 continued

(k) **Rates for sales to qualifying facilities.**

(1) General rules.

(A) Rates for sales to qualifying facilities shall be just and reasonable and in the public interest, and shall not discriminate against any qualifying facility in comparison to rates for sales to other customers served by the electric utility. Rates for standby or other supplementary service shall be based on the amount of capacity contracted for between the qualifying facility and the electric utility, and shall not penalize electric utilities that also purchase power from qualifying facilities. The need for and cost responsibility for special equipment or system modifications shall be determined by application of Subchapter I of this chapter.

(B) Rates for sales that are based on accurate data and consistent system-wide costing principles shall not be considered to discriminate against any qualifying facility to the extent that such rates apply to the electric utility's other customers with similar load or other cost-related characteristics.

(2) Additional services to be provided to qualifying facilities.

(A) Upon request of a qualifying facility within its service area, each electric utility shall provide:

(i) supplementary power;
(ii) back-up power;
(iii) maintenance power; and
(iv) interruptible power.

(B) An electric utility shall not be required to provide supplementary power, back-up power, or maintenance power to a qualifying facility if the commission finds that provision of such power will:

(i) impair the electric utility's ability to render adequate service to its customers; or
(ii) place an undue burden on the electric utility.

(3) Rates for sales of back-up power and maintenance power. The rate for sales of back-up power or maintenance power:

(A) shall not be based upon an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak, or both; and

(B) shall take into account the extent to which scheduled outages of the qualifying facilities can be usefully coordinated with scheduled outages of the utility's facilities.

(l) **System emergencies.**

(1) **Qualifying facility obligation to provide power during system emergencies.** A qualifying facility shall be required to provide energy or capacity to an electric utility during a system emergency only to the extent:

(A) provided by agreement between such qualifying facility and electric utility; or
(B) ordered under the Federal Power Act, §202(c).

(2) **Discontinuance of purchases and sales during system emergencies.** During any system emergency, an electric utility may discontinue:

(A) purchases from a qualifying facility if such purchases would contribute to such emergency; and

(B) sales to a qualifying facility, provided that such discontinuance is on a nondiscriminatory basis.

§25.242 continued

(m) **Enforcement.** A proceeding to resolve a dispute between an electric utility, PTB REP and a qualifying facility arising under this section may be instituted by filing of a petition with the commission. Electric utilities, PTB REPs, and qualifying facilities are encouraged to engage in alternative dispute resolution prior to the filing of a complaint.

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Eastman Cogeneration Facility | Power Plant Profile

Owner	Ultimate Parent	Operating Capacity Ownership (%)	Planned Capacity Ownership (%)
Eastman Chemical Co.	Eastman Chemical Co.	100 000	-

Operator
Eastman Cogen LP

Site Information

City or County	Harrison County
State, Province, or Admin Region	Texas
Country	USA
NERC Region and Subregion	MRO/MRO-US (100.00%)
ISO or TSO	SPP (100.00%)
Planning Area	Southwest Power Pool Inc (1
Balancing Authority	Southwest Power Pool Inc (1
Interconnected Utility	Southwestern Electric Power
Water Source	Ferguson Lake

Plant Description

Operating Status	Operating
Current Operating Capacity (	448 1
Prime Mover	Combined Cycle
Primary Fuel	Natural Gas
Secondary Fuel	Waste Heat
Fuel Group(s)	Gas, Other Nonrenewable
Co-Fired Units?	No
Fuel Switching Units?	No
Year First Unit in Service	2001
Cogenerator?	Yes
Offshore?	No
Regulatory Status	Merchant Unregulated

Summary Operating Data - 2019

Operating Capacity (MW)	448 1
Net Generation (MWh)	2,472,403
Heat Rate (Btu/kWh)	5,673
Capacity Factor (%)	62 99
Total Operating & Maintenance Expense per MWh ($/MWh	17 73

Unit Details

				Capacity (MW)				
Unit Name	Generation Technology	Technology Detail	Unit Nameplate Capacity (MW)	Summer Net Capacity (MW)	Winter Net Capacity (MW)	Primary Fuel	Operating Status	Online Date
GEN1	Combined Cycle Combustion Turbine (CT)	NA	170 0	153 7	168.3	Natural Gas	Operating	Apr - 2001
GEN2	Combined Cycle Combustion Turbine (CT)	NA	170 0	146 2	159 8	Natural Gas	Operating	Jul - 2001
GEN3	Combined Cycle Combustion Steam (CA)	NA	127 7	109 8	120 0	Natural Gas	Operating	Jul - 2001

S&P Global Market Intelligence guarantees coverage of operational power plant units that file data with the EIA or are larger than 1 MW in North America, and 5

Due to the variability of sources reporting values on in-development projects, S&P Global Market Intelligence accuracy on the following fields is guaranteed to
S&P Global Market Intelligence guarantees coverage on Power Purchase Agreements for plants first tracked after Jan - 2011 and with a unit greater than 100 M

S&P Global
Market Intelligence

Eastman Cogeneration Facility | Generation Chart (Data)

Reporting Level: Entire Plant
Frequency: Monthly
Period· 7 Years

Period As Of	*Net Generation (MWh)*	*Capacity Factor (%)*	
12/31/2013	158,902	48.58	
1/31/2014	189,197	57.85	
2/28/2014	150,171	50.83	
3/31/2014	18,315	5.60	
4/30/2014	116,986	36.96	
5/31/2014	175,237	53.58	
6/30/2014	159,842	50.50	
7/31/2014	184,637	56.45	
8/31/2014	195,405	59.75	
9/30/2014	181,576	57.37	
10/31/2014	198,162	60.59	
11/30/2014	200,393	63 31	
12/31/2014	186,784	57.11	
1/31/2015	224,505	68.64	
2/28/2015	206,633	69.95	
3/31/2015	132,775	40.60	
4/30/2015	155,806	49.23	
5/31/2015	200,368	61.26	
6/30/2015	189,398	59.84	
7/31/2015	205,039	62.69	
8/31/2015	194,897	59.59	
9/30/2015	178,920	56.53	
10/31/2015	158,081	48 33	
11/30/2015	204,584	64.64	
12/31/2015	200,666	61 35	
1/31/2016	173,544	53.06	
2/29/2016	170,162	55.62	
3/31/2016	167,259	51.14	
4/30/2016	204,841	64.72	
5/31/2016	196,514	60.08	
6/30/2016	199,758	63.11	
7/31/2016	194,995	59.62	
8/31/2016	202,269	61.84	
9/30/2016	207,219	65.47	
10/31/2016	217,131	66.39	
11/30/2016	228,525	72.20	
12/31/2016	196,111	59.96	
1/31/2017	188,768	57.72	
2/28/2017	176,960	59.90	
3/31/2017	189,150	57.83	

4/30/2017	209,572	66.21
5/31/2017	168,021	51.37
6/30/2017	172,551	54.52
7/31/2017	206,973	63.28
8/31/2017	195,116	59.66
9/30/2017	169,801	53.65
10/31/2017	57,047	17.44
11/30/2017	117,286	37.06
12/31/2017	167,030	51.07
1/31/2018	202,044	60.60
2/28/2018	188,223	62.51
3/31/2018	181,395	54.41
4/30/2018	192,318	59.61
5/31/2018	205,461	61.63
6/30/2018	186,710	57.87
7/31/2018	216,240	64.86
8/31/2018	197,204	59.15
9/30/2018	165,955	51.44
10/31/2018	135,290	40.58
11/30/2018	153,050	47.44
12/31/2018	169,831	50.94
1/31/2019	224,361	67 30
2/28/2019	215,640	71 61
3/31/2019	183,153	54.94
4/30/2019	178,734	55.40
5/31/2019	218,568	65.56
6/30/2019	208,663	64.68
7/31/2019	220,077	66 01
8/31/2019	193,738	58.11
9/30/2019	172,104	53.34
10/31/2019	214,238	64.26
11/30/2019	188,648	58 47
12/31/2019	254,479	76.33
1/31/2020	221,221	66 36
2/29/2020	242,173	77 65
3/31/2020	248,055	74.40
4/30/2020	171,062	53 02
5/31/2020	205,480	61.63
6/30/2020	213,416	66 15
7/31/2020	220,417	66 11
8/31/2020	216,410	64.91
9/30/2020	197,633	61.26
10/31/2020	69,605	20.88
11/30/2020	224,431	69.56
12/31/2020	221,617	66.47

ELECTRIC UTILITY COST ALLOCATION MANUAL

NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS

January, 1992

B. Energy Weighting Methods

There is evidence that energy loads are a major determinant of production plant costs. Thus, cost of service analysis may incorporate energy weighting into the treatment of production plant costs. One way to incorporate an energy weighting is to classify part of the utility's production plant costs as energy-related and to allocate those costs to classes on the basis of class energy consumption. Table 4-4 shows allocators for the example utility for total energy, on-peak energy, and off-peak energy use.

In some cases, an energy allocator (annual KWH consumption or average demand) is used to allocate part of the production plant costs among the classes, but part or all of these costs remain classified as demand-related. Such methods can be characterized as partial energy weighting methods in that they take the first step of allocating some portion of production plant costs to the classes on the basis of their energy loads but do not take the second step of classifying the costs as energy- related.

1. Average and Excess Method

Objective: The cost of service analyst may believe that average demand rather than coincident peak demand is a better allocator of production plant costs. The average and excess method is an appropriate method for the analyst to use. The method allocates production plant costs to rate classes using factors that combine the classes' average demands and non-coincident peak (NCP) demands.

Data Requirements: The required data are: the annual maximum and average demands for each customer class and the system load factor. All production plant costs are usually classified as demand-related. The allocation factor consists of two parts. The first component of each class's allocation factor is its proportion of total average demand (or energy consumption) times the system load factor. This effectively uses an average demand or total energy allocator to allocate that portion of the utility's generating capacity that would be needed if all customers used energy at a constant 100 percent load factor. The second component of each class's allocation factor is called the "excess demand factor." It is the proportion of the difference between the sum of all classes' non-coincident peaks and the system average demand. The difference may be negative for curtailable rate classes. This component is multiplied by the remaining proportion of production plant -- i.e., by 1 minus the system load factor -- and then added to the first component to obtain the "total allocator." Table 4-10A shows the derivation of the allocation factors and the resulting allocation of production plant costs using the average and excess method.

TABLE 4-10A

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE AVERAGE AND EXCESS METHOD

Class Rate	Demand Allocation Factor - NCP MW	Average Demand (MW)	Excess Demand (NCP MW - Avg. MW)	Average Demand Component of Alloc. Factor	Excess Demand Component of Alloc. Factor	Total Allocation Factor (%)	Class Production Plant Revenue Requirement
DOM	5,357	2,440	2,917	17.95	18.51	36.46	386,683,685
LSMP	5,062	2,669	2,393	19.64	15.18	34.82	369,289,317
LP	3,385	2,459	926	18.09	5.88	23.97	254,184,071
AG&P	572	254	318	1.87	2.02	3.89	41,218,363
SL	126	58	68	0.43	0.43	0.86	9,101,564
TOTAL	14,502	7,880	6,622	57.98	42.02	100.00	$1,060,476,000

Notes: The system load factor is 57.98 percent, calculated by dividing the average demand of 7,880 MW by the systen coincident peak demand of 13,591 MW. This example shows production plant classified as demand-related.

Some columns may not add to indicated totals due to rounding.

If your objective is -- as it should be using this method --to reflect the impact of average demand on production plant costs, then it is a mistake to allocate the excess demand with a coincident peak allocation factor because it produces allocation factors that are identical to those derived using a CP method. Rather, use the NCP to allocate the excess demands.

The example on Table 4-10B illustrates this problem. In the example, the excess demand component of the allocation factor for the Street Lighting and Outdoor Lighting (SL/OL) class is negative and reduces the class's allocation factor to what it would be if a single CP method were used in the first place. (See third column of Table 4-3.)

TABLE 4-10B

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE AVERAGE AND EXCESS METHOD (SINGLE CP DEMAND FACTOR)

Rate Class	Demand Allocation Factor - Single CP NCP MW	Average Demand (MW)	Excess Demand (Single CP MW - Avg. MW)	Average Demand Component of Allocation Factor	Excess Demand Component of Allocation Factor	Total Allocation Factor (%)	Class Production Plant Revenue Requirement
DOM	4,735	2,440	2,295	17.95	16.89	34.84	369,461,692
LSMP	5,062	2,669	2,393	19.64	17.61	37.25	394,976,787
LP	3,347	2,459	888	18.09	6.53	24.63	261,159,089
AG&P	447	254	193	1.87	1.42	3.29	34,878,432
SL	0	58	-58	0.43	-0.43	0.00	0
TOTAL	13,591	7,880	5,711	57.98	42.02	100.00	$1,060,476,000

Notes: The system load factor is 57.98 percent, calculated by dividing the average demand of 7,880 MW by the systen coincident peak demand of 13,591 MW. This example shows all production plant classified as demand-related. Note that the total allocation factors are exactly equal to those derived using the single coincident peak method shown in the third column of Table 4-3.

Some columns may not add to indicated totals due to rounding.

Some analysts argue that the percentage of total production plant that is equal to the system load factor percentage should be classified as energy-related and not demand-related. This could be important because, although classifying the system load factor percentage as energy-related might not affect the allocation among classes, it could significantly affect the apportionment of costs within rate classes. Such a classification could also affect the allocation of production plant costs to interruptible service, if the utility or the regulatory authority allocated energy-related production plant costs but not demand-related production plant costs to the interruptible class. Table 4-10C presents the allocation factors and production plant revenue requirement allocations for an average and excess cost of service study with the system load factor percentage classified as energy-related.

4. The Single Non-Coincident Peak (NCP) Demand Allocation Method

The NCP method attempts to give recognition to the maximum demand placed upon a system during the year by all customers. This method is based on the theory that facilities are sized to meet these maximum demands. Therefore, the costs of the facilities are allocated in accordance with each customer's contribution to the sum of the maximum demands of all customers' imposed on the facilities.

Customer responsibility under this method is computed as follows:

$$\text{Customer Group NCP Demand Ratio} = \frac{\text{Cust Group NCP Metered Demand + Demand Losses}}{\text{Transmission System NCP Demand}}$$

Data for individual customers such as municipal or cooperative systems is usually readily available by delivery point. The maximum peak demands of individual or groups of retail customers are not available since many retail loads are not demand metered. Thus, large groups of retail customers will benefit from the diversity among their loads in the allocation process. See Table 5-5 for a sample application of the single NCP allocation methodology.

TABLE 5-5

EXAMPLE OF SINGLE NON-COINCIDENT PEAK DEMAND ALLOCATION

Customer group NCP demand (MW)	520
System NCP demand*	15842
Customer group NCP demand ratio	.03282

* Assuming a coincidence factor of .95 for the system, NCP for CP demand of 15050 MW would equal 15842 MW.

5. The Monthly Average NCP Demand Allocation Method

The monthly average NCP demand allocation method attempts to give recognition to the variation or diversity among monthly NCP demands placed on a system during the year by all customers. This in effect recognizes the fact that facilities are installed to provide reliable service throughout the year including periods of scheduled maintenance. Costs of the facilities are allocated in accordance with each customer's average monthly contribution to the sum of the average monthly maximum demands of all customers.

As with the NCP method, data for individual customers such as municipal or co-operative systems is usually readily available by delivery point. The maximum peak demands of individual or groups of retail customers are not available since many retail loads are not demand metered. See Table 5-6 for sample application of monthly average NCP allocation methodology.

TABLE 5-6

EXAMPLE OF MONTHLY AVERAGE NCP DEMAND ALLOCATION

Customer group NCP demand total(MW)	4778
System NCP demand total*	150347
Customer group monthly average NCP demand ratio	.03178

* Assuming a coincidence factor of .95 for the system, NCP for system CP monthly demands as shown in Table 5-1 would total 150347 MW.

6. Average and Excess Allocation Method

In contrast to the various peak demand allocation methods which assign costs based entirely on peak demand responsibility, under the average and excess demand allocation method (A&E) transmission costs are divided into two parts for allocation purposes on both demand and energy based on the system load factor (the ratio of the average load over a designated period to the peak demand occurring in that period). As such, the A&E method emphasizes or recognizes the extent of the use of capacity resulting in allocation of an increasing proportion of capacity costs to a customer group as its load factor increases. This theory implies that a utility's capacity serves a dual function -- while system peak demands establish the level of capacity, providing continuous service creates additional incentive for such capacity costs. Use of the A&E method for allocating transmission costs is typically employed for consistency when production costs are allocated on the same basis.

Because the A&E method does not recognize the coincident peak contribution of a customer group's load, the data necessary to perform the calculation is limited to the energy consumption and maximum (non-coincident) demand for a given period.

The first half of the formula, the "average" component representing the customer group's average energy consumption, allocates transmission costs on an energy use or average demand basis. The second half of the formula, the "excess" component is derived from the difference between the customer group's maximum non-coincident peak demand and the "average" demand component. The A&E method is expressed algebraically as follows:

$$D = L \times \frac{A}{B} + (1-L) \times \frac{C}{E}$$

Where: D = customer group's demand responsibility ratio
L = system's annual load factor
A = customer group's energy requirements
B = total system energy requirements
C = customer group's "excess" demand responsibility
E = sum of all customer groups' "excess" demand responsibility

Implementation problems associated with the A&E method are inherent in the complexity of the computation. Additional complications may arise in an attempt to recognize that demand meter readings are not taken on a consistent basis, e.g., a large bulk power customer may reflect a greater degree of diversity as compared to a smaller low voltage distribution customer with little or no diversity. See Table 5-7 for sample application of average and excess allocation methodology.

TABLE 5-7

EXAMPLE OF AVERAGE AND EXCESS DEMAND ALLOCATION

$$D = L \times \frac{A}{B} + (1-L) \times \frac{C}{E}$$

Where: D = customer group's demand responsibility ratio
L = system's annual load factor = $\frac{\text{average load for year}}{\text{peak load for year}}$

$$= \frac{\dfrac{\text{70470 million KWH (Table 5-1)}}{\text{8784 hrs/yr}}}{\text{15,050,000 KW (Table 5-1)}} = 53.3\%$$

A = customer group's energy requirements = 2449 million KWH assuming monthly load factor of 70%
B = total system energy requirements = 70,470 million KWH
(1-L) = 46.5%
C = customer group's "excess" demand responsibility

$$= \text{520 MW (Table 5-1)} - \frac{\text{2449 million KWH}}{\text{8784 hrs in 1988}} = \text{241 MW}$$

E = 15842 MW (Table 5-1 CP demand for system at .95 coincidence factor) - $\frac{\text{70470 million KWH}}{\text{8784 hrs in 1988}}$

= 7819 MW

Therefore: $D = (53.3\%) \dfrac{2449 \times 10^6}{70,470 \times 10^6} + (46.7\%) \dfrac{\text{241 MW}}{\text{7819 MW}} = .032917$

7. Combination of Other Methods

The preceding discussions have addressed situations involving allocation of various firm transmission investments to firm power loads. Depending on the factual situation present on a utility's system, it may be appropriate to employ a combination of methods to properly allocate cost responsibility to customers. Thus, an NCP allocation is sometimes used to allocate subtransmission costs, while a peak responsibility method based on coincident demands is used for the higher order transmission facilities. In addition, where certain customers may exhibit load patterns that are not adequately represented in their coincident load data, other factors not normally employed in a peak responsibility method may need to be introduced to assure proper cost allocation.

With regard to non-firm transmission services, while it may or may not be true that such services should not be held responsible for any demand costs, it should also be recognized that non-firm services require very close analysis of service contract provisions to determine utility obligations in order to establish the correct basis for allocation.

B. Direct Assignment

The costs of specific transmission facilities, such as long radial transmission lines and substations, may be directly assigned to particular customers. Direct assignments of such costs implies that the facilities can be considered entirely apart from the integrated system. In fact, the case for the independence of the facilities must be unequivocal since the customer must be willing to bear all the costs of service that, due to the unintegrated character of the facilities, may be just as high for service that is less reliable than service on the integrated system.

Costs assigned directly to customers are often collected via a special facilities charge. The charge can reflect: (1) the installed costs of the facilities; or (2) the average system cost of such facilities.

The plant costs that are directly assigned to a customer group must be excluded from the utility's total transmission plant costs for allocation. Alternatively, the revenue can be treated for costing as a revenue credit.

SPP Southwest Power Pool

SPP PLANNING CRITERIA

Revision 2.3

Maintained by:

TRANSMISSION WORKING GROUP
SYSTEM PROTECTION AND CONTROLS WORKING GROUP
SUPPLY ADEQUACY WORKING GROUP

Published on 1/11/2021

3. INTRODUCTION

The Planning Criteria developed by SPP provide background information, guidelines, business rules, and processes for the operation and administration of the SPP Planning Process.

4. PLANNING RESERVE MARGIN

The Planning Reserve Margin ("PRM") shall be twelve percent (12%). If a Load Responsible Entity's Firm Capacity is comprised of at least seventy-five percent (75%) hydro-based generation, then such PRM shall be nine point eight nine percent (9.89%).

Determination of the PRM will be supported by a probabilistic Loss of Load Expectation ("LOLE") Study, which will analyze the ability of the Transmission Provider to reliably serve the SPP Balancing Authority Area's forecasted Peak Demand. The LOLE study will be performed in accordance with Attachment AA of the SPP OATT.

4.1 DEFINITIONS

4.1.1 LOAD RESPONSIBLE ENTITY

As defined in Attachment AA of the SPP OATT.

4.1.2 FIRM CAPACITY

As defined in Attachment AA of the SPP OATT.

4.1.3 PEAK DEMAND

As defined in Attachment AA of the SPP OATT.

5. REGIONAL TRANSMISSION PLANNING

5.1 CONCEPTS

For the purposes of Section 5 of the SPP Criteria the transmission system shall be defined as facilities under the functional control of the SPP Open Access Transmission Tariff (OATT) or the Bulk Electric System (BES). The transmission system shall be capable of performing reliably under a wide variety of expected system conditions while continuing to operate within equipment and electric system thermal, voltage, and stability limits. The transmission system, at a minimum, shall be planned to withstand all single element contingencies and maintenance outages over the load conditions of all applicable seasonal models as required for each planning process. Extreme event contingencies which measure the robustness of the electric systems should be evaluated for risks and consequences. The NERC Reliability Standards define specific requirements where adherence provides a measurable degree of reliability for the BES. SPP provides additional coordinated regional transmission planning requirements to promote reliability through this Criterion and related "Transmission Planning Process" (Attachment O) in the OATT.

5.2 DEFINITIONS

All capitalized terms shall have their meaning as contemplated in the SPP OATT or NERC Glossary of Terms used in the NERC Reliability Standards, unless defined below or noted within this document.

Nominal Voltage – The root-mean-square, phase-to-phase voltage by which the system is designated and to which certain operating characteristics of the system are related. Examples of nominal voltages are 500 kV, 345 kV, 230 kV, 161 kV, 138 kV, 115 kV and 69 kV.

The definition of Material Modifications is used for purposes of evaluating changes to existing Bulk Electric System (BES) interconnections of transmission Facilities for NERC Reliability Standard FAC-002-2 compliance. If one or more Material Modifications criterion are met, SPP shall analyze these changes to meet the requirements of NERC FAC-002-2 as the Planning Coordinator. Any change outside of this definition may be submitted to the Planning Coordinator for evaluation.

Material Modifications are permanent changes (that are typically greater than 12 months) to BES transmission Facilities. These permanent changes include:

1) Reduction to a BES transmission Facility's Normal Rating or Emergency Rating greater than 20% (derate);
2) Proportional changes to the magnitude of the BES transmission Facility's impedance that is greater than +/- 30% from its original positive sequence impedance value;
3) Changes in operating voltage of a BES transmission Facility;
4) Changes in BES transmission Facility system configuration including the connection or disconnection of new or existing BES transmission Facilities;
5) Changes in BES transmission Facility system protection that would reduce fault-interrupting capability or fault-clearing expediency for events that are included in the SPP Annual data request.

PUC DOCKET NO. 46449
SOAH DOCKET NO. 473-17-1764

RECEIVED
2018 MAR 19 PM 3:18
PUBLIC UTILITY COMMISSION
FILING CLERK

APPLICATION OF SOUTHWESTERN ELECTRIC POWER COMPANY FOR AUTHORITY TO CHANGE RATES	§ § §	PUBLIC UTILITY COMMISSION OF TEXAS

ORDER ON REHEARING

This order addresses the application of Southwestern Electric Power Company (SWEPCO) for authority to change its rates, filed on December 16, 2016. SWEPCO originally sought a $69 million increase to its Texas retail revenue requirement, primarily to reflect investments in environmental controls. However, SWEPCO also proposed a significant modification to the manner in which its transmission costs should be recovered. In addition, SWEPCO sought additional cost recovery for vegetation management, rate-case expenses, and a regulatory asset for certain costs under the Southwest Power Pool's open-access tariff.

A hearing on the merits was held between June 5 and June 15, 2017 at the State Office of Administrative Hearings (SOAH). On September 22, 2017, the SOAH administrative law judges (ALJs) filed their proposal for decision (PFD) in which they recommended a Texas retail revenue requirement increase of approximately $51 million. The SOAH ALJs rejected SWEPCO's new method to recover transmission costs and recommended granting its requested rate-case expenses, and regulatory asset. In response to parties' exceptions and replies to the PFD, on November 8, 2017, the SOAH ALJs filed a letter making changes to the PFD.

Except as discussed in this order, the Commission adopts the PFD as modified, including findings of fact and conclusions of law. The Commission's decisions result in a Texas retail base-rate revenue requirement of $369,234,023, which is an increase of $50,001,133 from SWEPCO's present Commission-authorized Texas retail base-rate revenue requirement. New findings of fact 17A through 17J are added to address the procedural history of this docket after the close of the evidentiary record at SOAH. The Commission incorporates by reference the abbreviations table provided in the PFD.

625

in CWIP will decrease capitalized ad valorem taxes. Staff's recommendation does not consider this change.

Meter Reading Expense

265. SWEPCO's total-company test-year level of meter-reading expenses, $614,613, is reasonable.

266. Labor-cost savings associated with the deployment of advanced meters are captured by the test-year-ending-head-count adjustment employed by SWEPCO.

Dues and Contributions

267. SWEPCO did not oppose OPUC witness William Marcus's proposal to reduce the company's total-company dues and contributions expense by $45,100. Subject to that reduction, SWEPCO's dues and contributions expense is reasonable.

Green Country Capacity Purchase

268. The request for proposals (RFP) that resulted in the signing of the Green Country PPA sought bids to supply up to 200 MW of capacity and associated energy for a term of three to five years beginning June 1, 2016. Potential bidders were notified by the issuance of a public news release, and the RFP documents were available on the SWEPCO web site. After evaluating the resulting proposals, an agreement was reached for capacity, energy, and related ancillary services from the Green Country Energy Facility.

269. As part of meeting its load-serving-entity obligation in the SPP, SWEPCO had no choice but to purchase capacity, as it would have otherwise been short of the required capacity under SPP planning criteria.

270. It was prudent for SWEPCO to enter into the Green Country PPA.

Weather Normalization

271. Weather data are not randomly distributed by year. There can be weather trends, including both warming and cooling trends.

272. The use of a 30-year period for normalizing weather is not a reasonable means of capturing such trends.

273. The use of 10 years of data is a reasonable means of capturing such weather trends.

274. The use of 10 years of data is more sensitive to weather patterns during the test year.

275. The weather-normalization adjustment should be applied to adjust billing units and allocation factors for a 10-year weather-normalization period, based on the class billing determinants and external allocation factors used to calculate rates using a 10-year weather-normalization period.

Jurisdictional Cost Allocation

276. SWEPCO's proposal to base the jurisdictional allocation of transmission capacity costs on the 12 Coincident Peak (12CP) methodology is reasonable and consistent with Commission precedent.

Cost Allocation

Allocation of Production Costs

277. SWEPCO allocates production costs to various classes under the average and excess Demand-4 coincident peak (A&E-4CP) methodology. This methodology allocates a percentage of costs, equal to the system load factor, based on average demand, and the remainder of those costs based on excess demand.

278. In SPS Docket No. 43695, the only Commission docket in which this issue has been litigated, the Commission determined that the system load factor should be calculated by using the single annual coincident peak, rather than the average of four coincident peaks.

279. SWEPCO used the single coincident peak in calculating its system load factor for Schedule O-1.6.

280. The use of the annual coincident peak in calculating system load factor is consistent with the definition of load factor in the Commission's rules.

281. The use of the annual coincident peak for calculating system load factor is consistent with SWEPCO's generation and transmission planning.

282. The use of the annual coincident peak for calculating system load factor is consistent with the National Association of Regulatory Commissioners (NARUC) manual.

283. The use of the annual coincident peak for calculating system load factor is consistent with SPP planning.

284. In using the A&E-4CP methodology, SWEPCO should calculate its system load factor using the single annual coincident peak.

Class Cost Allocation of Transmission Costs

285. SWEPCO proposes to allocate transmission costs to retail classes based on the 12CP demand allocator.

286. SWEPCO is a summer-peaking utility.

287. The electricity demands in the summer months are the primary drivers for the amount of transmission capacity needed for SWEPCO to provide reliable service.

288. SWEPCO's demands during the four summer months ranged from 4623 MW to 5149 MW, while no off-peak month had demand in excess of 4051 MW.

289. The Commission has a longstanding policy of allocating transmission costs based primarily on peak demands in the four summer months.

290. SWEPCO has submitted the same position in support of the 12CP methodology in this case that it did in its prior case.

291. In Docket No. 40443, the Commission rejected SWEPCO's proposal to allocate transmission costs based on the 12CP methodology, and instead required SWEPCO to use the A&E/4CP methodology.

292. The A&E/4CP method for allocating transmission costs to the retail classes is standard and the most reasonable methodology.

293. SWEPCO should use the A&E/4CP method for allocating transmission costs to the retail classes.

Major Customer Account Representative Expense

294. A major account representative is a utility employee who provides services either to large customers or to national chains.

295. During the test year, SWEPCO (total company) spent $1,082,908 on major account representatives.

296. SWEPCO uses major account representatives to work with 69 large commercial and 68 industrial customers.

297. It is reasonable to allocate major-account-representatives expenses solely to the large commercial and industrial customers who benefit from that service.

298. Major account representative costs should not be assigned to residential and general-service customers who do not receive these services.

299. Allocating the costs of major-account-representatives to the large commercial and industrial customers is consistent with cost-causation principles.

300. Assigning a weighting factor reflecting the 69 large commercial and 68 industrial customers who receive the service is reasonable to properly allocate the costs of the major-account representatives to these classes.

301. Applying a new allocation factor to Account 908 that correctly reallocates major-account-representative costs to the Large Commercial and Industrial Classes is appropriate.

302. Allocating the $369,336 (Texas retail) of major-account-representative expenses to the Large Commercial and Industrial Classes is reasonable.

Uncollectible Expense Allocation

303. Uncollectible expenses are caused by non-paying former customers, and the current customers in a particular class are not the cause of uncollectible expense created by other former members of that class.

304. No paying customer regardless of class contributed more to these costs than any other paying customer.

305. It is reasonable to allocate the uncollectible expenses broadly across all classes based on revenue.

Primary/Secondary Distribution Split for Accounts 364 and 365

306. SWEPCO proposes to allocate costs in FERC Accounts 364 and 365 between the primary and secondary distribution systems based on the "investment method," which splits the cost based on the investment used to provide primary and secondary distribution services.

Southwestern Electric Power Company
System Information
April 2019 - March 2020

(1) Net System Dependable Capacity	(2) Unavailable Capacity due to Scheduled Maintenance	(3) Net Available Capacity	(4) Monthly System Peak		Date	Day of the Week	Hour Ending	(5) Reserve Without Scheduled Maintenance	(6) Reserve Including Scheduled Maintenance
		(1) - (2)						(1) - (4)	(3) - (4)
5,110	2,152	2,958	3,245	Apr	4/2/2019	3	8	1,865	(287)
5,085	462	4,623	3,854	May	5/23/2019	5	17	1,231	769
5,085	0	5,085	4,307	Jun	6/21/2019	6	16	778	778
5,085	0	5,085	4,436	Jul	7/17/2019	4	17	649	649
5,085	0	5,085	4,727	Aug	8/12/2019	2	16	358	358
5,089	0	5,089	4,493	Sep	9/6/2019	6	16	596	596
5,108	692	4,416	4,209	Oct	10/2/2019	4	16	899	207
5,137	1,590	3,547	4,063	Nov	11/13/2019	4	8	1,074	(516)
5,158	625	4,533	3,900	Dec	12/18/2019	4	9	1,258	633
5,162	0	5,162	3,590	Jan	1/21/2020	3	9	1,572	1,572
5,154	0	5,154	3,713	Feb	2/7/2020	6	9	1,441	1,441
5,135	960	4,175	2,930	Mar	3/26/2020	5	17	2,205	1,245

Sponsored by: Chad Burnett

System Information
April 2017 - March 2018

(1) Net System Dependable Capacity	(2) Unavailable Capacity due to Scheduled Maintenance	(3) Net Available Capacity	(4) Monthly System Peak		Date	Day of the Week	Hour Ending	(5) Reserve Without Scheduled Maintenance	(6) Reserve Including Scheduled Maintenance
		(1) - (2)						(1) - (4)	(3) - (4)
5,192	1,710	3,482	3,332	Apr	4/28/2017	6	17	1,860	150
5,166	109	5,057	3,824	May	5/31/2017	4	17	1,342	1,233
5,166	110	5,056	4,405	Jun	6/16/2017	6	17	761	651
5,166	0	5,166	4,769	Jul	7/20/2017	5	17	397	397
5,166	0	5,166	4,537	Aug	8/22/2017	3	17	629	629
5,170	696	4,474	4,422	Sep	9/20/2017	4	17	748	52
5,189	767	4,422	4,297	Oct	10/9/2017	2	17	892	125
5,219	613	4,606	3,267	Nov	11/6/2017	2	16	1,952	1,339
5,240	71	5,169	3,894	Dec	12/31/2017	1	21	1,346	1,275
5,244	71	5,173	4,792	Jan	1/17/2018	4	9	452	381
5,232	436	4,796	3,907	Feb	2/8/2018	5	9	1,325	889
5,213	991	4,222	3,171	Mar	3/8/2018	5	8	2,042	1,051

Sponsored by: Chad Burnett

Southwestern Electric Power Company
System Information
April 2018 - March 2019

(1) Net System Dependable Capacity	(2) Unavailable Capacity due to Scheduled Maintenance	(3) Net Available Capacity	(4) Monthly System Peak		Date	Day of the Week	Hour Ending	(5) Reserve Without Scheduled Maintenance	(6) Reserve Including Scheduled Maintenance
		(1) - (2)						(1) - (4)	(3) - (4)
5,188	1,556	3,632	2,972	Apr	4/16/2018	2	8	2,216	660
5,168	774	4,394	4,355	May	5/30/2018	4	17	813	39
5,168	0	5,168	4,641	Jun	6/28/2018	5	16	527	527
5,168	0	5,168	4,834	Jul	7/19/2018	5	17	334	334
5,168	0	5,168	4,563	Aug	8/16/2018	5	17	605	605
5,172	723	4,449	4,451	Sep	9/19/2018	4	16	721	(2)
5,191	1,914	3,277	3,895	Oct	10/4/2018	5	17	1,296	(618)
5,215	857	4,358	3,813	Nov	11/15/2018	5	8	1,402	545
5,236	785	4,451	3,760	Dec	12/11/2018	3	9	1,476	691
5,162	0	5,162	4,090	Jan	1/24/2019	5	9	1,072	1,072
5,154	0	5,154	3,945	Feb	2/8/2019	6	9	1,209	1,209
5,135	473	4,662	4,148	Mar	3/5/2019	3	8	987	514

Sponsored by: Chad Burnett

Southwestern Electric Power Company
System Information
April 2016 - March 2017

(1) Net System Dependable Capacity	(2) Unavailable Capacity due to Scheduled Maintenance	(3) Net Available Capacity	(4) Monthly System Peak		Date	Day of the Week	Hour Ending	(5) Reserve Without Scheduled Maintenance	(6) Reserve Including Scheduled Maintenance
		(1) - (2)						(1) - (4)	(3) - (4)
5,726	2,504	3,222	3,409	Apr	4/27/2016	4	16	2,317	(187)
5,689	1,988	3,701	3,845	May	5/25/2016	4	17	1,844	(144)
5,684	702	4,982	4,623	Jun	6/16/2016	5	17	1,061	359
5,684	360	5,324	4,906	Jul	7/21/2016	5	17	778	418
5,684	360	5,324	4,921	Aug	8/4/2016	5	17	762	402
5,688	26	5,662	4,477	Sep	9/19/2016	2	17	1,211	1,185
5,707	1,599	4,108	3,933	Oct	10/6/2016	5	16	1,774	175
5,729	1,834	3,895	3,317	Nov	11/2/2016	4	16	2,411	577
5,769	160	5,609	4,364	Dec	12/19/2016	2	9	1,405	1,245
5,244	50	5,194	4,419	Jan	1/7/2017	7	9	825	775
5,236	520	4,716	3,395	Feb	2/16/2017	5	9	1,841	1,321
5,217	1,182	4,035	3,326	Mar	3/14/2017	3	8	1,891	709

Sponsored by: Chad Burnett

SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' SECOND REQUEST FOR INFORMATION

Question No. TIEC 2-1:

Please provide each of the listed files, which are linked to in the as-filed native Schedules and Workpapers, as fully functional "live" workbooks in EXCEL format with all external links and formulas intact. For ease of reference, a spreadsheet showing the native Schedules and Workpapers in which each of the listed files is linked to is provided with this request as Attachment 1.

a. [WP G-5, G-5.1, G-5.1a, G-5.1b (Legislative Advocacy).xls.
b. 2020_3 FERC_BS1 -- SWEPCO Corp Consolidated.xls.
c. AEP Consolidated (with Elim Spread) - 2018 Appt. Summary.xlsx.
d. AEPSC-Schedule G-4 (2020) (4.1 and 4.2 only).xls.
e. AEPSC-Schedule G-4 (2020) (4.3).xls.
f. Copy of Coal Inventory 13 Month Values.xlsx.
g. Copy of J (Cash Flow) 06302016.xlsx.
h. Copy of SWEPCO Rev Detail TYE_Mar_2020.xlsx.
i. DD Dump.xls.
j. Demand Energy Fuel Split 2019 True Up.xlsx.
k. For Tax- RCEXP ADIT.xlsx.
l. G-7 - Federal Income Tax.xlsx.
m. Historical Customer Counts.xlsx.
n. J - SWEPCO Consolidated Stmt Change Eq Comp Income 6-30-16.xlsx.
o. Labor 2020.xlsx.
p. Schedule H-6.3b Workpaper.xlsx.
q. Schedule II Compare Rates SEP TX 2019 0917.xlsx.
r. Schedule Q-7 Proof of Revenue.xlsx.
s. Summary of Test Year Production O&M).xlsx.
t. SWEPCo - T-Lock (09.12.18 Settlement) Amortization Schedule_FINAL (2).xls.m
u. SWEPCO 03-31-2020 WCOC.xlsx.
v. SWEPCO AR Billing Determinates - TYE 20200331.xlsx.
w. SWEPCO AR Rates for Cust Adj.xlsx.
x. SWEPCO LA Billing Determinates - TYE 20200331.xlsx.
y. SWEPCO LA Rates for Cust Adj.xlsx.
z. SWEPCO Misc Rev TYE Mar 2020.xlsx.
aa. SWEPCO STATE Loads0419-0320.xlsx.
bb. SWEPCO TX Billing Determinates - TYE 20200331.xlsx.
cc. SWEPCO TX COS_Class TY 3_2020.xlsx.

dd. SWEPCO TYE 3-31-20.xlsx.
ee. SWEPCO Wholesale Billing Determinates - TYE 20200331.xlsx.
ff. SWP Fcst Data for Schedules.xlsx.
gg. SWT Data for Sch O-10.xls.
hh. T Johnson Ad Valorem WP A-3.13.1 (Ad Valorem) 20200331.xlsx.
ii. Texas Schedules TYE 6-2016.xlsx.
jj. WP A-3.13 (Gross Receipts and PUCT Assessment).XLS.
kk. WP A-3.23 (Int Calc).xls.
ll. WP A-3.27 (Fuel Adjustment Workpaper).xlsx.
mm. WP E-4 (Cash Working Capital).xlsx.
nn. WP G-5,G-5.1,-5.1a,G-5.1b (Legislative Advocacy,etc).xls.

Response No. TIEC 2-1:

a. Excel file provided as Highly Sensitive.
b. Excel file provided electronically with this response.
c. Excel file provided as Highly Sensitive.
d. Excel file provided electronically with this response.
e. Excel file provided electronically with this response.
f. Excel file provided as Highly Sensitive.
g. Excel file provided electronically with this response.
h. Excel file provided electronically with this response.
i. Excel file provided electronically with this response.
j. Excel file provided electronically with this response.
k. Excel file provided electronically with this response.
l. G-7 – Federal Income Tax.xlsx provided electronically with this response includes the correct version of Schedule G-7.3 as addressed in the Company's clarification filing made on October 22, 2020 with the PUC.
m. Excel file provided electronically with this response.
n. Excel file provided electronically with this response.
o. Excel file provided electronically with this response.
p. Excel file provided electronically with this response.
q. Excel file provided electronically with this response.
r. Schedule Q-7 Proof of Revenue.xlsx filed with the RFP native files.
s. H-1 (Summary of Test Year Production O&M).xlsx provided electronically with this response.
t. Excel file provided electronically with this response.
u. Excel file provided electronically with this response.
v. Excel file provided electronically with this response.
w. Excel file provided electronically with this response.
x. Excel file provided electronically with this response.
y. Excel file provided electronically with this response.
z. SWEPCO Misc Rev TYE Mar 2020.xlsx filed with the RFP native files.
aa. Excel file provided electronically with this response.
bb. Excel file provided electronically with this response.
cc. SWEPCO TX COS_Class TY 3_2020.xlsx. filed as Schedule P-1 with the RFP native files.

dd. Excel file provided electronically with this response.
ee. Excel file provided electronically with this response.
ff. Excel file provided electronically with this response.
gg. Excel file provided electronically with this response.
hh. Excel file provided electronically with this response.
ii. Excel file provided electronically with this response.
jj. Excel file provided electronically with this response.
kk. Excel file provided electronically with this response.
ll. Excel file provided electronically with this response.
mm. Excel file provided electronically with this response.
nn. Excel file provided as Highly Sensitive (duplicate file).

Certain attachments responsive to this request are HIGHLY SENSITIVE MATERIAL under the terms of the Protective Order. Due to current restrictions associated with COVID-19, this information is being provided electronically and a secure login to access the information will be provided upon request to individuals who have signed the Protective Order Certification.

Prepared By: Earlyne T. Reynolds	Title: Reg Pricing & Analysis Mgr
Prepared By: Reid Newman	Title: Economic Forecast Analyst Staff
Prepared By: Tiffany A. Powell Day	Title: Regulatory Acctg Case Mgr
Prepared By: Tara D. Beske	Title: Regulatory Consultant Staff

Sponsored By: Michael A. Baird	Title: Mng Dir Acctng Policy & Rsrch
Sponsored By: John O. Aaron	Title: Dir Reg. Pricing & Analysis
Sponsored By: Jennifer Jackson	Title: Reg Pricing & Analysis Mgr.
Sponsored By: Chad M. Burnett	Title: Dir Economic Forecasting
Sponsored By: David A. Hodgson	Title: Tax Acctg & Reg Support Mgr.
Sponsored By: Monte A. McMahon	Title: VP Generating Assets SWEPCO

SWEPCO Native Load	TE CPT	SWE - Billing Net	SWE - Company Net	AR - Company Net	LA - Company Net	TX - Company Net	Valley Net	EASTEX Self Supplied Load Net	Rayburn
	6/21/2019 1:00	2409.559	2333.559	472.213	874.715	986.631	-77	153	
	6/21/2019 2:00	2303.151	2223.151	444.963	829.258	948.93	-76	156	
	6/21/2019 3:00	2237.56	2154.56	433.395	798.181	922.984	-70	153	
	6/21/2019 4:00	2201.894	2115.894	431.165	779.794	904.935	-69	155	
	6/21/2019 5:00	2179.676	2089.676	431.877	763.231	894.568	-64	154	
	6/21/2019 6:00	2227.622	2139.622	447.152	770.066	922.404	-67	155	
	6/21/2019 7:00	2311.608	2224.608	473.888	781.616	969.103	-69	156	
	6/21/2019 8:00	2401.542	2317.542	500.24	808.315	1008.988	-70	154	
	6/21/2019 9:00	2540.1	2452.1	534.033	855.6	1062.467	-69	157	
	6/21/2019 10:00	2697.154	2623.154	578.007	919.771	1125.376	-81	155	
	6/21/2019 11:00	2850.545	2789.545	608.373	991.314	1189.858	-93	154	
	6/21/2019 12:00	3026.398	2975.398	635.739	1065.998	1273.661	-103	154	
	6/21/2019 13:00	3185.791	3140.791	674.355	1136.715	1329.721	-111	156	
	6/21/2019 14:00	3328.686	3289.686	700.45	1197.078	1392.157	-117	156	
	6/21/2019 15:00	3442.358	3414.358	703.744	1247.8	1462.814	-126	154	
	6/21/2019 16:00	3482.99	3452.99	720.69	1271.352	1460.949	-125	155	
	6/21/2019 17:00	3467.337	3431.337	715.211	1270.046	1446.079	-119	155	-105
	6/21/2019 18:00	3425.614	3390.614	705.942	1267.37	1417.302	-119	154	
	6/21/2019 19:00	3328.312	3296.312	677.068	1229.181	1390.063	-122	154	
	6/21/2019 20:00	3198.397	3155.397	655.302	1178.65	1321.445	-111	154	
	6/21/2019 21:00	3053.203	3006.203	618.78	1123.127	1264.296	-107	154	
	6/21/2019 22:00	2967.25	2917.25	598.975	1089.409	1228.866	-103	153	
	6/21/2019 23:00	2799.757	2742.757	565.862	1014.014	1162.881	-97	154	
	6/22/2019 0:00	2635.631	2564.631	529.406	942.384	1092.841	-85	156	
	6/22/2019 1:00	2425.22	2354.22	485.74	879.504	988.977	-79	150	
	6/22/2019 2:00	2329.025	2254.025	460.617	834.6	958.808	-77	152	
	6/22/2019 3:00	2235.036	2156.036	441.665	797.66	916.711	-72	151	
	6/22/2019 4:00	2195.447	2114.447	428.006	785.434	901.008	-70	151	
	6/22/2019 5:00	2163.59	2083.59	418.268	776.079	889.244	-71	151	
	6/22/2019 6:00	2181.132	2097.132	426.505	778.566	892.061	-69	153	
	6/22/2019 7:00	2161.31	2077.31	424.89	759.692	892.728	-67	151	
	6/22/2019 8:00	2258.891	2179.891	437.853	785.35	956.688	-73	152	
	6/22/2019 9:00	2401.42	2326.42	459.349	853.441	1013.63	-76	151	
	6/22/2019 10:00	2606.16	2540.16	490.894	936.675	1112.592	-87	153	
	6/22/2019 11:00	2783.322	2726.322	525.697	1024.368	1176.257	-98	155	
	6/22/2019 12:00	2927.146	2874.146	550.626	1087.137	1236.384	-104	157	
	6/22/2019 13:00	3061.505	3019.505	579.848	1150.619	1289.038	-113	155	
	6/22/2019 14:00	3149.996	3110.996	595.822	1191.028	1324.146	-118	157	
	6/22/2019 15:00	3179.882	3146.882	611.399	1218.706	1316.777	-123	156	
	6/22/2019 16:00	3196.944	3164.944	613.618	1233.093	1318.233	-124	156	
	6/22/2019 17:00	3194.091	3167.091	611.632	1246.617	1308.842	-127	154	
	6/22/2019 18:00	3134.093	3100.093	579.332	1229.006	1291.755	-122	156	
	6/22/2019 19:00	3018.902	2981.902	539.478	1203.406	1239.018	-120	157	
	6/22/2019 20:00	2922.013	2883.013	516.453	1155.731	1210.828	-116	155	
	6/22/2019 21:00	2826.53	2780.53	487.209	1113.271	1180.05	-110	156	
	6/22/2019 22:00	2761.5	2712.5	469.55	1085.812	1157.138	-105	154	

SWEPCO Native Load	TE CPT	SWE - Billing Net	SWE - Company Net	AR - Company Net	LA - Company Net	TX - Company Net	Valley Net	EASTEX Self Supplied Load Net	Rayburn
	7/17/2019 0:00	2615.818	2553.818	501.512	976.647	1075.659	-91	153	
	7/17/2019 1:00	2466.074	2393.074	472.823	907.067	1013.184	-80	153	
	7/17/2019 2:00	2344.843	2269.843	443.327	855.023	971.493	-77	152	
	7/17/2019 3:00	2266.71	2186.71	430.578	819.244	936.889	-73	153	
	7/17/2019 4:00	2203.24	2118.24	425.183	786.049	907.009	-70	155	
	7/17/2019 5:00	2193.077	2113.077	429.558	780.643	902.876	-72	152	
	7/17/2019 6:00	2230.896	2149.896	441.693	791.252	916.951	-74	155	
	7/17/2019 7:00	2326.533	2241.533	460.991	806.192	974.351	-69	154	
	7/17/2019 8:00	2446.676	2366.676	517.849	826.326	1022.501	-74	154	
	7/17/2019 9:00	2565.766	2486.766	549.603	866.717	1070.447	-75	154	
	7/17/2019 10:00	2755.625	2687.625	595.456	930.728	1161.441	-86	154	
	7/17/2019 11:00	2952.158	2894.158	637.735	1009.334	1247.09	-95	153	
	7/17/2019 12:00	3133.467	3081.467	679.891	1094.593	1306.983	-100	152	
	7/17/2019 13:00	3274.365	3242.365	711.807	1173.038	1357.52	-119	151	
	7/17/2019 14:00	3426.902	3390.902	737.462	1225.892	1427.548	-115	151	
	7/17/2019 15:00	3504.006	3478.006	742.412	1276.18	1459.414	-125	151	
	7/17/2019 16:00	3545.607	3524.607	752.442	1299.44	1472.725	-128	149	
	7/17/2019 17:00	3558.749	3544.749	762.393	1310.029	1472.327	-136	150	-102
	7/17/2019 18:00	3477.288	3460.288	739.858	1302.734	1417.696	-135	152	
	7/17/2019 19:00	3416.334	3396.334	717.124	1276.67	1402.54	-130	150	
	7/17/2019 20:00	3284.761	3259.761	696.527	1229.4	1333.834	-125	150	
	7/17/2019 21:00	3133.87	3102.87	660.527	1169.828	1272.515	-119	150	
	7/17/2019 22:00	2991.622	2954.622	620.379	1119.525	1214.718	-114	151	
	7/17/2019 23:00	2807.505	2758.505	585.609	1045.124	1127.772	-103	152	
	7/18/2019 0:00	2598.962	2537.962	527.867	964.771	1045.323	-89	150	
	7/18/2019 1:00	2477.788	2411.788	496.776	911.954	1003.059	-84	150	
	7/18/2019 2:00	2367.636	2295.636	467.079	864.691	963.866	-77	149	
	7/18/2019 3:00	2279.496	2203.496	447.978	830.234	925.284	-74	150	
	7/18/2019 4:00	2242.089	2162.089	445.952	803.613	912.524	-69	149	
	7/18/2019 5:00	2226.694	2147.694	439.075	790.435	918.183	-71	150	

SWEPCO Native Load	TE CPT	SWE - Billing Net	SWE - Company Net	AR - Company Net	LA - Company Net	TX - Company Net	Valley Net	EASTEX Self Supplied Load Net	Rayburn
	8/12/2019 0:00	2637.772	2569.772	514.079	1005.168	1050.525	-90	158	
	8/12/2019 1:00	2488.764	2415.764	480.776	938.892	996.095	-84	157	
	8/12/2019 2:00	2377.073	2298.073	459.861	890.474	947.738	-78	157	
	8/12/2019 3:00	2291.765	2211.765	438.488	856.332	916.945	-75	155	
	8/12/2019 4:00	2242.642	2158.642	429.319	827.751	901.572	-73	157	
	8/12/2019 5:00	2222.523	2134.523	418.475	816.223	899.826	-70	158	
	8/12/2019 6:00	2292.521	2210.521	436.482	834.69	939.349	-74	156	
	8/12/2019 7:00	2400.622	2319.622	476.665	859.706	983.252	-76	157	
	8/12/2019 8:00	2477.596	2393.596	500.253	860.13	1033.212	-73	157	
	8/12/2019 9:00	2660.782	2590.782	558.176	931.897	1100.709	-79	149	
	8/12/2019 10:00	2885.547	2824.547	601.081	1020.774	1202.692	-89	150	
	8/12/2019 11:00	3097.745	3053.745	650.488	1115.123	1288.134	-100	144	
	8/12/2019 12:00	3346.306	3307.306	713.268	1208.771	1385.266	-111	150	
	8/12/2019 13:00	3479.665	3450.665	734.29	1288.728	1427.648	-121	150	
	8/12/2019 14:00	3680.671	3663.671	766.976	1347.326	1549.368	-132	149	
	8/12/2019 15:00	3736.681	3723.681	777.825	1383.064	1562.792	-134	147	
	8/12/2019 16:00	3774.163	3767.163	790.531	1415.018	1561.614	-141	148	-110
	8/12/2019 17:00	3766.785	3759.785	799.423	1422.355	1538.007	-142	149	
	8/12/2019 18:00	3678.084	3673.084	776.557	1406.879	1489.648	-147	152	
	8/12/2019 19:00	3584.654	3571.654	765.708	1352.427	1453.519	-140	153	
	8/12/2019 20:00	3448.36	3430.36	736.461	1312.515	1381.384	-136	154	
	8/12/2019 21:00	3342.462	3315.462	701.927	1277.777	1335.757	-128	155	
	8/12/2019 22:00	3171.501	3136.501	667.193	1207.696	1261.612	-121	156	
	8/12/2019 23:00	2922.101	2872.101	612.671	1099.5	1159.93	-106	156	
	8/13/2019 0:00	2709.403	2650.403	558.576	1016.463	1075.363	-96	155	
	8/13/2019 1:00	2551.952	2486.952	521.425	946.175	1019.351	-90	155	
	8/13/2019 2:00	2426.397	2354.397	494.105	887.541	972.751	-83	155	
	8/13/2019 3:00	2356.806	2281.806	472.588	863.037	946.181	-81	156	

SWEPCO Native Load	TE CPT	SWE - Billing Net	SWE - Company Net	AR - Company Net	LA - Company Net	TX - Company Net	Valley Net	EASTEX Self Supplied Load Net
	9/6/2019 0:00	2448.613	2386.613	495.389	879.519	1011.705	-78	140
	9/6/2019 1:00	2326.214	2261.213	472.285	831.507	957.421	-74	139
	9/6/2019 2:00	2210.309	2141.307	440.859	785.116	915.332	-71	140
	9/6/2019 3:00	2141.793	2065.792	426.547	748.146	891.099	-62	138
	9/6/2019 4:00	2076.938	2000.938	402.735	726.015	872.188	-63	139
	9/6/2019 5:00	2075.105	1996.105	408.136	714.708	873.261	-59	138
	9/6/2019 6:00	2113.259	2036.26	422.692	736.397	877.171	-62	139
	9/6/2019 7:00	2228.805	2154.805	449.185	773.364	932.256	-65	139
	9/6/2019 8:00	2262.364	2185.365	472.763	769.185	943.417	-63	140
	9/6/2019 9:00	2422.38	2355.379	516.502	818.528	1020.348	-70	137
	9/6/2019 10:00	2630.292	2570.292	550.869	897.078	1122.345	-76	136
	9/6/2019 11:00	2872.683	2823.683	600.15	1003.327	1220.206	-87	136
	9/6/2019 12:00	3144.475	3111.475	648.06	1122.304	1341.11	-103	136
	9/6/2019 13:00	3331.387	3310.387	678.829	1217.747	1413.811	-116	137
	9/6/2019 14:00	3481.319	3466.319	715.267	1290.002	1461.05	-126	141
	9/6/2019 15:00	3584.271	3571.27	741.567	1333.747	1495.956	-132	145
	9/6/2019 16:00	3607.161	3599.16	738.992	1364.391	1495.777	-136	144
	9/6/2019 17:00	3584.449	3578.449	724.392	1366.211	1487.846	-137	143
	9/6/2019 18:00	3514.631	3509.631	710.438	1353.512	1445.681	-139	144
	9/6/2019 19:00	3369.436	3356.436	690.846	1288.25	1377.34	-131	144
	9/6/2019 20:00	3178.122	3149.122	655.433	1205.263	1288.426	-115	144
	9/6/2019 21:00	3054.081	3024.082	628.173	1150.302	1245.607	-115	145
	9/6/2019 22:00	2853.294	2811.294	580.765	1070.726	1159.803	-101	143
	9/6/2019 23:00	2662.59	2609.59	542.083	975.052	1092.454	-90	143
	9/7/2019 0:00	2477.053	2416.054	488.272	907.715	1020.066	-83	144
	9/7/2019 1:00	2353.036	2286.036	471.963	842.807	971.266	-76	143
	9/7/2019 2:00	2236.256	2159.256	444.867	793.243	921.145	-66	143
	9/7/2019 3:00	2141.029	2061.029	427.365	751.492	882.172	-64	144
	9/7/2019 4:00	2082.644	2000.643	413.315	730.119	857.21	-62	144
	9/7/2019 5:00	2041.753	1953.752	405.35	707.923	840.479	-56	144
	9/7/2019 6:00	2018.381	1934.381	397.168	706.759	830.455	-58	142
	9/7/2019 7:00	2037.18	1950.179	407.168	708.426	834.586	-58	145
	9/7/2019 8:00	2064.528	1974.527	402.36	711.482	860.685	-54	144
	9/7/2019 9:00	2220.273	2140.273	445.981	777.84	916.452	-65	145
	9/7/2019 10:00	2435.746	2368.745	487.329	875.053	1006.363	-79	146

SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' ELEVENTH SET OF REQUESTS FOR INFORMATION

Question No. TIEC 11-4:

Please identify all Texas retail customers by customer class that utilize behind-themeter generation to serve all or a portion of the customers' loads.

Response No. TIEC 11-4:

Please see TIEC 11-4 Attachment 1.

Prepared By: Christopher N. Martel Title: Regulatory Consultant Sr

Sponsored By: Drew W. Seidel Title: VP Dist Region Opers

Sponsored By: Paul E. Pratt Title: Dir Customer Svcs & Mktg

Class	Service Voltage Level	Service Type	Total Generation Capacity kW (AC)	Generator A Technology	Generator A Fuel	Generator A Type
IPP	T	Purchase Power	440,000.0	Internal combustion	Natural gas	Synchronous
Ind	T	Cogen	83,700.0	Steam turbine	Wood waste	Synchronous
Ind	D	Purchase Power	5,000.0	Steam turbine	Wood waste	Synchronous
Ind	D		372.0	Photovoltaic	Solar	Inverter
Com	D	Cogen - Option 2	72.0	Photovoltaic	Solar	Inverter
Com	D	Cogen - Option 2	60.0	Internal combustion	Waste gas	Inverter
Com	D	Cogen - Option 2	42.0	Photovoltaic	Solar	Inverter
Com	D	Cogen - Option 2	38.0	Photovoltaic	Solar	Inverter
Com	D	Cogen - Option 2	36.0	Photovoltaic	Solar	Inverter
Com	D	Cogen - Option 2	34.0	Photovoltaic	Solar	Inverter
Com	D	Cogen - Option 2	22.8	Photovoltaic	Solar	Inverter
Com	D	Cogen - Option 2	22.0	Photovoltaic	Solar	Inverter
Com	D	Cogen - Option 2	21.6	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	20.0	Photovoltaic	Solar	Inverter
Res	D		19.2	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	19.0	Photovoltaic	Solar	Inverter
Res	D	Net Metering	19.0	Photovoltaic	Solar	Inverter
Res	D	Net Metering	18.5	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	18.0	Photovoltaic	Solar	Induction
Res	D	Cogen - Option 2	18.0	Photovoltaic	Solar	Inverter
Res	D		16.6	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	15.4	Photovoltaic	Solar	Inverter

Class	Service Voltage Level	Service Type	Total Generation Capacity kW (AC)	Generator A Technology	Generator A Fuel	Generator A Type
Res	D		15.0	Photovoltaic	Solar	Inverter
Res	D		14.4	Photovoltaic	Solar	Inverter
Com	D	Cogen - Option 2	14.1	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	14.0	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	14.0	Photovoltaic	Solar	Inverter
Res	D	Net Metering	13.4		Solar	Inverter
Res	D		13.3	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	13.0	Photovoltaic	Solar	Inverter
Res	D		12.8	Photovoltaic	Solar	Inverter
Res	D	Net Metering	12.7	Photovoltaic	Solar	Inverter
Res	D	Net Metering	12.7	Photovoltaic	Solar	Inverter
Res	D		12.5	Photovoltaic	Solar	Inverter
Com	D	Cogen - Option 2	12.2	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	12.0	Photovoltaic	Solar	Inverter
Res	D	Net Metering	12.0	Photovoltaic	Solar	
Com	D	Cogen - Option 2	12.0	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	12.0	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	12.0	Photovoltaic	Solar	Inverter
Res	D	Net Metering	12.0	Photovoltaic	Solar	Inverter
Res	D	Net Metering	12.0	Photovoltaic	Solar	Inverter
Com	D	Cogen - Option 2	12.0	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	12.0	Photovoltaic	Solar	Inverter
Res	D	Net Metering	11.4	Photovoltaic		Inverter
Res	D	Cogen - Option 2	11.4	Photovoltaic	Solar	Inverter
Res	D		11.4	Photovoltaic	Solar	Inverter
Res	D		11.4	Photovoltaic	Solar	Inverter
Res	D		11.4	Photovoltaic	Solar	Inverter

Class	Service Voltage Level	Service Type	Total Generation Capacity kW (AC)	Generator A Technology	Generator A Fuel	Generator A Type
Res	D		11.0	Photovoltaic	Solar	Inverter
Res	D	Net Metering	11.0	Photovoltaic	Solar	Inverter
Com	D	Cogen - Option 2	11.0	Photovoltaic	Solar	Inverter
Res	D	Net Metering	11.0	Micro turbine	Solar	Inverter
Res	D	Net Metering	10.7	Photovoltaic	Solar	Inverter
Res	D	Net Metering	10.7	Photovoltaic	Solar	Inverter
Res	D	Net Metering	10.7	Photovoltaic	Solar	Inverter
Res	D		10.6	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	10.5	Photovoltaic	Solar	Inverter
Res	D		10.3	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	10.2	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	10.0	Photovoltaic	Solar	Inverter
Res	D	Net Metering	10.0	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	10.0	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	10.0	Photovoltaic	Solar	Inverter
Res	D	Net Metering	10.0	Photovoltaic	Solar	Inverter
Res	D	Net Metering	10.0	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	10.0	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	10.0	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	10.0	Wind turbine	Wind	Inverter
Res	D	Cogen - Option 2	10.0	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	10.0	Photovoltaic	Solar	Inverter
Res	D		10.0	Photovoltaic	Solar	Inverter
Com	D	Cogen - Option 2	9.6	Photovoltaic	Solar	Inverter
Res	D	Net Metering	9.5	Photovoltaic	Solar	Inverter
Res	D		9.5	Photovoltaic	Solar	Inverter

Class	Service Voltage Level	Service Type	Total Generation Capacity kW (AC)	Generator A Technology	Generator A Fuel	Generator A Type
Res	D	Cogen - Option 2	9.4	Photovoltaic	Solar	Inverter
Res	D	Net Metering	9.2	Photovoltaic	Solar	Inverter
Res	D		8.8	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	8.7	Photovoltaic	Solar	Inverter
Res	D		8.7	Photovoltaic	Solar	Inverter
Res	D	Net Metering	8.6	Photovoltaic	Solar	Inverter
Res	D		8.4	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	8.2	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	8.2	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	8.2	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	8.1	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	8.0	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	7.9	Photovoltaic	Solar	Inverter
Res	D		7.8	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	7.7	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	7.7	Photovoltaic	Solar	Inverter
Res	D	Net Metering	7.7	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	7.7	Photovoltaic	Solar	Inverter
Res	D		7.7	Photovoltaic	Solar	Inverter
Res	D		7.7	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	7.6	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	7.6	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	7.6	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	7.6	Photovoltaic	Solar	Inverter

Class	Service Voltage Level	Service Type	Total Generation Capacity kW (AC)	Generator A Technology	Generator A Fuel	Generator A Type
Res	D	Net Metering	7.6	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	7.6	Photovoltaic	Solar	Inverter
Res	D		7.6	Photovoltaic	Solar	Inverter
Res	D		7.6	Photovoltaic	Solar	Inverter
Res	D		7.6	Photovoltaic	Solar	Inverter
Res	D		7.6	Photovoltaic	Solar	Inverter
Res	D		7.5	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	7.5	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	7.3	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	7.3	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	7.1	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	7.1	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	7.0	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	7.0	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	7.0	Photovoltaic	Solar	Inverter
Res	D		7.0	Photovoltaic	Solar	Inverter
Res	D	Net Metering	6.8	Photovoltaic	Solar	Inverter
Res	D		6.7	Photovoltaic	Solar	Inverter
Res	D	Net Metering	6.5	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	6.5	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	6.5	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	6.4	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	6.3	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	6.2	Photovoltaic	Solar	Inverter

Class	Service Voltage Level	Service Type	Total Generation Capacity kW (AC)	Generator A Technology	Generator A Fuel	Generator A Type
Res	D	Cogen - Option 2	6.2	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	6.0	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	6.0	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	6.0	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	6.0	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	6.0	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	6.0	Photovoltaic	Solar	Inverter
Com	D	Cogen - Option 2	6.0	Photovoltaic	Solar	Inverter
Com	D	Cogen - Option 2	6.0	Photovoltaic	Solar	Inverter
Res	D		6.0	Photovoltaic	Solar	Inverter
Res	D		6.0	Photovoltaic	Solar	Inverter
Res	D		5.8	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	5.4	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	5.4	Photovoltaic	Solar	Inverter
Res	D	Net Metering	5.4	Photovoltaic	Solar	Inverter
Res	D		5.2	Photovoltaic	Solar	Inverter
Res	D		5.2	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	5.2	Photovoltaic	Solar	Inverter
Res	D		5.2	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	5.0	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	5.0	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	5.0	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	5.0	Photovoltaic	Solar	Inverter

Class	Service Voltage Level	Service Type	Total Generation Capacity kW (AC)	Generator A Technology	Generator A Fuel	Generator A Type
Res	D	Cogen - Option 2	5.0	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	5.0	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	5.0	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	5.0	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	5.0	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	5.0	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	5.0	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	5.0	Photovoltaic	Solar	Inverter
Res	D	Net Metering	5.0	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	5.0	Photovoltaic	Solar	Inverter
Res	D	Net Metering	5.0	Photovoltaic	Solar	Inverter
Res	D		5.0	Photovoltaic	Solar	Inverter
Res	D		5.0	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	4.8	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	4.8	Photovoltaic	Solar	Inverter
Res	D		4.1	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	4.0	Photovoltaic	Solar	Inverter
Com	D	Cogen - Option 2	4.0	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	4.0	Photovoltaic	Solar	Inverter
Com	D	Cogen - Option 2	4.0	Photovoltaic	Solar	Inverter
Res	D	Net Metering	4.0	Photovoltaic	Solar	
Res	D	Cogen - Option 2	4.0	Photovoltaic	Solar	Inverter

Class	Service Voltage Level	Service Type	Total Generation Capacity kW (AC)	Generator A Technology	Generator A Fuel	Generator A Type
Com	D	Cogen - Option 2	4.0	Photovoltaic	Solar	Inverter
Res	D	Net Metering	4.0	Photovoltaic	Solar	Inverter
Res	D		3.8	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	3.6	Photovoltaic	Solar	Inverter
Res	D		3.6	Photovoltaic	Solar	Inverter
Res	D		3.5	Photovoltaic	Solar	Inverter
Com	D	Cogen - Option 2	3.0	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	3.0	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	3.0	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	3.0	Photovoltaic	Solar	Inverter
Res	D		2.9	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	2.4	Photovoltaic	Solar	Inverter
Res	D		2.3	Photovoltaic	Solar	Inverter
Res	D		2.3	Photovoltaic	Solar	Inverter
Com	D	Cogen - Option 2	2.0	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	1.5	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	1.5	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	1.5	Photovoltaic	Solar	Inverter
Res	D	Cogen - Option 2	1.1	Photovoltaic	Solar	Inverter

SOUTHWESTERN ELECTRIC POWER COMPANY

Texas Revenue Distribution

CUSTOMER GROUP	RATE CODE	VOLTAGE LEVEL	TEST YEAR ADJ KWH	PRESENT RATE SCHEDULE REVENUE	PRESENT OPERATING INCOME	RATE BASE	PRESENT RATE OF RETURN	PRESENT RELATIVE RATE OF RETURN	EQUALIZED BASE REVENUE CHANGE	EQUALIZED BASE PERCENT CHANGE	TARGET BASE REVENUE CHANGE	TARGET BASE PERCENT CHANGE	PROPOSED BASE REVENUE CHANGE	RATE DESIGN DIFF FROM TARGET	PROPOSED BASE PERCENT CHANGE
RESIDENTIAL	12,15,16,19,61	SEC	2,165,609,056	147,077,995	28,602,462	832,966,681	3 43%	1.06	41,074,656	27 93%	41,074,656	27 93%	41,074,177	(479)	27 93%
GENERAL SERVICE W/DEM	200,205,207,210-215,224,281	SEC	205,598,031	16,998,369	3,748,840	93,260,889	4 02%	1.24	3,886,913	22 87%	5,605,870	32 98%	5,101,574	(504 296)	30 01%
GENERAL SERVICE WO/DEM	202,208,218	SEC	66,333,658	5,669,225	730,637	34,009,683	2 15%	0.66	2,247,226	39 64%	1,869,646	32 98%	2,374,147	504,500	41 88%
LIGHTING & POWER	60,63,240,243,291	SEC	2,161,933,051	100,037,248	16,488,045	614,875,723	2 68%	0 83	36,349,498	36 34%	32,991,155	32 98%	32,990,727	(428)	32 98%
LIGHTING & POWER	66,246,249,251,252,254,277	PRI	667,056,010	23,827,679	5,891,549	123,849,861	4 76%	1 47	3,971,269	16 67%	7,858,099	32 98%	7,857,800	(299)	32 98%
COTTON GIN	253	SEC	5,234,123	265,617	(34,215)	2,119,792	-1 61%	(0 50)	244,080	91 89%	87,597	32 98%	87,598	1	32 98%
TOTAL COMMERCIAL			3,106,154,872	146,798,138	26,824,856	868,115,948	3 09%	0 95	46,698,987	31 81%	48,412,368	32 98%	48,411,846	(523)	32 98%
LARGE LIGHTING & POWER	351	PRI	164,644,585	5,298,104	1,035,317	31,255,013	3 31%	1.02	1,590,320	30 02%	1,747,255	32 98%	1,747,318	63	32 98%
LARGE LIGHTING & POWER	342,344	TRAN	818,720,986	22,387,847	4,226,052	155,899,244	2 71%	0 84	9,147,516	40 86%	7,383,259	32 98%	7,383,336	77	32 98%
METAL MELTING - SEC	335	SEC	1,983,769	143,749	17,272	804,615	2 15%	0 66	53,205	37 01%	47,407	32 98%	47,402	(5)	32 98%
METAL MELTING - PRI	325	PRI	37,667,206	1,402,858	174,016	8,006,774	2 17%	0 67	526,501	37 53%	462,647	32 98%	462,652	5	32 98%
METAL MELTING - TRANS	318,321	69 TRAN	53,731,559	1,498,929	424,148	6,743,741	6 29%	1 94	81,464	5 43%	494,330	32 98%	494,289	(41)	32.98%
OILFIELD PRIMARY	330	PRI	384,472,605	10,636,387	1,762,777	63,152,705	2 79%	0 86	3,643,272	34 25%	3,507,760	32 98%	3,507,691	(69)	32 98%
OILFIELD SECONDARY	331	SEC	20,704,032	588,848	(24,972)	5,053,862	-0 49%	(0 15)	507,957	86 26%	194,196	32 98%	194,214	19	32 98%
TOTAL INDUSTRIAL			1,481,924,742	41,956,723	7,614,611	270,915,954	2 81%	0 87	15,550,235	37 06%	13,836,853	32 98%	13,836,902	48	32 98%
TOTAL COMMERCIAL & INDUSTRIAL			4,588,079,614	188,754,861	34,439,467	1,139,031,902	3 02%	0 93	62,249,222	32 98%	62,249,222	32 98%	62,248,747	(474)	32 98%
MUNICIPAL PUMPING	541,543,550,553	SEC	60,026,735	2,279,333	527,394	11,569,484	4 56%	1 41	401,037	17 59%	307,396	13 49%	307,379	(17)	13 49%
MUNICIPAL SERVICE	544,548	SEC	26,943,781	1,650,219	522,720	6,950,240	7 52%	2 32	(27,445)	-1 66%	222,552	13 49%	222,558	6	13 49%
TOTAL MUNICIPAL PUMPING & SERVICE			86,970,515	3,929,551	1,050,113	18,519,724	5 67%	1 75	373,592	9 51%	529,948	13 49%	529,937	(11)	13 49%
MUNICIPAL LIGHTING	521,528,529,535, 538	SEC	26,004,489	2,267,085	557,855	11,951,475	4 67%	1 44	397,616	17 54%	305,744	13 49%	305,627	(117)	13 48%
PUBLIC STREET & HWY	534,539,739	SEC	1,070,584	30,170	(21,163)	435,374	-4 86%	(1 50)	68,554	227 23%	4,069	13 49%	4,077	8	13 51%
TOTAL MUNICIPAL LIGHTING			27,075,073	2,297,255	536,692	12,386,848	4 33%	1 34	466,170	20 29%	309,813	13 49%	309,704	(109)	13 48%
TOTAL MUNICIPAL & MUNICIPAL LIGHTING		SEC	114,045,588	6,226,806	1,586,806	30,906,572	5 13%	1 58	839,761	13 49%	839,761		839,641	(121)	13.48%
PRIVATE, OUTDOOR, AREA	90-143	SEC	49,398,122	4,150,616	937,573	20,975,925	4 47%	1 38	751,957	18 12%	751,957	18 12%	752,003	46	18 12%
CUST-OWNED LIGHTING	203,204,532	SEC	6,704,408	293,022	35,064	1,661,640	2 11%	0 65	110,641	37 76%	110,641	37 76%	110,640	(1)	37 76%
TOTAL LIGHTING			56,102,530	4,443,639	972,637	22,637,565	4 30%	1 33	862,598	19 41%	862,598	19 41%	862,643	45	19 41%
TOTAL FIRM RETAIL			6,923,836,788	346,503,301	65,601,371	2,025,542,720	3 24%	1.00	105,026,238	30 31%	105,026,238	30 31%	105,025,209	(1 029)	30 31%

EXECUTIVE SUMMARY OF JENNIFER L. JACKSON

Jennifer L. Jackson is a Regulated Pricing and Analysis, Manager, in Regulated Pricing and Analysis, part of the American Electric Power Service Corporation (AEPSC) Regulatory Services Department. As a Regulated Pricing & Analysis Manager, Ms. Jackson's job duties include providing testimony, rate review analysis and support, pricing design, implementation of pricing programs, and regulatory compliance for the AEP operating companies.

Southwestern Electric Power Company's (SWEPCO or the Company) rate design proposal for its Texas jurisdiction consists of revised rates in its tariffs based on the proposed revenue distribution and any other language revisions to rate schedules and riders.

Ms. Jackson testifies that SWEPCO's goal for its proposed rate design is twofold. The first goal of the proposed rate design is to design rates that achieve the overall proposed revenue change based on the filed class cost-of-service study. The second goal of the proposed rate design is to develop rates that move all major classes of customers closer to an equalized return, meaning the proposed rates for each customer class are designed to recover the class responsibility for the cost to serve each respective major rate class. As explained by Ms. Jackson, these goals have been balanced with considerations such as overall customer impact and moderation of severe customer impact.

The overall level of non-fuel rate increase being requested by SWEPCO in this filing for its Texas retail jurisdiction is approximately $105 million, or a 30.31% increase over Test Year[1] adjusted revenues, including the movement of Distribution Cost Recovery Factor (DCRF) and Transmission Cost Recovery Factor (TCRF) revenue requirements from rider

[1] The Test Year is the twelve-month period ending March 31, 2020.

recovery to base rate recovery. Including fuel revenues, the overall retail percentage change is 15.57%.

Ms. Jackson further explains that in this filing, SWEPCO is requesting a 7.22% return on rate base. Therefore, the equalized return from all classes will produce a revenue requirement necessary to achieve a return on rate base of 7.22%.

Ms. Jackson testifies that the revenue distribution is the rate design mechanism by which the revenue increase is assigned to the classes of customers. The revenue distribution also determines the revenue requirement targets for each class. In addition, Ms. Jackson sets out how the class revenue targets are determined, the results of the proposed revenue distribution, how the proposed rates revenue change is used in the design of rates, and how the final revenue change affects the relative rates of return for the classes.

Ms. Jackson also briefly describes each of the retail service rate schedules contained in SWEPCO's Texas Tariff and the changes to each. Ms. Jackson also notes that SWEPCO is proposing several changes to its Tariff Manual and provides a summary of the changes.

Overall, Ms. Jackson demonstrates that: (1) the base rate changes achieve the revenue required from each class according to the filed cost-of-service study and proposed revenue distribution; and (2) the proposed revenue distribution is reasonable and appropriately considers rate design factors such as class movement towards an equalized return and moderation of severe customer impacts.

to determine the revenue requirement needed to bring each class to what is called an equalized return. In other words, the revenue requirement at an equalized return is the amount of revenue needed from each class to recover the full costs of serving that customer class. In this filing, SWEPCO is requesting a 7.22% return on rate base. Therefore, the equalized return from all classes will produce a revenue requirement necessary to achieve a return on rate base of 7.22%. SWEPCO witness Mr. Aaron sponsors the jurisdiction and class cost-of-service study.

The equalized revenue requirement and revenue change based on that requirement is the starting place for the revenue distribution. However, other considerations must be examined before the final revenue change for each class can be determined. EXHIBIT JLJ-1, the proposed revenue distribution, details the development of the proposed class increases.

IV. REVENUE DISTRIBUTION

Q. PLEASE DESCRIBE WHAT THE REVENUE DISTRIBUTION ACCOMPLISHES.

A. The revenue distribution is the rate design mechanism by which the revenue increase is assigned to the classes of customers. The revenue distribution also determines the revenue requirement targets for each rate class. As discussed above, the filed cost-of-service study is the basis for the revenue distribution. However, factors other than the cost-of-service results have been taken into consideration and presented in the target base rate increases for each class.

The proposed revenue distribution shows the present rate schedule revenue by class along with each class's present rate of return, return relative to the retail total class return at the proposed return level (relative rate of return), equalized base increase, target base change in revenue, and total rate design proposed base change in revenue. The target base change in revenue determines the rate design revenue target for each class and is the basis for the class rate design. EXHIBIT JLJ-1 shows the components that make up the proposed revenue distribution.

Q. PLEASE DESCRIBE HOW THE CLASS REVENUE TARGETS REPRESENTED IN THE REVENUE DISTRIBUTION WERE DEVELOPED.

A. The cost-of-service study determines the equalized revenue requirement necessary for each class to achieve a retail class average return on rate base. As stated above, SWEPCO is requesting a return on rate base of 7.22%. Ideally, the cost-of-service study results would dictate the change to each class's revenue requirement. However, other considerations, such as moderation of customer impact and customer migration, are taken into account before the final class revenue change targets are determined.

Q. PLEASE DISCUSS THE MODERATION APPLIED TO THE EQUALIZED CLASS INCREASES.

A. The proposed system average base rate increase is 30.31%. Several classes show greater than system average increases at an equalized return and some classes show less than a system average increase. In order to mitigate the large increases and large impacts to certain classes, classes with similarly-situated customers were combined into a major rate class and the combined change in class revenue requirement at an equalized rate of return was applied to the individual classes. SWEPCO's Industrial class has several individual rate classes that serve one or very few customers. Having few customers in a rate class can make the class cost-of-service study results for a particular class susceptible to unusual outcomes that may impact the rate design in a particular test year. Grouping individual rate classes into major classes mitigates this situation. The major classes of customers used in the proposed revenue distribution include: Residential Commercial and Industrial, Municipal, and Lighting. SWEPCO is proposing to group the Commercial and Industrial customer classes into one large rate class to share the proposed increase among all the customers in the General Service, Lighting and Power, Large Lighting and Power, Metal Melting, Oilfield, and Cotton Gin rate classes and to facilitate sustainable migration among the customer classes within a family of rate options.

Q. WHAT ARE THE RESULTS OF THE PROPOSED REVENUE DISTRIBUTION?

A. The results of the proposed revenue distribution show that all the designated major classes of customers have either achieved an equalized return (a rate of return of 7.22% or a relative rate of return of 1.0) at the requested level of increase, or have made movement toward an equalized return. While the equalized return for each individual rate class is ideal, making the move to the equalized return all at the same time may lead to excessive impacts on certain groups of customers. The proposed revenue distribution appropriately considers both the equalized return and moderation. For example, the General Service, Lighting and Power, and Large Lighting and Power classes are combined with several specialty industrial rate classes including the Metal Melting rate class, the Oil Field Industrial rate class, and the Cotton Gin rate class to form the Commercial and Industrial major rate class. There are very few customers included in each of the industrial rate classes and combining them into a Commercial and Industrial major rate class provides stability and moderation in the individual customer impacts. The proposed revenue distribution for the combined Commercial and Industrial rate class indicates that a 32.98% increase is needed for the class as a whole to achieve an equalized rate of return at the major class level.

The revenue distribution also shows the total change including fuel and other rider revenues. The total bill change reflects the movement of Test Year DCRF and TCRF retail revenue requirements into base rates. The proposed DCRF and TCRF rates are set to $0.00 for all classes. The total bill change by rate class will vary by class depending on each class's kWh usage and fuel consumption. The revenue distribution shows the base rate and total bill change detail for all rate classes. The table below shows the major class base and total bill increase.

MAJOR RATE CLASS	BASE %	TOTAL %
RESIDENTIAL	27.93%	15.64%
COMMERCIAL	32.98%	16.82%
INDUSTRIAL	32.98%	13.28%
COMMERCIAL & INDUSTRIAL	32.98%	15.90%
MUNICIPAL	13.49%	5.84%
LIGHTING	19.41%	10.57%
TOTAL FIRM RETAIL	30.31%	15.57%

Q. HOW IS THE CLASS PROPOSED TARGET BASE REVENUE CHANGE AS SHOWN ON THE REVENUE DISTRIBUTION USED IN THE DESIGN OF THE PROPOSED RATES?

A. The proposed rate design for all classes is based on the target level of base rate change as shown in the revenue distribution. Each class's rate components, such as the customer charge, energy rate, demand rate, and minimum bill components, have been adjusted based on the target percent change as shown on the proposed revenue distribution. In most cases, where a class rate structure includes a demand and energy

SOUTHWESTERN ELECTRIC POWER COMPANY
TEXAS JURISDICTION
FOR TEST YEAR ENDED MARCH 31, 2020
TEST YEAR DATA BY RATE CLASS

		Number of Customers			kWh				
Class	Tariff Codes	Average	Unadj Year End	Adj Year End	Unadjusted	Customer	Weather	Proforma	Adjusted
Residential									
Residential	12,15,16,19,37	151,166	151,470	151,470	2,106,156,580	3,883,772	53,555,227	-	2,163,595,580
Residential DG	61	84	105	105	1,581,361	388,677	43,439	-	2,013,476
Total Residential		151,250	151,575	151,575	2,107,737,941	4,272,449	53,598,666	-	2,165,609,056
Commercial/Small Industrial									
Light & Power Sec	60,63,240,241,243	8,958	8,902	8,902	2,160,461,679	(13,824,040)	13,001,247	-	2,159,638,887
Light & Power Pri	66,246,249,251,252,254,277	160	158	158	675,244,846	(8,989,575)	800,739	-	667,056,010
General Service w/ Demand	200,205,207,210-215,224	10,543	10,624	10,624	202,389,173	1,552,885	1,541,476	-	205,483,534
General Service No Demand	202,208,218,219	11,398	11,393	11,393	65,793,310	(10,361)	550,708	-	66,333,658
Cotton Gin	253	7	8	8	4,565,380	668,743	-	-	5,234,123
General Service DG	281	5	5	5	114,497	-	-	-	114,497
Light & Power Sec DG	291	11	11	11	2,294,164	-	-	-	2,294,164
Total Commercial/Small Industrial		31,082	31,101	31,101	3,110,863,049	(20,602,348)	15,894,171	-	3,106,154,872
Large Industrial									
Metal Melting Service Trans	318,321	2	2	1	288,387,391	-	-	(234,655,832)	53,731,559
Metal Melting Service Dist Pri	325	7	6	6	42,656,544	(4,989,338)	-	-	37,667,206
Oilfield Pri	330	1,439	1,424	1,424	388,331,941	(3,859,336)	-	-	384,472,605
Oilfield Sec	331	21	33	34	1,841,963	718,069	-	18,144,000	20,704,032
Metal Melting Service Dist Sec	335	4	3	3	2,744,594	(760,825)	-	-	1,983,769
Large Light & Power Trans	342,344	5	5	6	800,286,203	-	-	18,434,783	818,720,986
Large Light & Power Pri	351	2	2	2	164,213,921	-	430,664	-	164,644,585
Total Large Industrial		1,480	1,475	1,476	1,688,462,557	(8,891,430)	430,664	(198,077,049)	1,481,924,742
Municipal									
Municipal Pumping	541,543,550,553	607	607	607	59,520,473	(16,082)	522,344	-	60,026,735
Municipal Service	544,548	1,494	1,494	1,494	26,711,785	(1,305)	233,301	-	26,943,781
Total Municipal		2,101	2,101	2,101	86,232,258	(17,387)	755,645	-	86,970,515
Lighting									
Outdoor Private & Area Lighting	90-143	34,780	34,792	34,792	49,349,701	48,421	-	-	49,398,122
Customer Owned Lighting	203,204,532	256	258	258	6,662,172	42,236	-	-	6,704,408
Municipal Public & Hwy Street Lighting	521,528,529,535,538	30,081	30,079	30,079	26,005,558	(1,069)	-	-	26,004,489
Public & Hwy Street Lighting	534,539,739	621	622	622	1,069,017	1,567	-	-	1,070,584
Total Lighting		65,738	65,751	65,751	83,086,448	91,154	-	-	83,177,602
Total SWEPCO Texas Firm Retail		186,168	186,510	186,511	7,076,382,253	(25,147,562)	70,679,146	(198,077,049)	6,923,836,788
Non-Firm									
Interruptible Power Service	320	3	3	-	72,744,000	-	-	(72,744,000)	-
Total Non-Firm		3	3	-	72,744,000	-	-	(72,744,000)	-
Total SWEPCO TEXAS RETAIL		**186,171**	**186,513**	**186,511**	**7,149,126,253**	**(25,147,562)**	**70,679,146**	**(270,821,049)**	**6,923,836,788**
Total SWEPCO AR Retail		121,579	121,992	121,992	3,694,411,453	(66,983,084)	21,141,253	(35,720,232)	3,612,849,390
Total SWEPCO LA Retail		231,165	231,290	231,289	6,438,650,297	32,366,730	11,240,944	(48,679,200)	6,433,578,771
Total SWEPCO Wholesale		7	6	6	2,285,491,301	(417,634,807)	49,847,537	-	1,917,704,031
Total SWEPCO		**538,922**	**539,801**	**539,798**	**19,567,679,304**	**(477,398,723)**	**152,908,879**	**(355,220,481)**	**18,887,968,979**

SOUTHWESTERN ELECTRIC POWER COMPANY
SCHEDULE Q-7

Present Rates

Rate Class: Large Light & Power Trans
Rate Codes: 342,344

Bill Component	Description	Rate	Billing Determinant	Revenue
kWh Charge	Per kWh	0.010382	818,720,986	$ 8,499,961
Block 2 kW Charge	Per kW	6.870000	1,433,918	$ 9,851,019
kVAR Charge	Per kVAR	0.510000	683,698	$ 348,686

Total Present Base Revenue	$ 21,803,555
Booked Adjusted Base Revenue	$ 22,387,847
Adjusted Fuel Revenue	$ 24,118,872
Ratio Base	97.39%
Book to Bill Factor	1.03

Proposed Rates

Rate Class: Large Light & Power Trans
Rate Codes: 342,344

Bill Component	Description	Rate	Billing Determinant	Revenue	
kWh Charge	Per kWh	0.012212	818,720,986	$ 9,998,221	3,960,000
Block 2 kW Charge	Per kW	7.930000	1,433,918	$ 11,370,973	
kVAR Charge	Per kVAR	0.660000	683,698	$ 451,241	
Synchronized Self Generation Load	per CP kW	$2.20	1,800,000	$ 3,960,000	

Total Proposed Base Revenue	$ 28,994,196
Proposed Adjusted Base Revenue	$ 29,771,184
Proposed Fuel Revenue	$ 24,118,872
$ Change Base	$ 7,383,336
% Change to Base Revenue	32.98%

SOUTHWESTERN ELECTRIC POWER COMPANY
SCHEDULE Q-7

Present Rates

Rate Class: Large Light & Power Pri
Rate Codes: 351

Bill Component	Description	Rate	Billing Determinant
kWh Charge	Per kWh	0.010382	164,644,585
Block 2 kW Charge	Per kW	10.020000	358,160
kVAR Charge	Per kVAR	0.510000	-

Total Present Base Revenue
Booked Adjusted Base Revenue
Adjusted Fuel Revenue
Ratio Base
Book to Bill Factor

Proposed Rates

Rate Class: Large Light & Power Pri
Rate Codes: 351

Bill Component	Description	Rate	Billing Determinant
kWh Charge	Per kWh	0.013816	164,644,585
Block 2 kW Charge	Per kW	13.320000	358,160
kVAR Charge	Per kVAR	0.660000	-

Total Proposed Base Revenue
Proposed Adjusted Base Revenue
Proposed Fuel Revenue
$ Change Base
% Change to Base Revenue

Revenue
$ 1,709,340
$ 3,588,764
$ -
$ 5,298,104
$ 5,298,104
$ 4,900,632
100.00%
1.00

Revenue
$ 2,274,730
$ 4,770,693
$ -
$ 7,045,422
$ 7,045,422
$ 4,900,632
$ 1,747,318
32.98%

SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO CITIES ADVOCATING REASONABLE DEREGULATION'S FIRST SET OF REQUESTS FOR INFORMATION

Question No. CARD 1-9:

Provide copies of all invoices for SWEPCO purchased power that included non-fuel or capacity charges that are included in the test year period purchased power charges.

Response No. CARD 1-9:

Please see CARD 1-9 CONFIDENTIAL Attachments 1-12 for the requested information. Please see CARD 1-9 Attachment 13 for the Renewable Energy Credit adjustment requested (provided electronically on the PUC Interchange).

The attachments responsive to this request are CONFIDENTIAL MATERIAL under the terms of the Protective Order. Due to current restrictions associated with COVID-19, this information is being provided electronically and a secure login to access the information will be provided upon request to individuals who have signed the Protective Order Certification.

Prepared By: Frances K. Bourland	Title: Regulatory Acctg Case Mgr
Sponsored By: Scott E. Mertz	Title: Regulatory Consultant Staff
Sponsored By: Michael A. Baird	Title: Mng Dir Acctng Policy & Rsrch

SOUTHWESTERN ELECTRIC POWER COMPANY
Replacement Energy Adjustment
For the test year ending 3/31/2020

Year	Period	Adjustment
2019	4	101,779.44
	5	83,488.94
	6	74,994.61
	7	85,349.70
	8	84,516.95
	9	110,280.36
	10	125,093.41
	11	105,469.22
	12	123,536.84
2020	1	132,901.86
	2	127,101.45
	3	126,788.69
		1,281,301.48

SOUTHWESTERN ELECTRIC POWER COMPANY
SCHEDULE Q-7

Present Rates

Rate Class: Large Light & Power Trans
Rate Codes: 342,344

Bill Component	Description	Rate	Billing Determinant		Revenue
kWh Charge	Per kWh	0.010382	818,720,986	$	8,499,961
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Rate Codes: 342,344

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Synchronized Self Generation Load	per CP kW	$2 20	1,800,000	$	3,960,000	

Total Proposed Base Revenue	$	28,994,196
Proposed Adjusted Base Revenue	$	29,771,184
Proposed Fuel Revenue	$	24,118,872
$ Change Base	$	7,383,336
% Change to Base Revenue		32.98%

SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' ELEVENTH SET OF REQUESTS FOR INFORMATION

Question No. TIEC 11-7:

Referring to the Proof of Revenue Workbook for the LLP Transmission class, please provide a breakdown of the revenues and billing determinants at both present and proposed rates for each customer that serves all or a portion of its load with behind-the-meter generation.

Response No. TIEC 11-7:

Please see TIEC 11-7, Attachment 1, for billing determinant and revenue data for customers taking As-Available, Maintenance, or Backup service, and the proposed Synchronized Self Generation rate in conjunction with LLP Transmission service during the test year.

Prepared By: Earlyne T. Reynolds Title: Reg Pricing & Analysis Mgr

Sponsored By: Jennifer L. Jackson Title: Reg Pricing & Analysis Mgr

Sponsored By: John O. Aaron Title: Dir Reg Pricing & Analysis

	Basis Amt	201904	201905	201906	201907	201908	201909	201910	201911	201912	202001	202002	202003	Total	Proposed Change in revenue *	
344 LARGE LTG & POWER-TRANS 138 KV																
DM34B	BACK UP DEMAND CHARGE (MANB)	0	0	0	0	0	196,140		0	0	0	0	0	196,140		
DM34C	BACK UP KW RESERVATION DM CHARGE (MANB)	8,480	160,000	160 000	160 000	160,000	120 772	160,000	160,000	160 000	160 000	160,000	160 000	1 729 252		
DM34D	MAINTENANCE POWER DEMAND CHARGE (MANB)	1,212 160	0	0	0	0	0		0	0	0	0	0	1 212,160		
DM34E	MAINTENANCE KW RESERVATION DM (MANB)	0	30,000	30 000	30 000	30,000	30 000	60 000	30,000	0	30,000	60,000	0	330 000		
DM34F	AS AVAILABLE DEMAND CHARGE (MANB)	0	30 000	15,000	30 000	30 000	25 000	35 000	10 000	0	0	15 000	0	190,000		
	Sales of Electricity															
344 LARGE LTG & POWER-TRANS 138 KV																
DM34B	BACK UP DEMAND CHARGE (MANB)	$0 00	$0 00	$0 00	$0 00	$0 00	$70,610 40		$0 00	$0 00	$0 00	$0 00	$0 00	$70,610 40	$81,407 44	
DM34C	BACK UP KW RESERVATION DM CHARGE (MANB)	$12,211 20	$230 400 00	$230,400 00	$230,400 00	$230,400 00	$173,911 68	$230,400 00	$230,400 00	$230,400 00	$230 400 00	$230 400 00	$230,400 00	$2,490,122 88	$2,870,887 57	
DM34D	MAINTENANCE POWER DEMAND CHARGE (MANB)	$206,067 20	$0 00	$0 00	$0 00	$0 00	$0 00		$0 00	$0 00	$0 00	$0 00	$0 00	$206,067 20	$237,576 94	
DM34E	MAINTENANCE KW RESERVATION DM (MANB)	$0 00	$21,600 00	$21,600 00	$21 600 00	$21,600 00	$21,600 00	$43 200 00	$21,600 00	$0 00	$21 600 00	$43,200 00	$0 00	$237 600 00	$273 931 42	
DM34F	AS AVAILABLE DEMAND CHARGE (MANB)	$0 00	$15,300 00	$7,650 00	$15 300 00	$15,300 00	$12,750 00	$17 850 00	$5 100 00	$0 00	$0 00	$7 650 00	$0 00	$96,900 00	$111,716 98	
														3,101,300 48	$3,575,520 34	
	Proposed New Charge**															
	PROPOSED SYNCHONIZED SELF GENERATION BASIS	150 000	150 000	150,000	150,000	150 000	150,000	150,000	150,000	150 000	150,000	150,000	150 000	1 800,000		
$2 20	PROPOSED SYNCHONIZED SELF GENERATION CHARGE	$330 000 00	$330,000 00	$330,000 00	$330,000 00	$330,000 00	$330,000 00	$330 000 00	$330,000 00	$330 000 00	$330 000 00	$330 000 00	$330,000 00	$3,960 000 00	$3,960,000 00	
														3,101,300 48	$7,535,520 34	143%

*The proposed change in revenue is based on the present test year revenue plus the LLP transmission class propsed increase percentage amount for each service

**The proposed Synchonzided Self Generation charge is the based on synchrozied self-generation kW * the proposed rate of $2 20

PUC DOCKET NO. 46449
SOAH DOCKET NO. 473-17-1764

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2018 MAR 19 PM 3: 18
PUBLIC UTILITY COMMISSION
FILING CLERK

APPLICATION OF SOUTHWESTERN ELECTRIC POWER COMPANY FOR AUTHORITY TO CHANGE RATES	§ § §	PUBLIC UTILITY COMMISSION OF TEXAS

ORDER ON REHEARING

This order addresses the application of Southwestern Electric Power Company (SWEPCO) for authority to change its rates, filed on December 16, 2016. SWEPCO originally sought a $69 million increase to its Texas retail revenue requirement, primarily to reflect investments in environmental controls. However, SWEPCO also proposed a significant modification to the manner in which its transmission costs should be recovered. In addition, SWEPCO sought additional cost recovery for vegetation management, rate-case expenses, and a regulatory asset for certain costs under the Southwest Power Pool's open-access tariff.

A hearing on the merits was held between June 5 and June 15, 2017 at the State Office of Administrative Hearings (SOAH). On September 22, 2017, the SOAH administrative law judges (ALJs) filed their proposal for decision (PFD) in which they recommended a Texas retail revenue requirement increase of approximately $51 million. The SOAH ALJs rejected SWEPCO's new method to recover transmission costs and recommended granting its requested rate-case expenses, and regulatory asset. In response to parties' exceptions and replies to the PFD, on November 8, 2017, the SOAH ALJs filed a letter making changes to the PFD.

Except as discussed in this order, the Commission adopts the PFD as modified, including findings of fact and conclusions of law. The Commission's decisions result in a Texas retail base-rate revenue requirement of $369,234,023, which is an increase of $50,001,133 from SWEPCO's present Commission-authorized Texas retail base-rate revenue requirement. New findings of fact 17A through 17J are added to address the procedural history of this docket after the close of the evidentiary record at SOAH. The Commission incorporates by reference the abbreviations table provided in the PFD.

625

307. Under the investment method, most poles are directly assigned to primary or secondary service. The number of connections associated with a pole is only taken into account in cases where a pole is shared by primary and secondary distribution facilities.

308. The investment method appropriately takes into account the total investment in the poles, rather than merely the number of poles or length of conductor.

309. The size and length of a pole used in the construction of distribution facilities depends on operational requirements specific to the particular installation involved, without regard to whether primary or secondary distribution facilities are under construction.

310. The investment method is reasonable and should be adopted for purposes of allocating FERC Account 364 and 365 costs between the primary and secondary distribution facilities.

Revenue Distribution and Rate Design

Revenue Distribution

311. Most of the parties to this case agree that some level of gradualism should be employed in the revenue distribution.

312. SWEPCO's proposed approach of grouping major rate classes for purposes of implementing the revenue distribution was approved by the Commission in SWEPCO's most recent base-rate proceeding, Docket No. 40443.

313. SWEPCO's proposed revenue distribution moves all customer classes closer to cost of service, sets larger customer groups of similar size and type at cost of service, and facilitates sustainable migration among customer rates.

314. SWEPCO's proposed gradualism methodology, which reduces the subsidization among individual rate classes, is reasonable and should be adopted, except that a class's present revenues should be evaluated inclusive of existing TCRF and DCRF revenues, which are base-rate related revenues.

314A. Any gradualism methodology should evaluate the differences in the actual rates that customers pay.

PUC DOCKET NO. 46449
SOAH DOCKET NO. 473-17-1764

APPLICATION OF SOUTHWESTERN	§	PUBLIC UTILITY COMMISSION
ELECTRIC POWER COMPANY FOR	§	
AUTHORITY TO CHANGE RATES	§	OF TEXAS

ORDER ON REHEARING

This order addresses the application of Southwestern Electric Power Company (SWEPCO) for authority to change its rates, filed on December 16, 2016. SWEPCO originally sought a \$69 million increase to its Texas retail revenue requirement, primarily to reflect investments in environmental controls. However, SWEPCO also proposed a significant modification to the manner in which its transmission costs should be recovered. In addition, SWEPCO sought additional cost recovery for vegetation management, rate-case expenses, and a regulatory asset for certain costs under the Southwest Power Pool's open-access tariff.

A hearing on the merits was held between June 5 and June 15, 2017 at the State Office of Administrative Hearings (SOAH). On September 22, 2017, the SOAH administrative law judges (ALJs) filed their proposal for decision (PFD) in which they recommended a Texas retail revenue requirement increase of approximately \$51 million. The SOAH ALJs rejected SWEPCO's new method to recover transmission costs and recommended granting its requested rate-case expenses, and regulatory asset. In response to parties' exceptions and replies to the PFD, on November 8, 2017, the SOAH ALJs filed a letter making changes to the PFD.

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274. The use of 10 years of data is more sensitive to weather patterns during the test year.

275. The weather-normalization adjustment should be applied to adjust billing units and allocation factors for a 10-year weather-normalization period, based on the class billing determinants and external allocation factors used to calculate rates using a 10-year weather-normalization period.

Jurisdictional Cost Allocation

276. SWEPCO's proposal to base the jurisdictional allocation of transmission capacity costs on the 12 Coincident Peak (12CP) methodology is reasonable and consistent with Commission precedent.

Cost Allocation

Allocation of Production Costs

277. SWEPCO allocates production costs to various classes under the average and excess Demand-4 coincident peak (A&E-4CP) methodology. This methodology allocates a percentage of costs, equal to the system load factor, based on average demand, and the remainder of those costs based on excess demand.

278. In SPS Docket No. 43695, the only Commission docket in which this issue has been litigated, the Commission determined that the system load factor should be calculated by using the single annual coincident peak, rather than the average of four coincident peaks.

279. SWEPCO used the single coincident peak in calculating its system load factor for Schedule O-1.6.

280. The use of the annual coincident peak in calculating system load factor is consistent with the definition of load factor in the Commission's rules.

281. The use of the annual coincident peak for calculating system load factor is consistent with SWEPCO's generation and transmission planning.

282. The use of the annual coincident peak for calculating system load factor is consistent with the National Association of Regulatory Commissioners (NARUC) manual.

283. The use of the annual coincident peak for calculating system load factor is consistent with SPP planning.

284. In using the A&E-4CP methodology, SWEPCO should calculate its system load factor using the single annual coincident peak.

Class Cost Allocation of Transmission Costs

285. SWEPCO proposes to allocate transmission costs to retail classes based on the 12CP demand allocator.

286. SWEPCO is a summer-peaking utility.

287. The electricity demands in the summer months are the primary drivers for the amount of transmission capacity needed for SWEPCO to provide reliable service.

288. SWEPCO's demands during the four summer months ranged from 4623 MW to 5149 MW, while no off-peak month had demand in excess of 4051 MW.

289. The Commission has a longstanding policy of allocating transmission costs based primarily on peak demands in the four summer months.

290. SWEPCO has submitted the same position in support of the 12CP methodology in this case that it did in its prior case.

291. In Docket No. 40443, the Commission rejected SWEPCO's proposal to allocate transmission costs based on the 12CP methodology, and instead required SWEPCO to use the A&E/4CP methodology.

292. The A&E/4CP method for allocating transmission costs to the retail classes is standard and the most reasonable methodology.

293. SWEPCO should use the A&E/4CP method for allocating transmission costs to the retail classes.

Major Customer Account Representative Expense

294. A major account representative is a utility employee who provides services either to large customers or to national chains.

295. During the test year, SWEPCO (total company) spent $1,082,908 on major account representatives.

CHAPTER 25. SUBSTANTIVE RULES APPLICABLE TO ELECTRIC SERVICE PROVIDERS.

Subchapter J. COSTS, RATES, AND TARIFFS.

DIVISION 1. RETAIL RATES.

§25.239. Transmission Cost Recovery Factor for Certain Electric Utilities.

(a) **Application.** The provisions of this section apply to an electric utility that operates solely outside of the Electric Reliability Council of Texas in areas of Texas included in the Southwest Power Pool or the Western Electricity Coordinating Council and that owns or operates transmission facilities.

(b) **Definitions.**

(1) **Approved transmission charges (ATC)** — Wholesale transmission charges approved by a federal regulatory authority that are not being recovered through the electric utility's other retail or wholesale rates and that are appropriately allocated to Texas retail customers. The charges may relate to the use of transmission facilities owned and operated by another transmission service provider or regional transmission organization, including transmission-related administrative fees but not including dispatch fees, congestion charges, costs incurred to hedge congestion charges, or ancillary service charges.

(2) **Transmission invested costs (TIC)** — The net change in the electric utility's transmission investment costs including additions, upgrades, and retirements as booked in FERC accounts 350-359, and accumulated depreciation.

(c) **Recovery authorized.** The commission, after notice and hearing, may allow an electric utility to recover its reasonable and necessary costs for transmission infrastructure improvement and changes in wholesale transmission charges to the electric utility under a tariff approved by a federal regulatory authority to the extent that the costs or charges have not otherwise been recovered and are incurred after December 31, 2005. Any such recovery shall be made through the use of a transmission cost recovery factor (TCRF) approved by an order of the commission. The TCRF shall be calculated pursuant to subsection (d) of this section. If a utility has not had a base rate case with a final order issued after December 2005, the utility shall not be eligible for recovery under this provision without first obtaining a final order in a base rate case.

(d) **Transmission cost recovery factor (TCRF).** The TCRF shall be determined by the following formula:

$$\text{TCRF} = \frac{RR * ClassALLOC}{BD}$$

Where:	TCRF = transmission cost recovery factor in dollars per unit, for billing each customer class.
	RR = transmission cost recovery factor revenue requirement, calculated pursuant to subsection (e) of this section.
	ClassALLOC = the customer class allocation factor used to allocate the transmission revenue requirement in the utility's most recent base rate case.
	BD = each customer class's annual billing determinant (kilowatt-hour, kilowatt, or kilovolt-ampere) for the previous calendar year.

(e) **Transmission cost recovery factor revenue requirement (RR).** For an electric utility subject to this section, the transmission cost recovery factor revenue requirement (RR) shall be calculated by using the following formula:

RR = [revreqt + ATC]*ALLOC	
Where:	Revreqt = the sum of the return on TIC, net of accumulated depreciation and associated accumulated deferred income taxes, plus investment-related expenses such as income taxes, other associated taxes, depreciation, and transmission–related miscellaneous revenue credits, but not including operation and maintenance expenses or administrative expenses. The return on TIC shall be calculated by multiplying the TIC by the utility's weighted-average cost of capital (WACC) as established for the utility in a final commission order in a base rate case, provided that the order was filed within three years prior to the initiation of the TCRF docket. Otherwise, a proxy WACC shall be used, with a cost of equity of 10%; and the capital structure and cost of debt as reported in the utility's most recent Earnings Monitoring Report filed pursuant to §25.73 of this title (relating to Financial and Operating Reports), adjusted for known and measurable changes.
	Transmission Invested Costs (TIC) is defined in subsection (b)(2) of this section.
	Approved Transmission Charges (ATC) is defined in subsection (b)(1) of this section.
	ALLOC = the utility's Texas retail allocation of transmission revenue requirements, as established in the utility's most recent base rate case.

(f) **Setting and amending the TCRF.** An electric utility that is subject to this section may file an application to set or amend a TCRF. The commission staff may also file an application to amend a TCRF. An electric utility may not apply to amend its TCRF more frequently than once each calendar year, but a TCRF shall be reviewed or amended at least once every three years. Upon completion of a base rate case for a utility, the TCRF shall be set to zero. In a docket in which the TCRF is reviewed or amended, the commission may order the refund of any previous over-recovery, but the commission shall not order the surcharge of any under-recovery. An over-recovery shall be considered to have occurred if the revenues from the TCRF were greater than the costs that the TCRF was intended to recover.

(g) **TCRF forms.** The commission may develop forms for TCRF applications and for monitoring the revenues from a TCRF. If the commission develops and approves such forms, an electric utility shall use the forms as required by the instructions accompanying the form.

(d) The commission may provide a mechanism to allow an electric utility that has a noncontiguous geographical service area and that purchases power for resale for that noncontiguous service area from electric utilities that are not members of the Electric Reliability Council of Texas to recover purchased power costs for the area in a manner that reflects the purchased power cost for that specific geographical noncontiguous area. The commission may not require an electric cooperative corporation to use the mechanism provided under this section unless the electric cooperative corporation requests its use.

(V.A.C.S. art. 1446c-0, sec. 2.212(g)(3).)

Sec. 36.206. MARK-UPS.

(a) A cost recovery factor established for the recovery of purchased power costs may include:

(1) the cost the electric utility incurs in purchasing capacity and energy;

(2) a mark-up added to the cost or another mechanism the commission determines will reasonably compensate the utility for any financial risk associated with purchased power obligations; and

(3) the value added by the utility in making the purchased power available to customers.

(b) The mark-ups and cost recovery factors, if allowed, may be those necessary to encourage the electric utility to include economical purchased power as part of the utility's energy and capacity resource supply plan.

(V.A.C.S. art. 1446c-0, sec. 2.1511.)

Sec. 36.207. USE OF MARK-UPS.

Any mark-ups approved under Section 36.206 are an exceptional form of rate relief that the electric utility may recover from ratepayers only on a finding by the commission that the relief is necessary to maintain the utility's financial integrity.

(V.A.C.S. art. 1446c-0, sec. 2.001(d) (part).) (Amended by Acts 1999, 76th Leg., R.S., ch. 405 (SB 7), § 28.)

Sec. 36.208. PAYMENT TO QUALIFYING FACILITY.

In establishing an electric utility's rates, the regulatory authority shall:

(1) consider a payment made to a qualifying facility under an agreement certified under Subchapter C, Chapter 35, to be a reasonable and necessary operating expense of the electric utility during the period for which the certification is effective; and

(2) allow full, concurrent, and monthly recovery of the amount of the payment.

(V.A.C.S. art. 1446c-0, sec. 2.209(e).)

Sec. 36.209. RECOVERY BY CERTAIN NON-ERCOT UTILITIES OF CERTAIN TRANSMISSION COSTS.

(a) This section applies only to an electric utility that operates solely outside of ERCOT in areas of this state included in the Southeastern Electric Reliability Council, the Southwest Power Pool or the Western Electricity Coordinating Council and that owns or operates transmission facilities.

(b) The commission, after notice and hearing, may allow an electric utility to recover on an annual basis its reasonable and necessary expenditures for transmission infrastructure improvement costs and changes in wholesale transmission charges to the electric utility under a tariff approved by a federal regulatory authority to the extent that the costs or charges have not otherwise been recovered. The commission may allow the electric utility to recover only the costs allocable to retail customers in the state and may not allow the electric utility to over-recover costs.

(Added by Acts 2005, 79th Leg., R.S., ch. 1024 (HB 989), § 1.) (Amended by Acts 2009, 81st Leg., R.S., ch. 1226 (SB 1492), § 1 (amended subsec. (a)).)

Southwestern Electric Power Company
TCRF Revenue Requirement Calculation
For the Test Year Ending March 31, 2020

Line No.	(A) Component	(B) Total Company	(C) Texas Retail Transmission Function	(D) Texas Retail Amount Included in SWEPCO Base Rate Order	(E) Net Change Not Included In Base Rate Order (C - D)
1	**TIC:**				
2	Transmission Plant in Service	$2,066,218,993	$904,072,262	$904,072,262	$0
3	Accumulated Depreciation	(570,785,047)	(249,746,484)	(249,746,484)	0
4	Net Plant in Service	$1,495,433,946	$654,325,778	$654,325,778	$0
5					
6	Accumulated Deferred Taxes	(208,942,255)	(91,422,496)	(91,422,496)	0
7					
8	**Total TIC**	$1,286,491,691	$562,903,283	$562,903,283	$0
9					
10	WACC	7 22%	7 22%	7 22%	
11					
12	**Return on TIC**	$92,935,304	$40,663,759	$40,663,759	$0
13					
14					
15					
16	**Investment-Related Expenses:**				
17	Depreciation Expense	$47,933,847	$20,973,412	$20,973,412	$0
18	Income Tax Expense - Note 1	34,779,087	16,544,686	16,544,686	0
19	Other Associated Taxes	67,742,851	6,447,554	6,447,554	0
20	Revenue Credits	(172,655,780)	(75,666,738)	(75,666,738)	0
21	**Total Investment-Related Expenses**	($22,199,994)	($31,701,086)	($31,701,086)	$0
22					
23	**Revreqt (line 12 + line 21)**	$70,735,310	$8,962,673	$8,962,673	$0
24					
25	**ATC:**				
26	SPP Charges and Fees	$157,881,876	$68,652,821	$68,652,821	$0
27	Non-SPP Charges	6,005,430	2,631,891	2,631,891	0
29	Other Transmission Charges	914,530	400,795	400,795	0
32	**Total ATC**	$164,801,836	$71,685,507	$71,685,507	$0
33					
34	**RR (line 23 + line 32)**	$235,537,145	$80,648,180	$80,648,180	$0

Note (1) Income Tax Expense is calculated for the Texas Retail Transmission Function

Southwestern Electric Power Company
TCRF Revenue Requirement Calculation
For the Year Ending September 30, 2018

Line No.	(A) Component	(B) Transmission Total Company	(C) Texas Retail Transmission Function	(D) Texas Retail Trans Amount Included in SWEPCO Base Rates Docket No. 46449	(E) Net Change Not Included In Base Rate Order (C - D)
1	**TIC:**				
2	Transmission Plant in Service	$1,805,659,249	$710,197,756	$578,810,052	$131,387,704
3	Accumulated Depreciation	(547,978,331)	(215,395,573)	(196,049,290)	(19,346,283)
4	Net Plant in Service	$1,257,680,917	$494,802,182	$382,760,762	$112,041,420
5					
6	Accumulated Deferred Taxes	(274,882,178)	(108,048,945)	(88,349,265)	(19,699,680)
7					
8	**Total TIC**	$982,798,739	$386,753,237	$294,411,497	$92,341,740
9					
10	WACC	7 18%	7 18%	7 18%	
11					
12	**Return on TIC**	$70,541,559	$27,759,678	$21,131,739	$6,627,939
13					
14					
15					
16	**Investment-Related Expenses:**				
17	Depreciation Expense	$36,954,970	$14,526,026	$12,543,415	$1,982,611
18	Income Tax Expense - Note 1	11,206,626	4,693,856	3,548,358	1,145,498
19	Other Associated Taxes	63,653,439	5,063,426	3,745,805	1,317,621
20	Revenue Credits	(203,220,343)	(79,880,565)	(60,242,621)	(19,637,944)
21	**Total Investment-Related Expenses**	($91,405,308)	($55,597,257)	($40,405,043)	($15,192,214)
22					
23	**Revreqt (line 12 + line 21)**	($20,863,749)	($27,837,580)	($19,273,305)	($8,564,275)
24					
25	**ATC:**				
26	SPP Charges and Fees	$200,961,524	$77,379,409	$56,214,726	$21,164,683
27	Wheeling Expense	513,035	171,035	161,208	9,827
28	Other Transmission Charges	1,068,854	420,138	394,452	25,687
29	**Total ATC**	$202,543,413	$77,970,583	$56,770,386	$21,200,197
30					
31	**RR (line 23 + line 29)**	$181,679,664	$50,133,003	$37,497,081	$12,635,922
32					
33	Settlement Adjustments	$0	$0	$0	$0
34					
35	Adjusted TCRF Revenue Requirement	$181,679,664	$50,133,003	$37,497,081	$12,635,922

THOMPSON & KNIGHT LLP

TO:	Texas Industrial Energy Consumers (TIEC)
FROM:	Rex D. VanMiddlesworth Katie Coleman
DATE:	June 7, 2019
SUBJECT:	Treatment of Electricity Self-Supplied by Retail Customers

INTRODUCTION

This memorandum addresses the Southwest Power Pool's (SPP) treatment of electricity produced and consumed on-site behind a retail customer's meter (Retail BTM Generation) in assessing transmission charges under Section 34.4 of the SPP Open Access Transmission Tariff (OATT). This analysis is limited to electricity that is produced and consumed on-site by a retail customer without the use of any SPP Network Customer's[1] electric grid. This Retail-BTM-Generation issue is distinct from the issues related to load served by generation located behind an SPP Network Customer's Delivery Point but in front of any retail customer's meter (Wholesale BTM Generation), which *does* require use of the Network Customer's grid.[2] It is also distinct from the situation for Independent System Operators or Regional Transmission Organizations where retail choice has been introduced and a retail customer itself may be the "Network Customer" under the applicable OATT. There is currently no retail customer choice within the SPP footprint.

Retail BTM Generation takes a variety of forms, including residential and commercial rooftop solar installations and qualifying small power production and cogeneration facilities (QFs). Generally, this generation is not economically dispatched; it is used as available to provide electricity behind a customer's retail meter. In some situations, particularly with QFs that are highly integrated with on-site industrial processes, some of the load served by the Retail BTM Generation will never be served from the grid, as any reduction in electricity and steam production

[1] "Network Customer" is defined as "an entity receiving transmission service pursuant to [SPP's] Network Integration Transmission Service..." SPP OATT, Section 1, Definitions.

[2] This distinction between generation behind a retail meter and generation in front of a retail meter was recognized in the most recent Revision Request developed by the SPP Regional Tariff Working Group. *See* SPP Revision Request Recommendation Report No. 241 at 5.

from the QF will be accompanied by a reduction in electricity usage. Often the utility has no way of knowing the amount of a retail customer's on-site usage that is being served by that retail customer's own generation, since the utility is neither providing generation nor transmission and distribution (T&D) services for that usage.

Wholesale BTM Generation, on the other hand, is typically electric utility generation that is indistinguishable from a Network Resource. Rather than being fully utilized whenever available, Wholesale BTM Generation is generally economically dispatched by the Network Customer, as is other electric utility generation. Further, Wholesale BTM Generation provides electricity that the Network Customer then transmits over its electrical grid to serve the Network Customer's load.

The issues relating to Wholesale BTM Generation have been addressed on a number of occasions by the Federal Energy Regulatory Commission (FERC), which has held that a Network Customer's actual load at the time of its monthly peak is not to be reduced by the amount of its Wholesale BTM Generation.[3] Neither the language nor the rationales of those decisions, however, are applicable to electricity produced and consumed on-site by a retail customer, which is neither being provided by the Network Customer nor using its T&D system and, accordingly, is simply not a part of the Network Customer's load. With respect to SPP, neither the specific provisions of the SPP OATT nor the decisions of FERC support including a retail customer's on-site self-supplied electricity as "Network Load" for purposes of assessing transmission charges under Section 34.4 of the SPP OATT.

SECTION 34.4 OF THE SPP OATT BY ITS TERMS DOES NOT INCLUDE ELECTRICITY SELF-SUPPLIED BY A RETAIL CUSTOMER IN THE DEFINITION OF "NETWORK CUSTOMER'S MONTHLY NETWORK LOAD."

SPP assesses transmission charges to regulated utilities as "Network Customers," based on their "Network Load." In SPP, Network Customers are utilities, municipalities, and cooperatives, not end-use customers. The definition of "Network Customer's Monthly Network Load" in Section 34.4 of the SPP OATT does not include electricity that is generated and consumed on-site by a retail customer. The SPP OATT defines "Network Customer's Monthly Network Load" as follows:

[3] FERC Order Nos. 888, 888-A, and 890.

The Network Customer's monthly Network Load is its hourly load (60 minute, clock-hour); provided, however, the Network Customer's monthly Network Load will be *its* hourly load coincident with the monthly peak of the Zone where the Network Customer load is physically located.[4]

Note that the definition only includes the *Network Customer's* hourly load coincident with the monthly peak. The "Network Customer" is defined as the "entity receiving transmission service pursuant to [SPP's] Network Integration Transmission Service under Part III of the Tariff."[5] If a retail customer of an integrated utility is generating its own electricity behind its own meter for its own use at the time of a Network Customer's monthly peak, that use is simply not a part of the *Network Customer's* "hourly load coincident with the monthly peak." That applies whether the electricity is provided by rooftop solar or by a qualifying facility. The Network Customer is simply not providing the electricity produced and consumed on-site by a retail customer. Indeed, the Network Customer would likely not even know how much electricity, if any, the retail customer is providing to itself at the time of the monthly peak, since electricity that is self-provided is generally not even metered by the utility. In any event, electricity that is being self-provided behind a retail meter is not being provided by the utility, nor is it being delivered over the utility's T&D system. Accordingly, it cannot be fairly characterized as the *utility's* "hourly load coincident with the monthly peak."

Not true for Eastman

Importantly, the above analysis does not apply to whatever portion of a Network Customer's load is being served by Wholesale BTM Generation—which does use the Network Customer's transmission or distribution system to deliver electricity to retail customers of the Network Customer. That load *is* a part of the Network Customer's load. To the extent that load is being served by Wholesale BTM Generation at the time of the monthly coincident peak, it would fall within the definition of "Network Customer's Monthly Network Load" under Section 34.4. That is not true, however, of electricity being provided by a retail customer's own on-site generation at the time of the monthly coincident peak.

[4] SPP OATT, Section 34.4. (italics supplied)

[5] SPP OATT, Section 1, Definitions.

<u>SPP'S NETWORK CUSTOMERS HAVE GENERALLY NOT CONSTRUED SECTION 34.4 TO INCLUDE RETAIL CUSTOMERS' SELF-SUPPLIED ELECTRICITY.</u>

Numerous Network Customers in SPP have properly calculated their Monthly Network Load without adding in electricity that they do not supply or deliver, but that is instead self-supplied by retail customers. SPP recently surveyed its 62 transmission customers with Network Load. Those results indicate that a large number of SPP's Network Customers are properly applying Section 34.4 of the OATT and not attempting to reach behind their customers' retail meters to determine if those customers are supplying any of their own electricity.[6] The responses make clear that those Network Customers have reviewed and considered the SPP OATT and do not read it as requiring the addition of their retail customers' self-supplied electricity to the Network Customer's actual Network Load.[7]

It appears that at least one SPP utility (SPS) has adopted a different interpretation, at least in part. SPS appears to have been identifying and adding at least some of its customers' self-supplied electricity to its Network Load calculation.[8] But even SPS does not apply Section 34.4 to include all electricity self-supplied by its customers, as SPS apparently does not identify and include load served by rooftop solar or other small customer generation. But since Section 34.4 of the SPP OATT makes no distinction between large and small self-supplied loads, they must either all be included or all be excluded. SPS's idiosyncratic approach does neither. Further, as noted by one respondent to the SPP survey, utilities generally have no way of metering the output of solar panels or other generation behind retail meters.[9]

In summary, SPP's Network Customers, who have operated under the OATT for many years, have generally not construed the OATT to require them to somehow meter and report their retail customers' self-supplied electricity usage at the time of the monthly peak as if it were being supplied by the Network Customer. Their interpretation is correct. And there do not appear to be any transmission customers that interpret Section 34.4 to require them to somehow look behind all of their retail customers' meters and identify all electricity being self-supplied at the time of the monthly peak.

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[6] SPP Network Load Reporting Presentation, Mar. 28, 2018, at Slides 26-32.

[7] *Id* at Slides 30-32.

[8] SPP Revision Request Recommendation Report RR 158 (Feb. 22, 2016) at 4.

[9] SPP Network Load Reporting Presentation, Mar. 28, 2018 at Slide 31.

<u>THE REJECTION OF PROPOSALS TO AMEND SECTION 34.4 OF THE SPP OATT TO INCLUDE RETAIL CUSTOMERS' SELF-SUPPLIED ELECTRICITY DEMONSTRATES THAT SUCH USAGE IS NOT INCLUDED UNDER THE CURRENT LANGUAGE OF SECTION 34.4.</u>

SPP's recent efforts to amend Section 34.4 of the SPP OATT confirm that the *current* version does not include electricity self-supplied by retail customers. In 2017, the SPP Regional Tariff Working Group (RTWG) took up this issue and proposed revisions to the OATT.[10] The proposed revisions first properly distinguished between Wholesale BTM Generation and Retail BTM Generation.[11] Then the RTWG proposed to amend Section 34.4 to *add* load served by Retail BTM Generation greater than 1 MW to the definition of Monthly Network Load.[12] The proposed tariff amendments put forth in Revision Request (RR) 241 make clear that the current tariff language does not include load served by Retail BTM Generation.

First, the proposed revision specifically added language to *include* load served by Retail BTM Generation larger than 1 MW. This addition would have been unnecessary if the current language already included all load served by Retail BTM Generation. Even more telling, the proposed OATT change was completely silent on load served by Retail BTM Generation of less than 1 MW. Accordingly, the treatment of load self-served by that type of generation would continue as it is under current Section 34.4. The RR 241 Recommendation Report makes clear that it did *not* intend to include load served by Retail BTM Generation smaller than 1 MW, which must mean that the existing language of Section 34.4 does not include it. That is, the omission of any change concerning electricity self-supplied by Retail BTM Generation smaller than 1 MW—coupled with the intent not to include it as Network Load—confirms that the current provision does not treat *any* load self-supplied by Retail BTM Generation as Network Load. Since the proposed amendment to explicitly include load served by Retail BTM Generation that is larger than 1 MW failed, the existing exclusion of *all* load self-supplied by Retail BTM Generation remains in place.

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[10] SPP Revision Request Recommendation Report RR 241.

[11] *Id.* at p.5, para B.2 and 3.

[12] *Id.* at p.5, para B.3.

IDENTICAL LANGUAGE IN MISO'S TARIFF HAS BEEN CONSTRUED BY MISO AND FERC TO NOT INCLUDE LOADS SERVED BY RETAIL BTM GENERATION IN ALLOCATING TRANSMISSION COSTS.

The MISO OATT has language that is virtually identical to SPP's on the allocation of "Network Load" costs.[13] When Entergy (which had substantial cogeneration on its system) was integrated into MISO, the issue of how to treat load served by Retail BTM Generation on the Entergy system was specifically addressed. MISO determined and reflected in its QF Integration Plan that, under the MISO OATT, Entergy should only report a QF's *net* usage for purpose of determining Network Load.[14] That is, the electricity produced and consumed on site was not to be added to Network Load. No change to the definition of Network Load was proposed. The MISO QF Integration Plan was presented to FERC in a complaint proceeding, and FERC concluded that the MISO QF Integration Plan merely provided additional detail about how the MISO OATT applies to QFs, so no tariff change was required.[15] In other words, MISO's existing tariff—which is identical on this point to SPP's—does not provide for adding electricity self-supplied behind the retail meter by QF Generation to Network Load, and MISO's Integration Plan simply provided additional detail on that point.[16]

FEDERAL AND STATE REGULATIONS REGARDING QFS PROHIBIT UTILITIES FROM ASSUMING THAT ELECTRICITY SUPPLIED BY A QF IS BEING SERVED BY THE UTILITY AT THE TIME OF PEAK.

Much of the self-supplied electricity in SPP is produced by QFs under the federal and state PURPA regulations. When those regulations were adopted, a number of parties argued that since the utility must stand ready to provide back-up power at any time, a retail customer served by a QF should be allocated transmission and production costs as if it were taking its power from the system rather than from the QF at the time of the monthly peak. Indeed, the Texas PUC identified four utilities in the State of Texas that billed on that basis.[17] Those utilities argued that "in order

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[13] MISO OATT, Section 34.2.

[14] QF Generator Readiness for MISO Relatively Coordination and Market Integration, Oct. 10, 2012 at 17-18.

[15] 155 FERC ¶ 61, 068 (2016) at 76.

[16] MISO is currently finalizing tariff language changes that will further clarify this practice and seek to extend the practice to Wholesale BTM Generation to the extent load served behind the meter by the Wholesale BTM Generation is either lost or cannot be served when the Wholesale BTM Generation is not operating. BTMG/btmg Gross Vs. Net Load for NITS Billing, MISO Planning Advisory Committee, April 17, 2019.

[17] Cogeneration and Small Power Production in Texas, Staff Report, Jul. 1983 at 38.

Confirm that we have this report

to be prepared to provide back-up energy at a moment's notice, the utility must invest in generation and transmission facilities to the same degree as if that customer demanded energy on a regular basis."[18] Both FERC and the Texas PUC unequivocally rejected the argument that load served by on-site QF Generation should be treated as if it were instead on the utility's system at the time of peak. In doing so, FERC specifically provided that the rates for standby power "not be based on an assumption (unless supported by factual data) that forced outages or other reductions in output by all qualify facilities on an electric utility's system will occur simultaneously or during the time of system peak, or both."[19]

The Texas PUC has adopted the same position as the FERC on this issue.[20] Shortly after FERC adopted its regulations, the PUC Staff recommended the elimination of back-up rates with 100% ratchets.[21] The PUC subsequently implemented the Staff's recommendations; 100% ratchets were eliminated, and rates for back-up power are not based on the assumption that the full load was taking power from the system at the time of the monthly peak.

Thus, the treatment of electricity provided by BTM Generation that was proposed (and rejected) in SPP's RR 241 has also been rejected by both FERC and the Texas PUC. The rejected SPP proposal would have allocated costs exactly as if the utility were actually providing service to load served by Retail BTM Generation at the time of the Network Customer's monthly coincident peak, without any basis in fact for that assumption. If that type of allocation were adopted by SPP, utilities would then have to develop retail rates for back-up customers that incorporate this assumption, even though that is explicitly prohibited by both state and federal regulations.

FERC ORDER NOS. 888, 888-A, AND 890 ADDRESS LOAD SERVED BY WHOLESALE BTM GENERATION, NOT RETAIL BTM GENERATION.

In FERC Order Nos. 888, 888-A and 890, FERC dealt with arguments by electric cooperatives and municipal utilities that they should be able to net their own Wholesale BTM Generation against their Network Load. Those arguments related to generation that actually used the Network Customer's T&D system to serve the Network Customers load, not electricity that

[18] *Id.*

[19] 18 CFR §292.305(c)(i).

[20] PUC Subst. Rules § 25.242 (k) (3).

[21] Cogeneration and Small Power Production in Texas, Staff Report, Jul. 1983 at 51.

was self-supplied by a retail customer without any use of the Network Customer's system. For example, FERC Order No. 888 noted that those customers with load served behind the meter could obtain alternative transmission service for that load,[22] an option unavailable to a retail customer in SPP served by a QF or rooftop solar. In fact, one of the arguments by those advocating for netting loads served by Wholesale BTM Generation was that doing so was necessary to avoid discriminatory treatment of Network Customers as compared to retail native load customers, whose self-supplied usage would not be allocated transmission costs.[23] Specifically, CEPCO argued that since a retail customer's load served by its own Retail BTM Generation is not included in the allocation of transmission costs, neither should a Network Customer's load served by Wholesale BTM Generation.[24] The requests for rehearing of FERC Order No. 888 also make clear that the co-ops and municipalities were addressing Wholesale BTM Generation, not Retail BTM Generation.[25]

A careful reading of FERC Order Nos. 888, 888-A and 890 shows that FERC was not attempting to reach behind retail customers' meters to capture electricity that was self-supplied by rooftop solar or cogeneration. It is clear from the context of those orders that when FERC referred to "customers," it meant Network Customers, *not* the individual retail customers of those Network Customers.[26] Further, the reference in those orders to "discrete points of delivery" is to the Network Customer's discrete point of delivery, not to the meter of a retail customer. That is made clear by FERC's conclusion that "customers" could exclude particular load if they obtained alternative transmission service (*i.e.* point-to-point),[27] an option that is not available to retail customers of integrated utilities. If there were any question whether FERC Order No. 888 required the inclusion of retail customer's self-supplied electricity, one need only look at FERC's

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22 FERC Order No. 888 at 297.

23 FERC Order No. 888 Docket; Initial Comments of Cajun Electric Power Cooperative, Inc. (CEPCO) (Aug. 7, 1995). Noting that QF load behind the meter would not be included in the load ratios shown under the OATT.

24 *Id.*

25 For example AMP-Ohio complained that numerous municipalities have installed generation to serve local loads, and they sought an offset against their NITS load, so that those municipalities would not have to rely on point-to-point service. FERC Order No. 888 Docket; Request for Clarification and Rehearing of American Municipal Power-Ohio, Inc. (AMP-OH) at 15-17 (May 24, 1996).

26 See for example, FERC Order No. 888 at 297; FERC Order No. 888-A at 242, 250; FERC Order No. 890, ¶1614. In each instance and elsewhere throughout the Orders, it is clear that "customer" refers to Network Customers, not retail customers of integrated utilities.

27 FERC Order No. 888 at 297, 317.

conclusion on the allocation of Network Service costs. FERC noted that the method it ordered is "based on readily available data."[28] That statement would certainly not have been true if FERC were requiring Network Customers to somehow look behind the meter of every retail customer to determine how much electricity it was self-generating from a QF, rooftop solar, or other Retail BTM Generation.

Those misreading the FERC orders ultimately fail to recognize that the term "customer" therein refers to Network Customers, not individual retail customers. If an individual retail customer is serving a portion of its load with rooftop solar or other Retail BTM Generation, that load is not the load of the Network Customer at that time, and there is nothing for the Network Customer to exclude. Nothing in FERC Order Nos. 888, 888-A, or 890 requires looking behind a retail customer's meter to determine whether that customer is providing some or all of its own electricity.

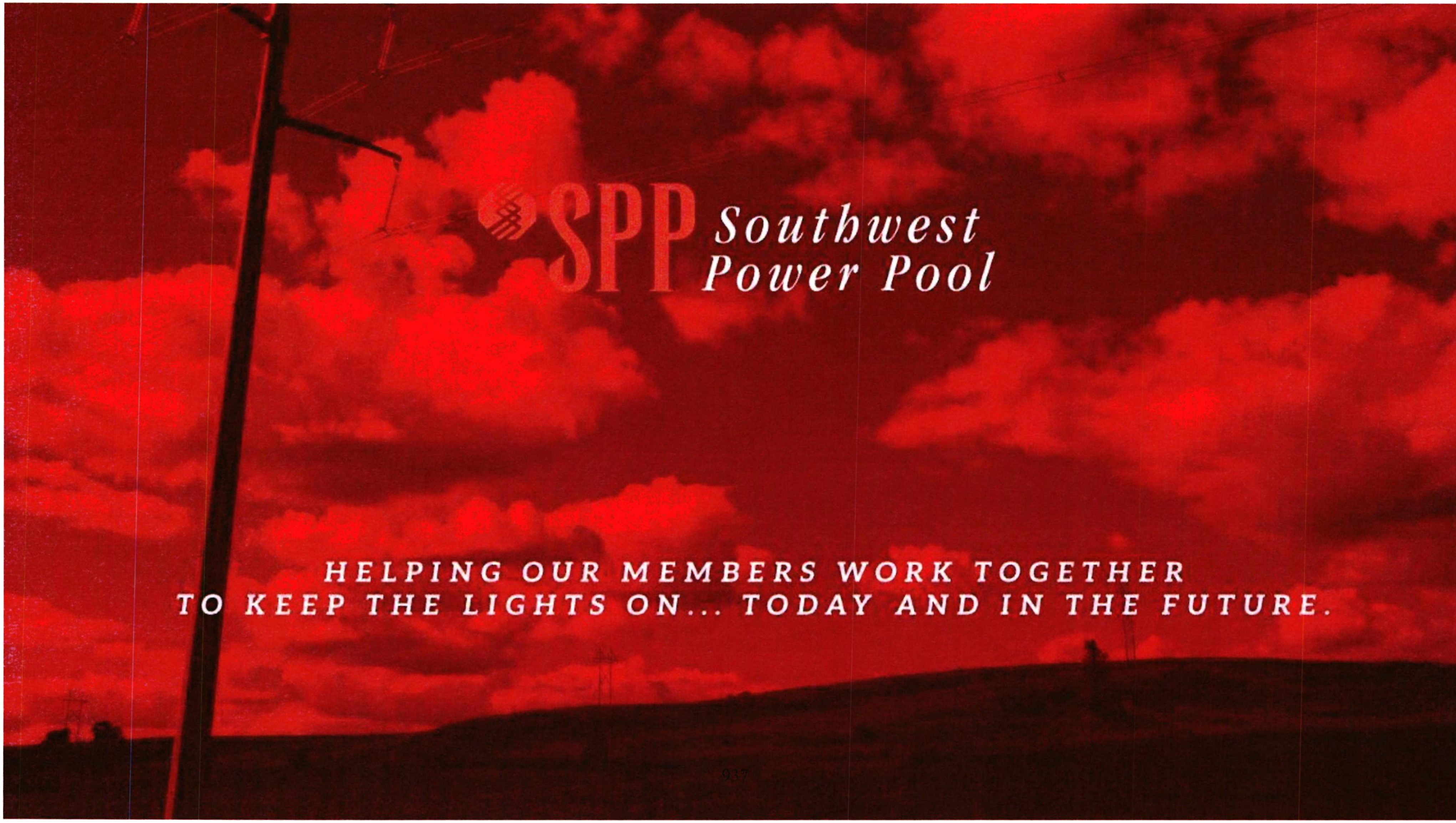
CONCLUSION

The definition of "Monthly Customer's Network Load" in Section 34.4 of the SPP OATT by its own terms does not require the addition of electricity a retail customer produces and consumes on site. A large number of SPP members have for many years properly construed Section 34.4 and based their calculation of their Monthly Network Load on their actual load at the time of the peak, without attempting to add in some estimate of what their retail customers may be self-supplying behind their retail meters. Indeed, it would be impossible to apply an interpretation that required that Network Customers must somehow look behind every residential, commercial, and industrial customer's meter to see if they were generating any of their own electricity and, if so, how much, at the time of the Network Customers' monthly peak. Given that Section 34.4. contains no distinctions on size, that is the only other possible interpretation. FERC has confirmed that MISO's identical provision does not include electricity that is self-supplied by Qualifying Facilities. Further, FERC Order Nos. 888, 888-A, and 890 addressed the treatment of Wholesale BTM Generation, and the record in those dockets demonstrates that electricity self-supplied on site by retail customers was not included. Finally, as to Qualifying Facilities, allocating costs as

[28] FERC Order No. 888 at 296.

if they were taking standby service at the time of monthly peaks would violate federal and state PURPA regulations.

Electricity that is self-supplied by rooftop solar, Qualifying Facilities or other generation behind a retail meter is not a part of a Network Customer's Network Load under Section 34.4 of the SPP OATT.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TO KEEP THE LIGHTS ON... TODAY AND IN THE FUTURE.
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SPP Southwest Power Pool

Network Load Reporting

March 28, 2018

Purpose of Presentation

- Review of current requirements for reporting of Network Load
  - Focus on Behind-the-Meter Generation (BTMG) requirements

- Discussion of results from the survey of Network Load reporting in SPP

Tariff Provisions

4

FERC Pro Forma Definition of Network Load

The load that a Network Customer designates for Network Integration Transmission Service under Part III of the Tariff. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Part II of the Tariff for any Point-To-Point Transmission Service that may be necessary for such non-designated load.

SPP Tariff Definition of Network Load

The load that a Network Customer designates for Network Integration Transmission Service under Part III of the Tariff. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Part II of the Tariff for any Point-To-Point Transmission Service that may be necessary for such non-designated load.

6

SPP Tariff Definition of Resident Load for Schedule 11 Billing - Section 41(b) only

(b) Transmission Owners providing transmission service to: (i) bundled retail load for which such Transmission Owners are not taking Network Integration Transmission Service or Firm Point-To-Point Transmission Service under the Tariff; and (ii) load being served under Grandfathered Agreements for which such Transmission Owners are not taking Network Integration Transmission Service or Firm Point-To-Point Transmission Service under the Tariff. . .

SPP

Losses in Network Service Load - SPP Tariff Attachment M, Sec. II(a)

The Network Customer shall be responsible for real power losses associated with Network Integration Transmission Service to its Network Load for each Zone in which its Network Load is located for the purposes of determining charges under Schedule 9 and Schedule 11 to this Tariff. The Network Customer's loss responsibility . . . shall be included when calculating that Network Customer's Load Ratio Share, Base Plan Zonal Load Ratio Share and Region-wide Load Ratio Share.

FERC Orders

9

FERC Order in FMPA v. FP&L - Docket Nos. TX93-4 & EL93-51

Page 23: FMPA argues that Florida Power's local resources should be treated differently because all are connected to the grid, while FMPA's generating units can meet local loads without first entering the Florida Power grid. This is not a meaningful distinction. . . If FMPA has a load and resource that it does not want to integrate, it can isolate the load and resource from Florida Power's transmission system and eliminate it from the request for full integration

SPP

Order 888

Page 297: . . . if a customer wishes to exclude a particular load at discrete points of delivery from its load ratio share of the allocated cost of the transmission provider's integrated system, it may do so. Customers that elect to do so, however, must seek alternative transmission service for any such load that has not been designated as network load for network service. This option is also available to customers with load served by "behind the meter" generation that seek to eliminate the load from their network load ratio calculation.

Order 888-A

Page 245:. . . the Commission will allow a network customer to exclude the entirety of a discrete load from network load, but not just a portion of the load served by generation behind the meter.

Page 247: Quite simply, a load at a discrete point of delivery cannot be partially integrated – it is either fully integrated or not integrated.

Order in Occidental Complaint against PJM - Docket No. EL02-121

PJM's practice of adding back the amount of load reduction during curtailment was rejected by FERC:

¶ 27: . . . the Commission found that PJM's practice of adding back curtailed load to its calculation appeared inconsistent with the underlying rationale of reducing a customer's costs when it reduces load during system peaks. The October 10 Order further noted that relying on curtailed loads to allocate PJM's access charge costs may create a disincentive for load serving entities (LSEs) to implement load response programs on their own systems, since LSEs would be charged for system costs regardless of whether they curtail load during system peaks.

Order 890

- ¶ 1619: The Commission is not persuaded to require transmission providers to allow netting of behind the meter generation against transmission service charges to the extent customers do not rely on the transmission system to meet their energy needs . . . We believe it is most appropriate to continue to review alternative transmission provider proposals for behind the meter generation treatment on a case-by-case basis, as the Commission did in the PJM proceeding cited by the commenters.

Order 890-A

¶ 965: The Commission declined to require transmission providers to allow netting of behind the meter generation against transmission service charges to the extent customers do not rely on the transmission system to meet their energy needs, stating that commenters had not provided any different arguments not fully addressed in Order No. 888. . . The Commission concluded it is most appropriate to continue to review alternative transmission provider proposals for behind the meter generation treatment on a case-by-case basis.

Order 890-B

¶ 216: In Order No. 890-A, the Commission reiterated that the pro forma OATT permits transmission customers to exclude the entirety of a discrete load from network service and serve such load with the customer's behind the meter generation and through any needed point-to-point service, thereby reducing the network customer's load ratio share. In other situations, use of point-to-point service by network customers is in addition to network service and, therefore, does not serve to reduce their network load . . .

SPP

Order in Ameren Complaint against Prairieland – Docket No. EL09-69

¶ 27: Prairieland failed to comply with the Tariff by not designating its total load as Network Load . . . Prairieland had the responsibility under its Service Agreement and the Tariff to designate the necessary behind-the-meter generation when taking Network Service. As the Commission has explained in Order Nos. 888 and 890, the responsibility for load served by behind-the-meter generation is with the transmission customer

Summary of Network Load Reporting Requirements

For network service at a discrete delivery point, SPP understands FERC's general policy as requiring all actual load to be reported

Since only actual load is to be counted, there should be no add-back of load that has been reduced by utility curtailment or interruption

The load is to reflect adjustment for losses across the transmission system in accordance with the SPP Tariff