- Transmission and Distribution Utility Metering System Services ("MET"); and
- Transmission and Distribution Utility Customer Service ("TDCS") – this function includes the costs historically included in the Transmission and Distribution Utility Billing System Services ("TBILL") function and the Transmission and Distribution Utility Customer Services ("TDCS") functions.

These functions are based on the requirements of 16 Tex. Admin. Code ("TAC") § 25.344 and the instructions included in the Commission's *Transmission & Distribution (TDU) Investor-Owned Utilities Rate Filing Package for Cost of Service Determination.*

2. Classification

The second step refines the functionalization process by further subdividing the accounts into how the costs were incurred (*i.e.,* are the costs energy-related, demand-related, customer-related, revenue-related, or a combination thereof). Fixed costs were generally classified as demand-related or customer-related, and variable costs were classified as energy-related or revenue-related.

3. Allocation Factors

The third step in the allocation process involves developing allocation factors for each rate class for each of the classification factors described above, for each of the four functions. These factors take into account the characteristics of each rate class. The allocation factors developed by the Company to support the cost allocation process are described as follows:

(a) Two separate Customer factors were developed using: (i) the number of customers in each rate class at the end of the test year, weighted for meter investment; and (ii) the number of customers in each rate class at the end of the test year;

(b) Demand factors were developed using rate class demands and the appropriate cost allocation method (*e.g.,* 4-Coincident Peak, Non-Coincident Peak);

(c) Energy factors were developed based on the energy usage of each rate class;

(d) Revenue factors were developed based on the percentage of revenues received from each rate class; and

(e) Factors for General Plant (Accounts 389-399) were derived on the basis of allocated operating plant.

As discussed above, all allocation factors are shown in Schedule II-I-2. Allocation factors are developed so that various rate classes are exempted from certain costs as appropriate. For example:

- Wholesale rate classes do not share in costs that apply only to retail rate classes, including, but not limited to, Account 565 Transmission of Electricity by Others, and Account 587 Customer Installation Expense;
- Rate classes taking Primary voltage service do not share in costs that apply only to Secondary service;
- Rate classes taking Transmission voltage service, or Primary voltage service at or within one span of a substation, do not share in most costs that apply only to service beyond substations;
- The Transmission rate class does not share in costs related to substation transformation; and
- Costs that apply only to Lighting Service are directly assigned to the Lighting Class.

4. Allocation

The fourth and final step in the Rate Class Cost of Service Study allocation process is the actual allocation of all rate base and expense items to the rate classes, using the factors developed in the third step as described above. The Company proposes to allocate costs to the following

rate classes:

(1) Residential Service;
(2) Secondary Service Less Than or Equal to 10 kW;
(3) Secondary Service Greater Than 10 kW;
(4) Primary Service Less Than or Equal to 10 kW;
(5) Primary Service Greater Than 10 kW – Distribution Line;
(6) Primary Service Greater Than 10 kW – Substation;
(7) Transmission Service;
(8) Lighting Service;
(9) Wholesale Substation Service – XFMR; and
(10) Wholesale Distribution Line Service.

These are the same rate classes that were approved in Docket Nos. 35717, 38929, and 46957, and are included in Oncor's current Tariff for Retail Delivery Service and Tariff for Transmission Service.

The summation of all of the allocations for each rate class yields the cost to serve each rate class, including a return on investment in rate base for each rate class. From this information, a revenue requirement, a rate of return, and unit costs can be determined for use in the rate design process. The proposed rate classes and the rate design process are described in more detail later in my direct testimony.

C. Demand Allocation Methodology – Distribution Costs

Q. PLEASE DESCRIBE THE DEMAND ALLOCATION METHODOLOGY THAT YOU USED IN THE COST OF SERVICE STUDY FOR THE COMPANY'S DEMAND-RELATED DISTRIBUTION COSTS.

A. The demand allocation methodology used for the demand-related distribution costs in the Rate Class Cost of Service Study is based on the Non-Coincident Peak ("NCP") demand of each rate class occurring during the test year. The rate class NCP demand is the highest 15-minute aggregated demand for all the members of a given rate class. The individual rate class NCPs may or may not occur during the same period. For example, the greatest 15-minute demand for the Residential Rate Class and the Secondary Service Less Than or Equal to 10 kW Rate Class may

be the same period, but the NCP for the Lighting Rate Class will most likely occur at some other time. The NCP demands for the test-year are shown on Workpaper II-I-2.2.[1]

Q. WHY HAVE YOU SELECTED A NCP DEMAND METHODOLOGY FOR DEMAND-RELATED DISTRIBUTION COSTS?

A. The Company must plan and construct its distribution system to serve the maximum load requirement of each individual retail and wholesale customer. As a result, the Company's investment in the distribution plant needed to serve each customer does not depend on the month or the time of day when such loads occur. The Company's distribution plant must be capable of delivering this maximum load whenever it is demanded by the customer. Of course, when the loads of individual customers are aggregated into a small number of rate classes, the Company and those customers benefit from the diversity of the constituent customers' individual loads. A NCP demand allocation method captures the cost causation associated with the maximum load of each rate class on the Company's distribution system. As such, this method best recognizes the contribution of each rate class to the annual cost of the distribution system.

Q. IS A NCP METHODOLOGY THE MOST APPROPRIATE METHOD FOR ALLOCATING DEMAND-RELATED DISTRIBUTION COSTS?

A. Yes. As I have explained, a major objective of a cost allocation method is to reasonably and equitably share the benefits of diversity among the various rate classes. Additionally, the method selected should be clear and understandable, should not require an unreasonable amount of input data, and should offer a reasonable degree of stability from year to year. The NCP method proposed by the Company for demand-related distribution costs satisfies these criteria and was approved by the Commission in all of Oncor's unbundled base rate cases – Docket Nos. 22350, 35717, 38929,

[1] The associated allocation factors are shown on the following Schedules: II-I-1-DIST; II-I-2-DIST; II-I-1-MET; II-I-2-MET; II-I-1-TDCS; and II-I-2-TDCS.

and 46957. It is the most equitable and reasonable approach for the Company for the following reasons: (1) it recognizes the maximum usage of each rate class during the year; (2) it is less susceptible to shifts in cost responsibility from year to year compared to other allocation methods (*e.g.*, coincident peak, average and peak, energy) and, thus, provides more stable results; and (3) it yields simple, easy-to-calculate factors that are suitable for the allocation of all types of demand-related distribution costs. Because this method encompasses all of these important concepts of cost allocation, it is the most reasonable method for the Company to utilize in designing both Retail and Wholesale Delivery Service rates.

Q. ARE ANY DIST FUNCTION COSTS ALLOCATED USING A DEMAND ALLOCATION METHODOLOGY OTHER THAN THE NCP METHODOLOGY DESCRIBED ABOVE?

A. Yes. The costs recorded in Account 565, Transmission of Electricity by Others, are allocated on the basis of Oncor's average 4CP for retail loads that are coincident to the ERCOT peak loads in the months of June – September, as prescribed by 16 TAC § 25.192.

Q. HOW WERE THE DEMAND DATA USED IN THE COST ALLOCATION PROCESSES DEVELOPED?

A. Rate class demand data were developed in conjunction with the Company's continuing program of load research, as described in the direct testimony of Company witness Mr. Darryl E. Nelson.

D. Adjustments to Rate Class Revenue Requirements

Q. HAVE YOU MADE ANY ADJUSTMENTS TO THE RATE CLASS REVENUE REQUIREMENTS CALCULATED IN THE RATE CLASS COST OF SERVICE STUDY?

A. Yes. I have made adjustments to the revenue requirements for the various retail rate classes to: (1) allocate the adjustment to Other Revenue resulting from power factor billing as a credit to the retail rate classes; (2) allocate discretionary service charge revenue as a credit to the retail rate classes;

and (3) allocate miscellaneous revenue and forfeited discounts as a credit to the retail and wholesale rate classes. These adjustments are described below.

Q. HOW DID YOU ALLOCATE THE COMPANY'S ADJUSTMENT TO OTHER REVENUE RESULTING FROM POWER FACTOR BILLING?

A. As shown on Schedule II-I-2.1f, I allocated the proposed power factor revenue credit of $17,616,778 to all retail rate classes, on the basis of Total Distribution Plant – Net, Excluding the Wholesale Rate Classes.

Q. IN THE DESIGN OF RETAIL DELIVERY SERVICE RATES, HOW DID YOU ALLOCATE THE REVENUE RESULTING FROM DISCRETIONARY SERVICE CHARGES AND FROM OTHER REVENUES?

A. As shown on Schedule II-I-2.1f, I allocated the Discretionary Revenue as a credit of $22,468,503 as follows:

(1) $17,168,858 from the DIST function and $205,015 from the TDCS function to all retail rate classes, on the basis of test year-end customer count; and

(2) $5,094,631 from the MET function to all retail rate classes, on the basis of test year-end customer count weighted by meter investment.

As shown on Schedule II-I-2.1f, I allocated $456,565 of Miscellaneous Service Revenues-Other and $6,086,808 of Other Electric Revenues to all rate classes on the basis of net distribution plant.

As shown on Schedule II-I-2.1f, I allocated $9,358,267 of Rent from Property as a series of credits as follows:

(1) $8,281,656 from Pole Contacts and $127,189 from Fiber Optics-Overhead allocated on the same basis as Account 364, Poles, Towers, and Fixtures;

(2) $932,722 from Fiber Optics-Underground allocated on the same basis as Account 366, Underground Conduit; and

(3) $16,700 from Third-Party Rentals allocated on the same basis as general plant; and

I also allocated $1,070,706 of Forfeited Discounts to all retail rate classes based on the retail class cost of service revenue requirement, excluding Account 565 (Transmission of Electricity by Others), as shown on Schedule II-I-2.1f.

E. Rider DCRF

Q. IS THE COMPANY PROPOSING ANY CHANGES TO ITS RIDER DISTRIBUTION COST RECOVERY FACTOR ("DCRF")?

A. The only substantive change to Rider DCRF proposed by the Company is to transfer the distribution plant assets, and their associated revenue requirement, to the base rate recovery of the affected rate classes pursuant to 16 TAC § 25.243, as described in the direct testimony of Oncor witness Mr. W. Alan Ledbetter. Oncor is not proposing any changes to the structure of Rider DCRF; however, the rates will be set to zero to reflect the results of this proceeding.

Q. DOES THE COMPANY HAVE A DCRF PROCEEDING CURRENTLY PENDING?

A. No. The Company's last DCRF filing was made on April 8, 2021 in Docket No. 51996. The Commission entered an order in the case on July 30, 2021, and the approved rates went into effect, per 16 TAC § 25.243(e)(6)(C), on September 1, 2021.

F. Allocation of Costs to the Wholesale Rate Classes

Q. WHAT IS THE COST BASIS FOR THE WHOLESALE RATES THAT YOU ARE PROPOSING?

A. I am proposing wholesale rates that are based on the same system average cost methodology that is used to develop the Company's retail rates.

V. TARIFF FOR RETAIL DELIVERY SERVICE

A. Rate Structure

Q. WHAT ARE THE BASIC PRINCIPLES UNDERLYING THE COMPANY'S PROPOSED DELIVERY SERVICE RATE STRUCTURES?

A. The proposed rates are designed to: (1) reflect the cost of service; (2) be

equitable to customers within a given rate class; (3) rely on billing units that are easy to calculate and explain; and (4) comply with the requirements of the Public Utility Regulatory Act ("PURA") and the associated Commission Substantive Rules.

Q. HOW WAS THE RATE CLASS COST OF SERVICE USED IN FORMULATING THE PROPOSED DELIVERY SERVICE RATES?

A. The cost of providing service is generally considered one of the most important factors in determining a proper rate design. The Rate Class Cost of Service Study was used as a guide in determining the individual component charges contained in the proposed rates for Retail Delivery Service, such as the meter charge, customer charge, and distribution system charge. Basing the proposed rate structure on the functionalized rate class cost of service also results in a small degree of revenue stability. Because a large portion of the Company's Delivery Service costs are fixed and are incurred rather uniformly throughout the year, it is desirable to have a rate structure that is not unreasonably sensitive to changes in economic and weather conditions. Basing rates on the Company's functionalized rate class cost of service is a beginning step for the Company to receive revenue from the customers' Retail Electric Providers ("REPs") in a manner similar to how Oncor incurs costs to serve customers. However, the actual rate design advances these concepts even further.

Q. PLEASE EXPLAIN HOW THE PROPOSED DELIVERY SERVICE RATES ARE EQUITABLE TO A REP'S CUSTOMERS WITHIN A GIVEN RATE CLASS.

A. While the Rate Class Cost of Service Study provides the primary input to the rate design process, it is also important in designing rates to ensure that customers on the same rate, but with different load characteristics, are charged according to their responsibility for costs. The Company's Delivery Service rates utilize fixed charges for the essentially fixed costs related to metering and customer service, while utilizing fixed, variable demand-

based, and/or energy-based charges to recover that portion of the cost responsibility that is directly related to the utilization of the Company's transmission and distribution facilities, based on the customer's metered load. For demand-metered rate classes, the design of the distribution system charges either includes a minimum demand provision – a "ratchet" – that provides for the recovery of distribution costs, incurred on an annual basis, through monthly billing, or a demand charge applied to actual monthly demands. By utilizing these means of cost recovery, the Company's proposed rates assure intra-class equity.

B. Rate Design

Q. WHAT RATES ARE YOU PROPOSING IN THIS PROCEEDING?

A. As stated above, the Company is proposing rates for the retail rate classes and two wholesale rate classes, all of which were approved in Docket Nos. 35717, 38929 and 46957. The eight Retail Delivery Service rates are:

- Residential;
- Secondary Service Less Than or Equal to 10 kW;
- Secondary Service Greater Than 10 kW;
- Primary Service Less Than or Equal to 10 kW;
- Primary Service Greater Than 10 kW – Distribution Line;
- Primary Service Greater Than 10 kW – Substation;
- Transmission Service; and
- Lighting Service.

The two Wholesale Rates are:

- Rate XFMR – Wholesale Substation Service; and
- Rate DLS – Wholesale Distribution Line Service.

Q. PLEASE EXPLAIN THE BASIC STRUCTURE OF THE PROPOSED RATES.

A. The Company is proposing four basic types of rate structures. For residential customers and for secondary and primary voltage customers

with demand less than or equal to 10 kW, the Company is proposing a rate structure that has the following components:

- Customer Charge ($/customer);
- Metering Charge ($/customer);
- Distribution System Charge ($/kWh);
- Nuclear Decommissioning Charge ("NDC") ($/kWh);
- Transmission Cost Recovery Factor charge ("TCRF") ($/kWh);
- Distribution Cost Recovery Factor charge ("DCRF") ($/kWh);
- Competitive Meter Credit[a] ("CMC") ($/month); and
- Energy Efficiency Cost Recovery Factor charge ("EECRF") ($/kWh).

a – If applicable

For secondary and primary voltage customers with demand greater than 10 kW, and for customers in the transmission service rate class, the Company is proposing a rate structure with the following components:

- Customer Charge ($/customer);
- Metering Charge ($/customer);
- Transmission System Charge ($/kW);
- Distribution System Charge ($/kW);
- NDC ($/kW);
- TCRF charge ($/kW);
- DCRF charge ($/kW);
- CMC charge[a] ($/month); and
- EECRF charge[a] ($/kWh).

a – If applicable.

For the lighting rate class, the Company is proposing a rate structure with the following components:

- Customer Charge[a] ($/premise);
- Metering Charge[a] ($/premise);
- Facilities Charge – for unmetered service ($/luminaire);
- Distribution System Charge – for metered service ($/kWh);
- NDC ($/kWh);
- DCRF charge ($/kWh);
- CMC charge[b] ($/month); and
- EECRF charge[b] ($/kWh).

a – This charge is not included for Unmetered Lighting Service, which has a Point-of-Delivery Charge and a Facilities Charge per luminaire.

b – If applicable.

For the two wholesale rate classes, the Company is proposing a rate structure with the following components:

- Customer Charge ($/Point of Interconnection);
- Metering Charge ($/Point of Interconnection); and
- Distribution System Charge ($/kW).

Q. PLEASE EXPLAIN THE BASIS FOR THE CUSTOMER CHARGE.

A. The customer charge is a charge designed to recover: (1) the costs associated with rendering a bill for Delivery Services; and (2) the costs associated with customer service, including the personnel and systems necessary to handle inquiries from the REPs, customers, and those entities that request line extensions and other discretionary services. The costs that make up the customer charge are functionalized to the TDCS function.

Q. PLEASE EXPLAIN THE BASIS FOR THE METERING CHARGE.

A. The metering charge is a charge designed to recover the costs associated with the Company's meters and meter related activities. The costs that make up the metering charge are functionalized to the MET function.

Q. PLEASE EXPLAIN WHY YOU HAVE REMOVED THE TRANSMISSION SYSTEM CHARGE FOR EACH APPLICABLE RETAIL RATE CLASS.

A. The costs associated with the ERCOT system-wide transmission access fee paid by all Distribution Service Providers are currently recovered through the charges implemented under Rider Transmission Cost Recovery Factor ("TCRF").[2] In fact, the Transmission Service Charge for Oncor has been set at $0.00[3] for over a decade. Additionally, all ERCOT TDUs now recover these costs through the TCRF, and no ERCOT TDU has a Transmission Service Charge as a base rate. Therefore, I have removed the Transmission Service Charge from the applicable rate schedules and

[2] Approved in *Petition of Oncor Electric Delivery Company LLC to Update Its Transmission Cost Recovery Factor*, Docket No. 52898 (February 1, 2022).
[3] *Application of Oncor Electric Delivery Company LLC for Authority to Change Rates*, Docket No. 38929, Finding of Fact No. #39 (August 26, 2011).

have retitled them accordingly. This cost recovery method is set forth in 16 TAC § 25.193. The development of the TCRF charges for each retail rate class is described below in the discussion of that rider.

Q. PLEASE EXPLAIN THE DISTRIBUTION SYSTEM CHARGE ("DSC") APPLIED TO RETAIL RATE CLASSES.

A. The DSC is a charge designed to recover the costs associated with distribution system service, as that term is defined in 16 TAC § 25.341. This charge is based on the costs that are functionalized to the DIST function, for all rate classes.

Q. PLEASE EXPLAIN THE DSC APPLIED TO WHOLESALE RATE CLASSES.

A. The methodology used to calculate the DSC applicable to the wholesale rates classes is essentially the same as used to calculate the DSC for the retail rate classes. The only distribution service costs not allocated to the wholesale rate classes are Miscellaneous Service Revenues – Discretionary and Customer Installation Expenses because wholesale customers are not responsible for the amounts in these accounts.

Q. PLEASE EXPLAIN THE NUCLEAR DECOMMISSIONING CHARGE ("NDC") APPLIED TO RETAIL RATE CLASSES.

A. PURA § 39.205 provides that any remaining costs associated with nuclear decommissioning obligations continue to be subject to cost of service rate regulation and shall be included as a non-bypassable charge to retail customers. Pursuant to 16 TAC § 25.303, nuclear decommissioning costs need not be reviewed in a general rate proceeding.

Q. ARE YOU PROPOSING ANY CHANGES TO THE NDC RATES?

A. Yes. While I am not proposing any changes to the NDC revenue requirement, I am proposing changes to the NDC rates, as they will be calculated using the updated rate class cost allocation factors and billing units that are presented in this case. Those allocation factors and the ultimate billing units will be used to recover the NDC revenue requirement

set by the Commission in Docket No. 50945, *Application of Comanche Peak Power Company LLC For Review Of Nuclear Decommissioning Cost Study And Funding Analysis Under 16 TAC § 25.303(f)(2).*

Q. ARE YOU PROPOSING ANY ADDITIONAL CHANGES TO THE NDC?

A. Yes. I am also proposing that the NDC be made applicable to all end-use retail customers in Oncor's service territory. To date, the NDC has not been applicable to some customers. Most notably, the customers who were previously served by TXU SESCO. Southwestern Electric Service Company ("SESCO") was acquired by TXU (now Oncor) in 1993 and prior to the acquisition, SESCO was a Distribution only utility, meaning it had no generation facilities. Due to the fact that pre-deregulation, TXU SESCO purchased power to meet its energy needs, unlike the rest of TXU (now Oncor) that was served by Company-owned generation, which included nuclear generation units previously owned by Oncor's former corporate parent. Given that the industry transitioned to deregulation and competition approximately 20 years ago, it is appropriate for the TXU SESCO distinction to expire. The uniform application of Rider NDC to all end-use customers served by Oncor will also eliminate confusion among end-use customers and REPs, thereby reducing billing errors and lowering administrative costs incurred by Oncor and the REPs.

Q. WHAT IS THE PURPOSE OF THE TCRF CHARGE APPLIED TO RETAIL RATE CLASSES?

A. As specified in 16 TAC § 25.193, the TCRF charge permits the Company to recover the cost of network transmission rates approved or allowed by the Commission to the extent that such rates vary from the transmission service rate utilized to determine the charges of the distribution service provider. Because the transmission service charge for each retail rate has been set to $0.00, 100% of the ERCOT transmission access fees are included in the calculations of the TCRFs for each rate class, in accordance with the provisions of 16 TAC § 25.193.

As shown in my Exhibit MAT-2, the ERCOT transmission access fee of $64.441565217 per total ERCOT 4CP kW is the sum of the transmission access fees for each of the ERCOT Transmission Service Providers ("TSPs") and includes Oncor's NTS Rate of $17.549284119 and Oncor NTU's WTS Rate of $2.386843198 per total ERCOT 4CP kW proposed by the Company in this proceeding. The development of the Company's proposed NTS rate and the basis for the average ERCOT 4CP load are described below. The transmission-related revenue requirement for retail delivery service is determined in a two-step process. In step 1, the total ERCOT transmission access fee (see above) is multiplied by the average Oncor 4CP load of 25,945,084.560 kW[4] for June - September 2021, and the result is an annual gross transmission expense of $1,671,941,859. In step 2, the current net cost (credit) for transmission expense riders and credit riders of ($19,419,838) is calculated. The sum of these two values is the Company's Total Transmission Expense of $1,652,522,021, as shown on my Exhibit MAT-2. This TCRF revenue requirement is then divided by two (because the TCRFs are calculated semi-annually based on 50% of the total annual transmission expense), and this value is subsequently allocated to the various retail rate classes by using the unadjusted rate class average 4CP demands for the test year, as shown on my Schedule IV-J-7 to determine the TCRF revenue requirement for each rate class. Dividing this value by the rate class billing units for the period of March – August 2021 produces the proposed rate class TCRFs.

Q. HOW WILL THE TCRF CHARGE BE AFFECTED BY THE OUTCOME OF THIS PROCEEDING?

A. As stated above, all of the costs associated with the current ERCOT

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[4] As reported in Attachment A to ERCOT's Report on the 2021 "4CP" Coincident Peak Load in the ERCOT Region in Docket No. 52989, *Commission Staff's Petition to Set 2022 Wholesale Transmission Service Charges for the Electric Reliability Council of Texas,* dated December 21, 2021.

system-wide transmission access fee are included in the calculation of the TCRF charge for each rate class. Any subsequent changes to ERCOT TSP rates (*i.e.*, any change to the current access fees shown in my Exhibit MAT-2), and any unreconciled "adjustment amount" calculated in accordance with 16 TAC § 25.193(b)(2)(B) (*i.e.*, the "ADJ" term in the formula for the TCRF Revenue Requirement), will be included in the calculation of the TCRF charge to be included in the compliance tariff filing associated with this proceeding. In addition, the allocation factors used to allocate the TCRF revenue requirement to the rate classes will be updated (if necessary) to reflect the final values as determined in this proceeding, and the rate class billing determinants used to develop the compliance tariff will be updated to use data from the latest available six-month period specified in 16 TAC § 25.193(c) if the effective date of the compliance tariff is after September 1, 2022.

Q. PLEASE EXPLAIN THE BASIS FOR THE AVERAGE 4CP LOADS USED IN THE CALCULATION OF ONCOR'S TCRF REVENUE REQUIREMENT AND THE DEVELOPMENT OF THE RATE CLASS TCRFs.

A. The Company used the unadjusted average value of the ERCOT peak load for the months of June – September 2021 (*i.e.*, the ERCOT 4CP load), as developed in Docket No. 52989, *Commission Staff's Petition to Set 2022 Wholesale Transmission Service Charges for the Electric Reliability Council of Texas, Inc.*,[5] to determine Oncor's TCRF Revenue Requirement and in the development of rate class TCRFs. As described above, Oncor's 4CP kW value is 25,945,084.560 kW, which is approximately 36% of the total ERCOT 4CP.

Q. PLEASE EXPLAIN RIDER EECRF – ENERGY EFFICIENCY COST RECOVERY FACTOR THAT IS APPLIED TO RETAIL RATE CLASSES.

A. PURA § 39.905 and 16 TAC § 25.181 allow utilities to recover the costs of

[5] *Id.*

energy efficiency programs in a timely manner through a cost recovery factor, which the Company designates as Rider EECRF.

Q. HOW DO THE RECOVERY FACTORS REFLECTED IN THE RIDER EECRF IN THIS PROCEEDING COMPARE TO THE RECOVERY FACTORS CONTAINED IN ONCOR'S MOST RECENT EECRF FILING, DOCKET NO. 52178?

A. The EECRFs proposed in this case are identical to those approved in Docket No. 52178 for 2022. The compliance tariff filed after a final order is rendered in this proceeding will include the Company's most recently approved EECRFs.

Q. PLEASE EXPLAIN RIDER RCE – RATE CASE EXPENSE SURCHARGE APPLIED TO RETAIL RATE CLASSES AND RIDER WRCE – WHOLESALE RATE CASE EXPENSE SURCHARGE.

A. These Riders permit the Company to recover the rate case expenses prudently incurred by the Company in this proceeding and approved by the Commission in this proceeding (or in a separate docket), on a rate class basis. The Company anticipates the implementation of these two rate case expense riders to allow for the recovery of rate case expenses from this proceeding. A Pro forma version of Rider RCE and Rider WRCE are included in the Tariff for Retail Delivery Service and the Tariff for Transmission Service, respectively.

Q. PLEASE DESCRIBE THE PROPOSED UNMETERED FACILITIES CHARGE UNDER THE LIGHTING SERVICE RATE.

A. For unmetered service, the facilities charge is designed to recover the cost of the light fixture and pole, if provided by the Company (in accordance with the lighting schedule option under which service is provided), and the cost of the distribution system used to deliver the power to the lights. In addition, the on-going operation and maintenance ("O&M") cost of the distribution and lighting facilities is included in the facilities charge.

Q. PLEASE DESCRIBE THE PROPOSED DSC FOR METERED FACILITIES

UNDER THE LIGHTING SERVICE RATE.

A. For the metered service options, the cost of the distribution system and the associated O&M costs for Company-owned facilities are included in the DSC.

Q. IS THE COMPANY PROPOSING TO CONTINUE TO PROVIDE OUTDOOR LIGHTING SERVICE TO ITS EXISTING OUTDOOR LIGHTING CUSTOMERS?

A. Yes. However the rate will remain closed to new installations because this service is considered a competitive energy service, except for "grandfathered" installations that existed at the time of deregulation/unbundling.

1. Billing Demand for Certain Utility Customers

Q. DOES THE COMMISSION HAVE A RULE THAT GOVERNS DEMAND RATCHETS FOR THE SECONDARY SERVICE GREATER THAN 10 KW RATE CLASS?

A. Yes. 16 TAC § 25.244(c) states that if a demand ratchet is utilized, the demand ratchet shall not apply to a nonresidential secondary voltage service customer that has an annual load factor less than or equal to 25 percent.

Q. PLEASE DESCRIBE HOW THE DEMAND CHARGES FOR LOW LOAD FACTOR LOADS SERVED UNDER THE SECONDARY SERVICE GREATER THAN 10 kW RATE ARE CURRENTLY DETERMINED.

A. The DSC for customers with loads that are greater than 20 kW and have an annual load factor of less than or equal to 25 percent is based on their actual monthly demand and the load factor group ("LF Group") associated with their historical load factor for the most recent calendar year. The demand charge for each LF Group is calculated by dividing the annual revenue produced by each group (as if it were billed using the total demand billing units based on the 80 percent demand ratchet and the proposed DSC applicable to loads with a load factor greater than 25 percent) by the group's

total actual kW for the test year.

The Company reviews each point of delivery greater than 20 kW receiving service under the Secondary Service Greater Than 10 kW rate after the December billing month of each year and determines the annual load factor for each point of delivery. If the point of delivery qualifies for billing under this load factor provision, then a notification is sent to the REP that the rate will be changed for billing under this provision for the January bill cycle. The billing for that point of delivery remains under that revised rate until the next annual review or until a customer change occurs at the premise.

New points of delivery or existing points of delivery with a new tenant (*i.e.,* a different customer) default to the standard rate (*i.e.,* billed on demand with the 80 percent ratchet provision) and remain on that standard rate until the next annual review.

Q. HOW ARE YOU RECOMMENDING THAT THE COMPANY COMPLY WITH 16 TAC § 25.244 IN THIS PROCEEDING?

A. I propose that the Company eliminate the current LF Group methodology and that the DSC for the rate class be a single rate applied to the NCP kW of all customers in the rate class, without any demand ratchets.

Q. DOES 16 TAC § 25.244 REQUIRE THE LF GROUP METHODOLOGY AND DEMAND RATCHETS FOR CUSTOMERS WITH LOAD FACTORS GREATER THAN 25 PERCENT?

A. No, it does not. 16 TAC § 25.244(c) specifically states that the subsection does not require the use of demand ratchets for any customers.

Q. WHY ARE YOU RECOMMENDING TO CHANGE THE CURRENT METHODOLOGY, WHICH WAS PREVIOUSLY APPROVED BY THE COMMISSION?

A. The current LF Group methodology is unique to Oncor. While it is effective, it is confusing for customers and REPs. The LF Group is calculated annually and is in effect for the entirety of the year. The charges associated

with the LF Groups can vary fairly significantly, but the customer is "locked in" for the full year. Additionally, new customers default to a demand ratchet, when it may not be appropriate for them to be charged under one. Therefore, for the sake of equitable treatment for all customers in the rate class, and with the added benefit of being easily understood, applied, and explained by REPs to customers, I believe that my recommendation to have a single DSC that applies to all customers, with no demand ratchets applied to any customer in the rate class, is the appropriate methodology under which to charge the Secondary Service Greater Than 10 kW rate class.

2. Lighting Service Rates

Q. PLEASE DESCRIBE THE TYPES OF SERVICE OFFERED UNDER THE COMPANY'S LIGHTING SERVICE RATES.

A. The Company Lighting Service rate schedule includes Street Lighting Service and Outdoor Lighting Service. Street Lighting Service is offered under a number of Unmetered Facilities rates, a Metered Facilities rate for non-Company owned facilities, or a Metered Facilities rate for Company owned facilities.[6] Outdoor Lighting Service is offered to entities that are currently taking such service but is closed to new installations.

Q. PLEASE DESCRIBE THE RATE DESIGN PROCESS FOR THE COMPANY'S LIGHTING SERVICE RATES.

A. In addition to the general rate design principles described in Sections V.A and V.B above, the rate design process for the lighting class is an iterative process that utilizes the following steps to recover the total Lighting Service revenue requirement:

(1) For service under the Metered Facilities – Non-Company Owned lighting rate, the proposed DSC is associated with the DSC included in the Secondary Service Less Than or Equal to 10 kW rate because the type of distribution service provided by the Company and the cost

[6] Some Unmetered Facilities rates and all Metered Facilities rates for Company-owned lights are closed to new installations.

incurred by the Company to serve the loads are essentially the same in both cases. However, as addressed previously, the billing units for the Secondary Service Less Than or Equal to 10 kW rate class may no longer be the same as the Metered Facilities – Non-Company Owned lighting class, as recommended in this case.

(2) For service under Schedules C and D of the Unmetered Facilities rate, the proposed monthly rates for each light type and wattage are associated with an equivalent DSC for the Secondary Service Less Than or Equal to 10 kW rate. Again, because the type of service and the cost incurred to serve the loads are comparable, the basis for the rates should be comparable as well. As with Metered Facilities – Non-Company Owned, the billing units between the two may no longer be the same, as recommended in this case. The Company proposes to continue serving existing Schedule C lights at the same rate as Schedule D lights of the same type and wattage and proposes to maintain the closure of service under Schedule C to any new installations.

(3) The proposed rate design for the Schedule A LED street lights as well as the Non-LED Schedule A and B street lights served under the Unmetered Facilities rate (including the Historical, Rectangular, Post-Top, and Incandescent lights) is based on the assignment of the functionalized distribution costs allocated to the lighting class that are not otherwise recovered from Outdoor Lighting service, metered service, or service under Schedules C & D of the Unmetered Facilities rate. These costs are categorized as follows: (1) return on rate base, (2) depreciation and amortization, (3) O&M expenses, (4) Administrative and General expenses, and (5) tax-related expenses. This is the same methodology that was used to establish current rates.

(a) For LED lights, the costs identified above are allocated to each

applicable service offering,[7] by light type and wattage, based on: (1) the current installed costs of each service option, (2) the load (monthly kWh) associated with each service option, (3) fixed costs allocated on per-light basis, (4) maintenance-related costs, and (5) taxes and other costs that are based on revenue.

The proposed rates for these lights are calculated by dividing the total costs allocated to each light type and wattage by 12 and then dividing the result by the number of lights served at the end of the test year.

(b) For Non-LED lights, the installed costs of all Schedule A lights and the allocation of maintenance cost will be assigned as the cost as the equivalent LED light.[8] The load-based cost of these lights will also be based on their monthly kWh usage; and the allocation of fixed cost and revenue-based costs will have the same basis as the LED lights described in (a), above.

For Non-LED Schedule B lights, the installed costs will be increased based on the cost difference between the standard wood pole and the steel pole used with Schedule B lights.

Q. WHY IS THE COMPANY PROPOSING TO USE THE INSTALLED COSTS OF LED LIGHTS AND THEIR ALLOCATED MAINTENANCE COSTS TO ESTABLISH THE RATES FOR NON-LED LIGHTS?

A. This proposed methodology recognizes the industry trend of using LED lights for the vast majority of new-build installations. It also recognizes the reality that mercury vapor and metal halide lights are not commercially available, and sodium vapor lights are not expected to be available at some point in the future. Pricing Non-LED lights on the basis of the cost of a

[7] *I.e.,* Schedule A LED Cobra Head, Rectangular, Post-top, and Historical lights served under the Unmetered Facilities rate.

[8] The equivalent LED lights for unmetered Mercury Vapor, Sodium Vapor, and Metal Halide lights are those set forth in the "Mercury Vapor and Metal Halide Fixture Replacement Schedule" shown in the proposed Lighting Service rate schedule. The equivalent LED lights for the unmetered Rectangular, Post Top, and Other lights will be based on their energy consumption compared to that of the available LED lights.

comparable LED light also provides a price incentive to the end-user to migrate toward the use of more environmentally friendly LED lights.

Q. WOULD YOU PLEASE DESCRIBE THE COMPANY'S PROPOSED LED STREET LIGHT RATES?

A. For Company-Owned LEDs, the Company is proposing the same 12 Schedule A LED Street Lighting rates that it currently offers, comprised of (1) five Cobra Head LED Street Lighting options; (2) three options for Rectangular LED Street Lighting; (3) two options for Post-Top LED Street Lighting; and (4) two options for Historical LED Street Lighting.[9] For each of these options, the rates shown in the tariff are based on what I will refer to as a "standard LED installation." For the Cobra Head Option, the standard LED installation is an LED street light mounted on a 35' wooden pole with a cobra head arm and served overhead. For the Rectangular Option, the standard LED installation is a rectangular LED street light mounted on a 25' steel anchor-based pole served underground. For the Post-Top Option, the standard LED installation is a post-top LED street light mounted on a 20' fiberglass pole served underground. For the Historical Option, the standard LED installation is a historical LED street light mounted on an 11' aluminum anchor-based historical pole served underground. However, since all of these LED Street Lighting options typically include the use of steel or ornamental poles (and are sometimes served underground), if the Retail Customer requests any installation configuration other than the standard LED installation, then the Retail Customer will pay the difference in costs, if any, for such non-standard installations.

Q. IS THE COMPANY PROPOSING ANY CHANGES TO THE LIGHTING SERVICE TARIFF TO ADDRESS THE ELIMINATION OF MERCURY VAPOR AND METAL HALIDE LIGHTING IN THE COMMERCIAL

[9] Rectangular, Post-Top, and Historical LED Street Lighting options are not available in all five wattage ranges due to the lack of either commercially available lights or lights that meet the Company's reliability standards in certain ranges.

MARKETPLACE AS WELL AS THE PROJECTED REDUCTION IN THE AVAILABILITY OF SODIUM VAPOR?

A. Yes. While the Company is not proposing any changes to the "Mercury Vapor and Metal Halide Fixture Replacement Schedule" provisions of the Lighting Service rate schedule at this time, I am proposing that language be added to this section of the tariff to grant the Company the ability to change how conversions and new installations are implemented as market conditions warrant. This proposal will give the Company the ability to limit the replacement of all mercury vapor and metal halide lights that fail, solely to a comparable LED light, as market conditions dictate, without the need to seek a later revision to the tariff. This proposed change recognizes the industry trend toward the use of LED lights for new installations. It also recognizes that mercury vapor and metal halide lights are no longer commercially available and that the future availability of sodium vapor lights (or High Pressure Sodium) will be curtailed (and ultimately ended) as light manufacturers opt to close down aging sodium vapor light production lines as they break down rather than investing in new production equipment or expensive repairs.

Q. HAVE YOU PROPOSED ANY CHANGES TO THE LIGHTING SERVICE RATE SCHEDULE TO ADDRESS LAMP STANDARDS AND PERFORMANCE OVER TIME?

A. Yes. All street lights, regardless of lamp or luminaire type, will dim over time and eventually burn out or fail. For this reason, I have added language to the rate schedule that states this fact and likewise states that any listed lumens, watts, and kWh levels are target average levels and may not be representative of any specific light. The Company cannot and does not guarantee that any particular light will be the same as others; nor does it guarantee its performance over time.

Q. ARE THE PROPOSED RATE DESIGN CHANGES MENTIONED ABOVE REFLECTED IN THE RATE DESIGN SCHEDULES?

A. Yes, they are.

C. Retail Discretionary Service Charges

Q. WHAT ARE DISCRETIONARY SERVICES?

A. The definition of discretionary services as set forth in 16 TAC § 25.341 is:

> A service that is related to but not essential to the transmission and distribution of electricity from the point of interconnection of a generation source or third party electric grid facilities to the point of interconnection with the retail customer or other third party facilities.

Q. WHAT RETAIL DISCRETIONARY SERVICES IS THE COMPANY PROPOSING IN THIS PROCEEDING?

A. Oncor is proposing to continue offering all of its existing retail uniform discretionary services and all of its existing Company-specific discretionary service charges. All of the Retail Discretionary Services proposed and their supporting cost justification are included in Schedule IV-J-2.

Q. GIVEN NORMAL ANNUAL ACTIVITY LEVELS, HOW MUCH DISCRETIONARY REVENUE WILL THE PROPOSED RATES PRODUCE?

A. The proposed rates will produce discretionary revenue of $22,468,503. I have provided this amount to Company witness Mr. Ledbetter.

Q. HAS THE COMPANY ADDED ANY NEW DISCRETIONARY SERVICES SINCE THE COMPANY'S LAST RATE CASE?

A. No. It has not.

D. Other Retail Tariff Changes

Q. ARE YOU PROPOSING ANY CHANGES TO THE COMPANY'S TARIFF FOR RETAIL DELIVERY SERVICE?

A. Yes. I am proposing the following changes to the Tariff for Retail Delivery Service:

(a) Limit eligibility for the Primary Substation rate to new loads on the system *(i.e.*, no combining of existing loads currently being served);

(b) Revise the rate availability section of the Secondary Service Greater Than 10 kW Rate and the Primary Service Greater Than 10 kW - Distribution Lines Rates to codify the existing practice regarding the length of time that a customer is required to take service on a rate before being eligible for a different rate;

(c) Revise the Company's Service Regulations to include specific provisions governing the pro-ration of monthly bills and the initial rate code assignment;

(d) Eliminate the following riders from the Company's Tariff for Retail Delivery Service:

- Rider RS – Remand Surcharge;
- Rider CSR – Capital Structure Refund;
- Rider TRF – Tax Refund Factor; and
- Rider ERP – COVID-19 Electricity Relief Program.

(e) Add language that reflects the end of production of analog non-standard meters (no longer commercially available);

(f) Add language to the Lighting Service Rate Schedule that reflects that non-LED lights may cease to be commercially available at any given time with no advance notice;

(g) Add language that allows for any unused standard allowance to be used for other purposes (*i.e.* street lights);

(h) Allow service to Home Owners' Associations ("HOAs") in the Street Lighting Rate Schedules;

(i) Add language that addresses the rate treatment of "tiny homes";

(j) Add language that gives the Company flexibility in allowing for credit card payment processing;

(k) Add language clarifying that the Company never intends to abandon an easement unless explicitly stated for a particular easement, and then takes affirmative action to effectuate the

abandonment;

(l) Revise the language concerning contributions in aid of construction and anticipated load to provide more flexibility and recognize the needs and specific circumstances of customers when evaluating anticipated versus achieved load and/or the number and type of dwelling units/lots;

(m) Add language to the Facilities Extension Agreement in regards to revising contract kW based upon achieved kW in the Non-Utilization Clause;

(n) Add additional language concerning the disclosure of underground facilities;

(o) Add language that addresses unmetered service for cellular pole attachments until a viable pole top meter is developed;

(p) Add language that clarifies the definition of Temporary Delivery Service;

(q) Add additional language that addresses when a Retail Customer requests that the Company relocate its facilities, or when the Retail Customer moves or removes its load and the associated cost responsibility;

(r) Revise the language concerning extensions to multi-family dwellings as well as the definition of multi-family dwelling;

(s) Add clarifying language around security payments in the Transmission/Substation Facility Extension Agreement; and

(t) Add a standardized Agreement For Interconnection Of Distribution Generation Resource to Section 6.3 Agreements and Forms.

Q. PLEASE EXPLAIN WHY YOU ARE PROPOSING TO LIMIT THE APPLICATION OF THE PRIMARY SERVICE GREATER THAN 10 KW – SUBSTATION RATE TO NEW CUSTOMERS.

A. In circumstances where the Company has invested in the distribution

facilities necessary to serve individual loads, a combination of loads would impair the Company's ability to recover the full costs incurred to serve the loads. This scenario creates a de-facto stranded investment and would result in a subsidy of the combined load by the Company's other ratepayers. To prevent this scenario, I propose to limit the eligibility for establishing a new point of delivery taking service under the Primary Service Greater Than 10 kW–Substation Rate in Section 6.1.1.1.6 of the Tariff for Retail Delivery Service.

Q. WHY ARE YOU REVISING RATE SCHEDULES 6.1.1.1.3 SECONDARY SERVICE GREATER THAN 10 KW AND 6.1.1.1.5 PRIMARY SERVICE GREATER THAN 10 KW - DISTRIBUTION LINES TO SPECIFY THAT A CUSTOMER MUST TAKE SERVICE UNDER ONE OF THESE RATES FOR A MINIMUM TIME PERIOD OF SIX MONTHS BEFORE CHANGING TO A DIFFERENT RATE?

A. I am proposing to update these rate schedules to conform to the Company's long-standing business practice of requiring a minimum time period before changing to a different rate class. Codifying this practice within the tariff will eliminate any uncertainty for the retail customer regarding the Company's policy in this regard. The main purposes of this policy are to: (1) reduce the opportunity for the customers to arbitrage the lower fixed costs in the Secondary and Primary Service Less Than or Equal to 10 kW rate, particularly in the non-peak months of October – May; and (2) limit the imposition of administrative expenses on the Company and the other customers in these rate classes.

Q. WHY ARE YOU REVISING THE COMPANY'S TARIFF TO INCLUDE PROVISIONS THAT DESCRIBE THE COMPANY'S POLICY ON BILL PRORATION?

A. I am proposing that the Company amend Section 6.2.3 Additional Delivery Service Information, by adding new 6.2.3.4 Proration. The purpose of this change is to codify in its tariff, the Company's long-standing business

practice regarding proration and to eliminate any uncertainty about bill proration for the retail customers and REPs. Briefly stated, the Company's policy is to prorate bills for fixed charges and demand charges that cover a billing period of less than 28 days or more than 33 days, due to a move-in, move-out, or switch. Rate components billed on energy consumption will not be prorated. The prorated portion of a bill will be calculated by dividing the charge amount by 30 and multiplying the result by the number of days of service in the billing period. Normal bill cycles of less than 28 days or more than 33 days are not prorated.

Q. HAVE YOU ADDED ANY OTHER SECTIONS TO THE ADDITIONAL DELIVERY SERVICE INFORMATION SECTION OF THE TARIFF FOR RETAIL DELIVERY SERVICE?

A. Yes. I have added new Section 6.2.3.5 Initial Rate Code Assignment. This section clarifies that new non-residential premises that do not have existing load data will have their initial rate code assignment based on the appropriate projected load information. This information is also used to ensure that adequate facilities are installed to serve the projected load. The Retail Customer's Rate Code (and corresponding Rate Class) may change once actual load data is available and pursuant to the minimum time period required to be on a specific rate.

Q. WHY ARE YOU PROPOSING TO DELETE THE RIDERS LISTED ABOVE FROM THE TARIFF FOR RETAIL DELIVERY SERVICE?

A. I am proposing to delete Rider RS, Rider CSR, and Rider TRF because all of the applicable expenses and/or credits have been recovered (or credited) and, as a result, these riders are no longer applicable. Additionally, Rider ERP is no longer applicable, and I recommend that it be removed from the Company's tariff.

Q. PLEASE DISCUSS WHY A TARIFF REVISION IS NECESSARY TO ADDRESS ANALOG METERS.

A. Analog meters are increasingly difficult to find and acquire. This means that

if an analog meter could be located, the purchase price would likely be well beyond its actual value. To reflect this fact, I propose amending the language for the Non-Standard Metering Service One-Time Fee in Section 6.1.2.1 Uniform Discretionary Service Charges, of the Tariff for Retail Delivery Service, to reflect that a chosen meter must be commercially available at reasonable prices.

Q. PLEASE DISCUSS THE AVAILABILITY OF NON-LED STREET LIGHTS AND HOW YOU INTEND TO REVISE THE TARIFF.

A. As the industry moves more to LED lighting, the availability of non-LED lighting options continues to decrease. Some manufacturers are no longer producing non-LED lights, while others run limited production lines. As non-LED production equipment breaks-down or becomes otherwise inoperable, it is my understanding that the equipment will be replaced with LED lighting production equipment. As this inevitable reality approaches, the Company's tariff needs to reflect that when non-LED lighting options are no longer commercially available (at reasonable prices), the remaining LED options must be utilized so that the Company may continue to provide service to customers. I have revised Section 6.1.1.1.8, the Lighting Service Rate schedule to reflect this scenario.

Q. WILL THE COMPANY CONTINUE TO INSTALL NON-LED STREET LIGHTS?

A. Yes. Currently, Mercury Vapor and Metal Halide are closed to new installations, but the Company will continue to offer and install sodium vapor street lights at a customer's request. However, LED street lights are now considered the standard street lighting type. This is due to the fact that, as mentioned above, in the near future, sodium vapor street lights may no longer be commercially available, and it would not make sense to install a new sodium vapor street light (as a standard light installation) and then have to remove/replace that street light with a LED street light in the near future when the lamp needs to be replaced but no replacement sodium vapor lamp

is available. This scenario would increase costs for the Company and customers by greatly increasing the amount of work required to install and maintain street lights. Therefore, to keep costs and rates down for the benefit of all street light ratepayers, LED street lights are now considered the standard street light installation, and Non-LED lighting options are only installed if specifically requested by a customer.

Q. PLEASE DISCUSS YOUR PROPOSED TARIFF CHANGE CONCERNING UNUSED STANDARD ALLOWANCES.

A. I have modified the language in Sections 6.1.2.2.6.4, 6.1.3.2.6.4, and 6.1.4.2.6.4 Unused Standard Allowance, to remove the reference to non-standard street lighting facilities. These sections retain the language that states that any unused standard allowance will not be paid or credited to a Retail Customer, nor used for non-standard Delivery System facilities. This revision will reduce confusion on the part of customers involving the construction and/or installation of facilities.

Q. PLEASE DISCUSS YOUR PROPOSED REVISION TO THE STREET LIGHTING RATE SCHEDULES IN REGARD TO HOAs.

A. Currently, 6.1.1.1.8 Lighting Service, describes service to "governmental entities." However, there are some instances where no governmental entity exists that will take responsibility for needed street lights. Because street lighting enhances public safety, and because there are customers who have organized themselves into HOAs that are requesting this service from Oncor, I am proposing to revise the tariff to allow street lighting service to be available to HOAs in certain specified circumstances.

Q. PLEASE DISCUSS HOW YOU ARE PROPOSING THAT THE COMPANY ADDRESS "TINY HOMES" IN ITS RATE SCHEDULES.

A. "Tiny Homes" are a relatively new type of housing for which customers need service. While there are different types of "tiny homes," a typical scenario is one where there is a community with individual pad sites. The home is brought in on a trailer and set on a slab. If necessary, it could be moved

again to a new location. This is akin to a "mobile home," and I am proposing to revise Section 6.2.3.1.4 Mobile Homes, of the tariff to reflect this fact.

Q. IS THE COMPANY REQUESTING A REVISION TO THE TARIFF TO ALLOW FOR FLEXIBILITY IN ACCEPTING CREDIT CARD PAYMENTS?

A. Yes. There are many times when customers want to pay required fees using a credit card. I am proposing to revise the tariff by adding a new Section, 6.2.4.3 Credit Card Payments, to the Company Specific Terms and Conditions, which would allow for credit card payments when the Company deems it appropriate to do so. Payments with credit cards result in fees that must be paid to the credit card company. For this reason, the Company must be allowed to add the associated credit card fees to the required payment amount to avoid subsidization by other customers, of an amount that is intended to be paid by a specific customer or entity.

Q. PLEASE DESCRIBE THE PROPOSED TARIFF REVISION REGARDING THE ABANDONMENT OF EASEMENTS.

A. The proposed revision in Section 6.1.2.2.1.4 Space Requirements is intended to clarify that regardless of the passage of any length of time or circumstances, the Company never intends to abandon an easement unless the Company specifically states that it intends to do so, and the Company then takes specific affirmative action to effectuate the abandonment. This revision is intended to provide clarity by specifically stating our current intentions and practices and has also been added to Section 6.3 Agreements and Forms.

Q. PLEASE DISCUSS YOUR PROPOSED TARIFF REVISION CONCERNING CONTRIBUTIONS IN AID OF CONSTRUCTION.

A. Contributions in aid of construction are calculated, in part, by considering the amount of expected load and/or the number and type of dwelling units/lots that will be utilized at a particular location and facility. Currently, the Company, after four years, analyzes the actual amount of load and/or the actual number and type of dwelling units/lots. If there is a mismatch

between the load anticipated at the facility location and/or the number and type of dwelling units/lots at the time the CIAC is required, and the actual numbers four years later, then the Company can recalculate the contribution amount and invoice the customer. While the Company still intends to implement this process, more flexibility is required to better match the needs of customers with specific circumstances that may be beyond their control. The proposed revisions to Article II – Non-Utilization Clause For Standard Delivery System Facilities, Section 6.3.1 Facilities Extension Agreement would grant the Company the flexibility not to invoice the customer if the amounts would be inconsequential, if other loads exist that can utilize the additional capacity, or if four years is not the appropriate period of time to re-evaluate the situation. I believe this modification will help to better balance the needs of the customer and the needs of the Company. A similar provision has been added to the Tariff for Transmission Service.

Q. HAVE YOU PROPOSED ADDITIONAL CHANGES TO THE NON-UTILIZATION CLAUSE IN ARTICLE II OF THE FACILITIES EXTENSION AGREEMENT?

A. Yes. In conjunction with the proposed revisions discussed above, I am also proposing language that allows the Company to reset the Contract demand contained within the Facilities Extension Agreement. This language will clarify for the Customer that estimated contract capacity is not dedicated to them after a period of non-utilization. The language will also benefit other customers as it releases capacity that can then be used to serve their needs.

Q. HAVE YOU MADE ANY OTHER REVISIONS TO SECTION 6.3 AGREEMENTS AND FORMS?

A. Yes, I have. I propose adding a new section, ARTICLE V – DISCLOSURE to the agreement in Sections 6.3.1 Facilities Extension Agreement and 6.3.2 Transmission/Substation Facility Extension Agreement. This new section addresses issues and obligations concerning the disclosure to the

Company of all underground facilities owned by Customer or any other party that is not a public utility or governmental entity, that are located within real property owned by Customer. A corresponding section has also been added to Section 6.3.5 Discretionary Service Agreement.

Q. PLEASE DISCUSS CELLULAR POLE ATTACHMENTS AND ADDRESS THE ISSUES REGARDING METERING FOR THE ATTACHMENTS.

A. Recently, the push for 5G cellular service has increased. As a result, the Company is receiving requests to allow 5G devices to be mounted on Company facilities, primarily poles. The load required to serve these devices should be metered, but attaching a meter to the pole is impractical and/or unacceptable in most instances. While still in its infancy, there is a developing market for pole-top meters that can attach to the existing street light facilities. However, this type of meter is not envisioned to have a readable display and may not be accessible to the customer. Therefore, I am proposing a revision to Section 6.1.1.1.2, the Secondary Service Less Than or Equal to 10 kW rate schedule, that would allow, at the Company's sole discretion, unmetered service to these devices and associated equipment. When acceptable pole-top meters are developed, standardized, and allowed by the Commission, the unmetered service to these devices may transition to metered service, at the sole discretion of the Company, taking into consideration factors such as, but not limited to: (1) the number of devices; (2) the time requirements associated with meter installation; and (3) the associated cost.

Q. HAVE YOU ADDED LANGUAGE TO CLARIFY THE DEFINITION OF "TEMPORARY DELIVERY SERVICE"?

A. Yes. The current definition in Section 6.2.1 Definitions, states that "Temporary Delivery Service" is for a period of less than 12 months. However, the definition clarifies that construction power is still considered Temporary Delivery Service even though it may extend for a period in excess of 12 months. I have proposed additional language to clarify that

service to loads that are not of a permanent nature, are capable of being relocated to another location, or are capable of being served from an alternate source also fall under the definition of "Temporary Delivery Service." I have also made the corresponding clarification to DD8 Temporary Facilities Charge in Sections 6.1.2.2, 6.1.3.2, and 6.1.4.2 Construction Service Charges.

Q. HAVE YOU ADDED LANGUAGE TO 6.1.2.2.9 – REMOVAL AND RELOCATION OF COMPANY'S FACILITIES?

A. Yes. I am proposing additional language in Section 6.1.2.2.9 – Removal and Relocation of Company's Facilities. Language has been added to clarify that if Company Facilities are relocated at the request of a Retail Customer, the work will not begin until the requirements detailed in Section 6.1.2.2.1.4 – Space Requirements are met. Additional language has also been added that addresses cost recovery and the customer's responsibility if the customer relocates its load or removes it completely, resulting in Company facilities becoming "stranded," meaning they are not necessary to serve other customers. This section is necessary to clarify the cost-responsibility and ensure that costs are not shifted onto others. Similar language has also been added to the Tariff for Transmission Service.

Q. PLEASE DISCUSS YOUR PROPOSED REVISIONS IN REGARD TO MULTI-FAMILY DWELLINGS.

A. The current extension policy for multi-family dwellings calculates a standard allowance in a different fashion than what is detailed in Section 6.1.2.2.6.1 – Calculation of Contribution in Aid of Construction ("CIAC") for All Other Standard Facility Extensions. This creates an odd result in some instances, particularly for "quad-plexes" where the standard allowance may be less than a duplex or a single family home. To address this issue, I am proposing to alter the language in Section 6.1.2.2.6.2 – Extensions to Multi-Family Dwellings to clarify that the standard allowance for multi-family dwellings will utilize the Standard Allowance detailed in Section 6.1.2.2.6.1, and I am

proposing to alter the definition of "Multi-Family Dwelling" in Section 6.2.1 Definitions from three or more dwelling units to five or more dwelling units. The proposed revisions have also been added to the corresponding language in 6.1.3.2.6.2 and 6.1.4.2.6.2.

Q. HAVE YOU ADDED CLARIFYING LANGUAGE TO SECTION 6.3.2 – TRANSMISSION/SUBSTATION FACILITY EXTENSION AGREEMENT IN REGARD TO SECURITY PAYMENTS?

A. Yes, I have. Article 1 – Payment By Customer currently contains a reference to any required security in Section 2. However, there has been confusion over the reference at times, and thus I have proposed language that specifically states that the Company may require a security payment for up to the full cost of a project (minus any amount otherwise paid) before construction begins, and that any pertinent details will be added in Article 1, Section 2. This addition does not change anything from the Company's current practices, only adds clarity to the current provisions.

Q. PLEASE DISCUSS THE ADDITION OF A STANDARDIZED AGREEMENT FOR INTERCONNECTION OF DISTRIBUTION GENERATION RESOURCE TO SECTION 6.3 – AGREEMENTS AND FORMS.

A. Section 6.3 – Agreements and Forms is intended to memorialize documents for consistency and standardization purposes. I am proposing to add a standardized version of Oncor's Agreement For Interconnection Of Distribution Generation Resource to the tariff as this Agreement is Oncor's standard that the Company has been using for multiple years. The Agreement is also being added to the Oncor Tariff for Transmission Service for transparency purposes in case potential Customers search for the Agreement in that document.

Q. HAVE YOU ADDED LANGUAGE IN SECTION 6.3 – AGREEMENTS AND FORMS TO ADDRESS SENATE BILL 2116, "THE LONE STAR INFRASTRUCTURE PROTECTION ACT"?

A. Yes. Senate Bill 2116, recently enacted during the Regular Session of the

87th Legislature and codified in Chapter 113 of the Business and Commerce Code, prohibits contracts or other agreements with certain foreign-owned companies in connection with critical infrastructure in the state. The critical infrastructure referred to in the bill specifically applies to the electric grid. The bill restricts infrastructure agreements with certain foreign countries and does not allow them to have direct or remote access to, nor control of, any of the state's critical infrastructure. As Senate Bill 2116 applies to the electric power grid, the legislated restrictions need to be incorporated into the Tariff. Thus, I have added proposed language to the applicable agreements and forms contained in Section 6.3 that conforms with the directives of Senate Bill 2116. I propose that corresponding language also be added to the Company's Wholesale Tariffs in Section 4.9 Standard Agreements.

Q. HAVE YOU PROPOSED ANY OTHER CHANGES TO THE TARIFF FOR RETAIL DELIVERY SERVICE?

A. Yes, there are other non-substantive changes that I have made to the tariff. These are meant to simply clarify issues and "clean up" the various sections. While I am not providing an "in-depth" discussion of these non-substantive changes, I have listed the Tariff for Retail Delivery Service sections in which they occur, for easy reference.

- 6.1.1.1.1 Residential
- 6.1.1.1.2 Secondary Less Than or Equal To 10 kW
- 6.1.1.1.3 Secondary Greater Than 10 kW
- 6.1.1.1.4 Primary Less Than or Equal To 10 kW
- 6.1.1.1.5 Primary Greater Than 10 kW – Distribution Line
- 6.1.1.1.6 Primary Greater Than 10 kW – Substation
- 6.1.1.1.7 Transmission
- 6.1.1.1.8 Lighting
- 6.1.2.2 Standard Meter – Construction Service Charges

- 6.1.3.2 Non-Standard Meter – Construction Service Charges
- 6.1.4.2 AMS-M Meter – Construction Service Charges
- 6.1.2.3 Standard Meter – Service Charges – Other
- 6.1.3.3 Non-Standard Meter – Service Charges – Other
- 6.1.4.3 AMS-M Meter – Service Charges – Other
- 6.2 Company – Specific Terms and Conditions
- 6.3 Agreements and Forms

VI. TARIFF FOR TRANSMISSION SERVICE

A. Network Transmission Service

Q. PLEASE DESCRIBE THE NATURE OF WHOLESALE NETWORK TRANSMISSION SERVICE ("NTS") AND THE FACILITIES USED TO PROVIDE WHOLESALE NETWORK TRANSMISSION SERVICE.

A. The nature of wholesale NTS allows for the transmission of power from generation resources to Distribution Service Providers ("DSPs") for ultimate delivery to loads in the ERCOT region. In limited circumstances, wholesale NTS is also used to export power to or from the ERCOT region across DC ties. Generally, facilities operated at or above 60 kilovolts are deemed to be transmission facilities. 16 TAC § 25.192(c)(1) lists the specific facilities deemed to be transmission facilities.

Q. WHICH MARKET PARTICIPANTS PAY FOR WHOLESALE NTS?

A. Because of the highly integrated nature of the ERCOT transmission network that is owned by multiple TSPs and the need to facilitate the development of the wholesale generation market, the Commission determined that the most appropriate structure to ensure recovery of costs for this integrated network whose benefits are realized by all market participants was through the development of a postage stamp rate (*i.e.,* the sum of all of the TSPs' individual NTS rates) that all DSPs pay. DSPs in areas with retail competition then pass these costs on to REPs through the DSPs' rates for retail delivery service or directly to customers through an integrated tariff for

DSPs in non-competitive markets.

Q. WHAT RATE SCHEDULE ARE YOU PROPOSING FOR NTS, AND HOW IS THE RATE DESIGNED?

A. Rate NTS – Network Transmission Service, is designed to recover the Company's transmission cost of service ("TCOS") revenue requirement through a rate that is applicable to all DSPs. This rate is computed using the ERCOT-wide postage stamp method as required by 16 TAC § 25.192. The Company's total TCOS revenue requirement for the TRAN function of $1,445,176,353 found in RFP Schedule I-A-1, is divided by 72,490,325.252 kW, the ERCOT average 4CP load for the four on-peak months June 2021 – September 2021, from Docket No. 52989 – *Commission Staff's Petition To Set 2022 Wholesale Transmission Service Charges For the Electric Reliability Council of Texas*, to determine the Company's postage stamp transmission rate of $19.936127 per kW, or $19,936.127 per MW.

Q. IS THIS THE NTS RATE THAT YOU ARE RECOMMENDING TO GO INTO EFFECT UPON THE CONCLUSION OF THIS RATE CASE?

A. Perhaps not. Due to the timing of the prosecution of this rate case and the interim TCOS updates that are permitted under 16 TAC § 25.192(h)(1), it is probable that Oncor will have filed and been granted approval of at least one interim TCOS update that may not be reflected in the NTS rate approved in this rate case. Oncor typically files interim TCOS updates in January (investment through December) and July (investment through June). Therefore, Oncor proposes to incorporate in its rate case compliance tariff filing the results of any interim TCOS changes approved between December 31, 2021, and the conclusion of this rate case.

Q. BY FACTORING IN THESE INTERIM TCOS UPDATES AT THE CONCLUSION OF THE RATE CASE, ARE YOU SUGGESTING THAT THE TRANSMISSION INVESTMENTS THAT OCCURRED BEYOND THE TEST YEAR IN THIS RATE CASE BE DEEMED PRUDENT?

A. No. Just as this rate case includes a prudence review of those transmission

capital investments that were made between January 1, 2017, and December 31, 2021, Oncor proposes that the prudence review of transmission investments that are made after December 31, 2021, be conducted in Oncor's next general rate case.

Q. WHAT WAS THE DATE OF YOUR LAST INTERIM TCOS UPDATE?

A. Oncor filed its last interim TCOS update in Docket No. 53145 on January 26, 2022, for investments through December 31, 2021. The timing of the end of the investment period coincided with the end of the rate case test year.

B. Wholesale Transmission Service at Distribution Voltage

Q. WERE THE WHOLESALE RATE CLASSES INCLUDED IN THE CLASS COST OF SERVICE STUDY THAT YOU PREPARED?

A. Yes. The Cost of Service study calculates the revenue requirement attributable to customers who take service under Rates XFMR – Wholesale Substation Service and Rate DLS – Wholesale Distribution Line Service based on the fully-allocated system average methodology typically used to determine the revenue requirement for customer classes.

Q. PLEASE DESCRIBE RATES XFMR – WHOLESALE SUBSTATION SERVICE AND DLS – WHOLESALE DISTRIBUTION LINE SERVICE.

A. Rates XFMR and DLS are essentially the wholesale service equivalents of the Primary Service Greater Than 10 kW – Substation and the Primary Service Greater Than 10 kW – Distribution Line rates, respectively. Typically, the wholesale customer taking service on one of these two rate schedules is an electric distribution cooperative, but in some cases the customer is a generation and transmission cooperative or wholesale storage load. Wholesale points-of-delivery served on Rate XFMR take service from Oncor that has been transformed from one of the Company's standard transmission voltages to one of the Company's standard primary voltages less than 60 kV, typically at or adjacent to an Oncor-owned substation. Wholesale points-of-delivery served on Rate DLS take service

from Oncor that has been transformed to one of the Company's standard primary voltages less than 60 kV, and are located more than one span away from the Oncor-owned substation. From a cost causation standpoint, the costs imposed on the Company to serve wholesale customers served under Rates XFMR and DLS are comparable to the cost of serving similarly situated retail customers.

Q. PLEASE EXPLAIN WHY YOU ARE PROPOSING TO LIMIT THE APPLICATION OF RATE XFMR – WHOLESALE SUBSTATION SERVICE TO NEW CUSTOMERS.

A. In circumstances where the Company has invested in the distribution facilities necessary to serve individual loads, a combination of loads would impair the Company's ability to recover the full costs incurred to serve the loads. This scenario creates a de-facto stranded investment and would result in a subsidy of the combined load by the Company's other ratepayers. To prevent this scenario, I propose to limit the eligibility for Rate XFMR to new Points of Delivery and the service may not be used when combining new Points of Delivery with existing load or combining existing Points of Delivery. This provision is the same as proposed when establishing a new point of delivery taking service under the Primary Service Greater Than 10 kW–Substation Rate in Section 6.1.1.1.6 of the Tariff for Retail Delivery Service.

C. Wholesale Transmission Discretionary Service

Q. ARE YOU PROPOSING ANY CHANGES TO THE TRANSMISSION DISCRETIONARY SERVICE CHARGES?

A. No, I am not.

D. Wholesale Transmission Service Riders

Q. WHAT CHANGES ARE YOU PROPOSING TO THE VARIOUS RIDERS CURRENTLY INCLUDED IN THE COMPANY'S TARIFF FOR WHOLESALE TRANSMISSION SERVICE?

A. I am proposing to delete the following riders:

- Rider WRS – Wholesale Remand Surcharge;
- Rider WTRF-N – Wholesale Tax Refund Factor (NTS);
- Rider WTRF – Wholesale Tax Refund Factor (XFMR & DLS); and
- Rider WTU – Wholesale True Up Credit Rider.

I propose to delete these riders because all applicable expenses and/or credits have been recovered (or credited) and, as a result, these riders are no longer applicable.

I am also proposing to delete the following riders:

- Rider WCSR – Wholesale Capital Structure Refund; and
- Rider WMSC – Wholesale Merger Savings Credit.

I propose to delete these riders because the benefits that accrue to wholesale customers from these riders are incorporated into the rate class revenue requirements for wholesale customers in this rate filing and, as a result, these riders will no longer be applicable when an order is rendered in this case.

E. Service Regulations and Standard Agreements

Q. ARE YOU PROPOSING ANY CHANGES TO CHAPTER 4 SERVICE REGULATIONS AND STANDARD AGREEMENTS OF THE TARIFF FOR TRANSMISSION SERVICE?

A. Yes. I am proposing to modify the definition of "Facility Connection Requirements" in Section 4.2 Definitions.

Q. PLEASE EXPLAIN WHY THIS CHANGE IS NECESSARY.

A. The change is necessary to remove redundant language. The revisions are non-substantive and clarify the requirements for connecting with the Company's transmission system.

Q. ARE YOU PROPOSING ANY OTHER CHANGES TO CHAPTER 4?

A. Yes. In Section 4.3.1.2 Company's Standard Transmission and Distribution Voltages, I am proposing to add language that clarifies that service at 345kV may be limited due to safety and reliability concerns.

Q. HAVE YOU ADDED A PROVISION TO THE TARIFF FOR TRANSMISSION SERVICE ADDRESSING STRANDED FACILITIES?

A Yes. I am proposing additional language in Section 4.8.1 Discontinuance of Service to Chapter 4 Service Regulations and Standard Agreements of the Tariff for Transmission Service. This new language addresses cost recovery and the customer's responsibility when the customer removes its load (such as if it relocates equipment), resulting in Company facilities becoming "stranded," meaning they are not necessary to serve other customers. This section is necessary to clarify the cost-responsibility.

VII. ONCOR NTU TARIFF FOR TRANSMISSION SERVICE

Q. HAVE YOU MADE THE CORRESPONDING CHANGES TO THE ONCOR NTU, TARIFF FOR TRANSMISSION SERVICE?

A. Yes, I have. The Oncor NTU Tariff is essentially the same as the Oncor Tariff for Transmission Service.

Q. HOW IS RATE WTS – WHOLESALE TRANSMISSION SERVICE, DEVELOPED FOR ONCOR NTU?

A. In this rate case, the Transmission Function Revenue Requirement reflects both Oncor and Oncor NTU. Thus, there is only one Network Transmission Service rate that is applicable.

Q. WILL DSPs BE CHARGED RATE WTS BY ONCOR NTU AND NTS BY ONCOR??

A. No, they will not. Essentially, Oncor and Oncor NTU are being combined for rate purposes. DSPs will only pay Rate NTS to Oncor.

Q. HOW IS RATE WDSS – WHOLESALE DISTRIBUTION SUBSTATION SERVICE DEVELOPED FOR ONCOR NTU?

A. Rate WDSS is the Oncor NTU equivalent of Oncor's Rate XFMR – Wholesale Substation Service. As with Oncor's Rate XFMR, Oncor NTU's Rate WDSS is a separate rate class. The rate charges associated with Oncor NTU's Wholesale Distribution Substation Service are based upon the revenue requirement associated with that rate class.

Q. WILL RATE WDSS BE CHARGED BY ONCOR NTU?

A. Yes. Unlike Rate WTS, Oncor NTU will still charge Rate WDSS to its only customer, Oncor. Rate WDSS is designed to recover the Oncor NTU distribution revenue requirement as shown on Schedule I-A-1, column (k), line 16. Any wholesale customer requiring service from an Oncor NTU substation will receive service under Oncor's Tariff for Transmission Service, Rate XFMR or Rate DLS, whichever is appropriate.

Q. IS THIS RATE TREATMENT FOR ONCOR NTU CONSISTENT WITH THE MAY 9, 2019 ORDER IN DOCKET NO. 48929?

A. Yes. Finding of Fact 49 of the Order in Docket No. 48929[10] states that a separate wholesale-transmission rate and tariff is established for Oncor NTU. Additionally, Ordering Paragraph 16 states that Oncor must consolidate Oncor NTU with Oncor for ratemaking purposes and make a combined rate filing in Oncor's next base-rate case. Thus, in this proceeding, Oncor and Oncor NTU have been combined for ratemaking purposes, but they remain separate legal entities.

Q. HAVE YOU REMOVED ANY RIDERS FROM THE ONCOR NTU TARIFF FOR TRANSMISSION SERVICE?

A. Yes, I have. Rider TC – Transition Costs is no longer applicable, so I have deleted it from the NTU tariff.

VIII. OTHER SERVICES

Q. WHAT DO "OTHER SERVICES" INCLUDE?

A. 16 TAC § 25.342(f)(1)(D) defines "Other Services" as any other services not included in the functional categories, limited to those services that:

1. maximize the value of transmission and distribution system service facilities; and
2. are provided without additional personnel and facilities other than those essential to the provision of transmission and distribution services.

[10] *Joint Report and Application of Oncor Electric Delivery Company LLC, Sharyland Distribution & Transmission Services L.L.C., Sharyland Utilities L.P., and Sempra Energy for Regulatory Approvals Under PURA §§ 14.101, 37.154, 39.262 and 39.915*, Docket No. 48929 (May 9, 2019).

Q. DOES THE COMPANY PROPOSE TO OFFER OTHER SERVICES?

A. Yes. Oncor plans to offer the same other services that it currently offers. These other services include: (1) Communications Access Service, such as telephone company, fiber-optic cable installations, and cable TV company attachment to, and use of, transmission and distribution system facilities pursuant to individually negotiated contracts or Federal Communications Commission-mandated pricing methodology; and (2) Real Property Rights, such as the sale of real property or the granting of other property rights (including leases, easements, and licenses for the installation of customer facilities on the Company's property), and related studies to determine the appropriateness of the transaction.

Q. HOW DOES THE COMPANY PLAN TO ACCOUNT FOR AND PROVIDE THESE OTHER SERVICES?

A. Oncor plans to separately track the revenues associated with each of these services (and costs where possible) so that the revenues may be used to reduce the transmission and/or distribution system cost. The Company also plans to continue to provide these services in a non-discriminatory manner.

IX. CONCLUSION

Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY.

A. The Company has prepared a rate class cost of service study that utilizes Commission-approved cost allocation methodologies to assign costs to the various rate classes. I have used the results of this study to design distribution services rates for the retail and wholesale rate classes to equitably recover the costs incurred by the Company. In addition, I have calculated the combined NTS rate for Oncor and Oncor NTU, as well as Oncor NTU rate WDSS. I have also described proposed revisions to the Company's Tariff for Retail Delivery Service and the Company's Tariffs for Transmission Service. The tariffs proposed in this case contain rate schedules and terms and conditions that are consistent with applicable

Commission Substantive Rules. The proposed rates, Service Regulations, and Standard Agreements are just and reasonable and should be approved by the Commission.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

STATE OF TEXAS §
§
COUNTY OF DALLAS §

BEFORE ME, the undersigned authority, on this day personally appeared Matthew A. Troxle, who, having been placed under oath by me, did depose as follows:

My name is Matthew A. Troxle. I am of legal age and a resident of the State of Texas. The foregoing direct testimony and the attached exhibits offered by me are true and correct, and the opinions stated therein are, to the best of my knowledge and belief, accurate, true, and correct.

Matthew A. Troxle

SUBSCRIBED AND SWORN TO BEFORE ME by the said Matthew A. Troxle this 2nd day of May, 2022.

TERI SMART
Notary Public, State of Texas
Comm. Expires 11-13-2024
Notary ID 514088-5

Notary Public, State of Texas

Oncor Electric Delivery Company LLC
List of Matthew A. Troxle's Prior Commission Testimony

- **Arkansas Public Service Commission:**

Docket No. 10-010-U – *In The Matter Of A Notice Of Inquiry Into Energy Efficiency – March 2010, Rebuttal – April 2010.*

Docket No. 07-081-TF – *In The Matter Of The Application Of CenterPoint Energy Arkansas Gas For Approval Of Its "Quick Start" Energy Efficiency Program, Portfolio And Plan Including Its Cost Recovery Rider – July 2009, Rebuttal – September 2009, Sur-rebuttal – October 2009.*

- **Louisiana Public Service Commission:**

Docket No. U-33437 – *Report Of Earnings And Return On Equity For The Louisiana Division For The Twelve Months Ending June 30, 2014 For CenterPoint Energy Arkla – June 2016.*

Docket No. U-33438 – *Report of Earnings and Return On Equity For The Louisiana Division For The Twelve Months Ending June 30, 2014 For CenterPoint Energy Entex – June 2016.*

- **Mississippi Public Service Commission:**

Docket No. 2018-UN-71 – *Notice Of CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Mississippi Gas, Of The Filing Of Routine Changes In Its Rate Regulation Adjustment Rider – May 2018.*

Docket No. 2018-UN-72 – *Notice Of CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Mississippi Gas, Of The Filing Of Routine Changes In Its Supplemental Growth Rider – May 2018.*

- **Public Utilities Commission Of The State Of Minnesota:**

Docket No. G-008/GR-15-424 – *In The Matter Of The Application Of CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Minnesota Gas For Authority To Increase Rates For Natural Gas Utility Service In Minnesota – August 2015, Rebuttal – December 2015, Sur-rebuttal – January 2016.*

Docket No. G-008/GR-13-316 – *In The Matter Of The Application Of CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Minnesota Gas For Authority To Increase Rates For Natural Gas Utility Service In Minnesota – August 2013, Rebuttal – December 2013.*

Docket No. G-008/GR-08-1075 – *In The Matter Of The Application Of CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Minnesota Gas For Authority To Increase Rates For Natural Gas Utility Service In Minnesota – November 2008, Rebuttal – July 2009.*

Oncor Electric Delivery Company LLC
List of Matthew A. Troxle's Prior Commission Testimony

- **Public Utility Commission Of Texas:**

Docket No. 53145 – *Application Of Oncor Electric Delivery Company LLC For Interim Update Of Wholesale Transmission Rates – January 2022.*

Docket No. 52352 – *Application Of Oncor Electric Delivery Company LLC For Interim Update Of Wholesale Transmission Rates – July 2021.*

Docket No. 52178 – *Application Of Oncor Electric Delivery Company LLC to Adjust Its Energy Efficiency Cost Recovery Factor – May 2021.*

Docket No. 51996 – *Application Of Oncor Electric Delivery Company LLC For Approval to Amend Its Distribution Cost Recovery Factor – April 2021.*

Docket No. 51767 – *Application Of Oncor Electric Delivery Company LLC For Interim Update Of Wholesale Transmission Rates – January 2021.*

Docket No. 51115 – *Application Of Oncor Electric Delivery Company LLC For Interim Update Of Wholesale Transmission Rates – July 2020.*

Docket No. 50886 – *Application Of Oncor Electric Delivery Company LLC to Adjust Its Energy Efficiency Cost Recovery Factor – May 2020.*

Docket No. 50734 – *Application Of Oncor Electric Delivery Company LLC For Approval to Amend Its Distribution Cost Recovery Factor – April 2020.*

Docket No. 50490 – *Application Of Oncor Electric Delivery Company LLC For Interim Update Of Wholesale Transmission Rates – January 2020.*

Docket No. 49421 – *Application Of CenterPoint Energy Houston Electric, LLC For Authority To Change Rates – April 2019, Rebuttal – June 2019.*

Docket No. 44572 – *Application Of CenterPoint Energy Houston Electric, LLC For Approval Of A Distribution Cost Recovery Factor Pursuant To P.U.C. Substantive Rule 25.243 – April 2015, Rebuttal – June 2015, Settlement – June 2015.*

Docket No. 42111 – *Complaint Of Nawaid Isa Against Ambit Energy And CenterPoint Energy Houston Electric, LLC – April 2015.*

Docket No. 41906 – *Compliance Filing Of CenterPoint Energy Houston Electric, LLC For Approval Of A Revised Tariff For Retail Delivery Service In Compliance With New Substantive Rule 25.133 And Revised Substantive Rule 25.214 – September 2013, Settlement – April 2014.*

Docket No. 41540 – *Application Of CenterPoint Energy Houston Electric, LLC, For Approval Of An Adjustment To Its Energy Efficiency Cost Recovery Factor – May 2013.*

Docket No. 40356 – *Application Of CenterPoint Energy Houston Electric, LLC, For Approval Of An Adjustment To Its Energy Efficiency Cost Recovery Factor – May 2012.*

Oncor Electric Delivery Company LLC
List of Matthew A. Troxle's Prior Commission Testimony

Docket No. 39933 – *Application Of CenterPoint Energy Houston Electric, LLC, For Interim Update Of Wholesale Transmission Rate Pursuant To P.U.C. Substantive Rule §25.192(h)(1) – November 2011.*

Docket No. 39066 – *Claims For September – December 1999 Period Severed From Docket No. 38780 (Remand Of Docket No. 20381, Proceeding To Modify ERCOT Transmission Rates For 1999 Pursuant To Subst. R. 23.67 – August 2011.*

Docket No. 39633 – *Application Of CenterPoint Energy Houston Electric, LLC, For Interim Update Of Wholesale Transmission Rate Pursuant To P.U.C. Substantive Rule §25.192(h)(1) – August 2011.*

Docket No. 39363 – *Application Of CenterPoint Energy Houston Electric, LLC, For Approval Of An Adjustment To Its Energy Efficiency Cost Recovery Factor – April 2011, Rebuttal – August 2011.*

Docket No. 38339 – *Application Of CenterPoint Electric Delivery Company, LLC, For Authority To Change Rates – June 2010, Rebuttal – October 2010.*

Docket No. 36701 – *Petition Of Texas Utility Solutions LLS For Declaratory Order Of Eligibility As A Transmission Service Customer – February 2010.*

Docket No. 32766 – *Application Of Southwestern Public Service Company For (1) Authority To Change Rates; (2) Reconciliation Of Its Fuel Costs For 2004 And 2005; (3) Authority To Revise The Semi-Annual Formulae Originally Approved In Docket No. 27751 Used To Adjust Its Fuel Factors; And (4) Related Relief – January 2007.*

Docket No. 32907 – *Application Of Entergy Gulf States, Inc. For Determination Of Hurricane Reconstruction Costs – October 2006.*

Docket No. 32093 – *Petition By Commission Staff For A Review Of The Rates Of CenterPoint Energy Houston Electric, LLC Pursuant To PURA §36.151 – August 2006.*

Docket No. 28466 – *Application Of Cap Rock Energy Corporation For Electric Service Tariff – August 2005.*

Docket No. 30216 – *Notice Of Violation By Cap Rock Energy Of PURA Section 36.004(a) Relating To Equality Of Service And Rates And P.U.C. Subst. R. 25.241(b) Relating To Form And Filing Of Tariff – April 2005, Rebuttal – June 2005.*

Docket No. 30215 – *Notice Of Violation By Cap Rock Energy Of P.U.C. Subst. R. 25.28(b) Relating To Bill Payments And Adjustments – April 2005, Rebuttal - June 2005.*

Docket No. 30706 – *Application Of CenterPoint Energy Houston Electric, LLC For A Competition Transition Charge (CTC) – March 2005.*

Oncor Electric Delivery Company LLC
List of Matthew A. Troxle's Prior Commission Testimony

Docket No. 28813 – *Petition To Inquire Into The Reasonableness Of The Rates And Services Of Cap Rock Energy Corporation – September 2004.*

Docket No. 28840 – *Application Of AEP Texas Central Company For Authority To Change Rates – February 2004.*

Docket No. 28980 – *Petition Of CenterPoint Energy Houston Electric, LLC For Finding That The 40% Threshold Under PURA §39.202(e) Has Been Met For Small Commercial Customers – January 2004.*

Docket No. 28563 – *Compliance Filing Of Oncor Electric Delivery Company Pursuant To Subst. R. 25.311 Regarding Competitive Meter Ownership – November 2003.*

Docket No. 28562 – *Compliance Filing And Petition Of CenterPoint Energy Houston Electric, LLC To Provide Competitive Metering Service Credit Pursuant To PUC Subst. R. 25.311 – November 2003.*

Docket No. 28560 – *Compliance Filing Of AEP Texas North Company To Provide Competitive Metering Credit – November 2003.*

Docket No. 28559 – *Compliance Filing Of AEP Texas Central Company To Provide Competitive Metering Credit – November 2003.*

Docket No. 28556 – *Texas-New Mexico Power Company's Compliance Filing To Provide Competitive Metering Credit Pursuant To Subst. R. 25.311 – November 2003.*

Docket No. 28585 – *Application Of TXU SESCO Energy Services Company To Increase Price To Beat Fuel Factors And Reduce Price To Beat Base Rates – October 2003 – Adopted Testimony of Brian H. Lloyd.*

Docket No. 25421 – *Application Of LCRA Transmission Services Corp. To Charge Rates For Transmission And Transformation Utility Cost Of Service – October 2002.*

Docket No. 25429 – *Appeal Of Oncor From An Ordinance Of The City Of Allen And Request For Interim Relief – August 2002.*

Docket No. 25960 – *Application Of Brazos Electric Power Cooperative, Inc. To Change Rates For Wholesale Transmission Service – Interim Rates Phase – August 2002.*

Docket No. 25874 – *Application Of Mutual Energy WTU, LP To Increase Price To Beat Fuel Factors – May 2002.*

Docket No. 24449 – *Application Of Southwestern Electric Power Company To Implement The Fuel Factor Component Of Price To Beat Rates – October 2001.*

Docket No. 24336 – *Application Of Entergy Gulf States, Inc. For Approval Of Price To Beat Fuel Factor – September 2001.*

Oncor Electric Delivery Company LLC
List of Matthew A. Troxle's Prior Commission Testimony

Docket No. 24194 – *Application Of Texas-New Mexico Power Company To Establish Price To Beat Fuel Factor – August 2001.*

Docket No. 24040 – *Application Of TXU Electric Company To Implement Price To Beat Fuel Factors – August 2001.*

Docket No. 23950 – *Petition Of Reliant Energy, Inc. To Establish Price To Beat Fuel Factor and Request For Good Cause Exception To Subst. R. 25.41 – July 2001.*

Docket No. 22351 – *Application Of Southwestern Public Service For Approval Of Unbundled Cost Of Service Rate Pursuant To PURA §39.201 And Public Utility Commission Substantive Rule §25.344 – February 2001.*

Docket No. 22350 – *Application Of TXU Electric Company For Approval Of Unbundled Cost Of Service Rate Pursuant To PURA §39.201 And Public Utility Commission Substantive Rule §25.344 – February 2001.*

Docket No. 22356 – *Application Of Entergy Gulf States Inc. For Approval Of Unbundled Cost Of Service Rate Pursuant To PURA §39.201 And Public Utility Commission Substantive Rule §25.344 – January 2001.*

Docket No. 22355 – *Application Of Reliant Energy Incorporated For Approval Of Unbundled Cost Of Service Rate Pursuant To PURA §39.201 And Public Utility Commission Substantive Rule §25.344 – December 2000.*

Docket No. 22350 – *Application Of TXU Electric Company For Approval Of Unbundled Cost Of Service Rate Pursuant To PURA §39.201 And Public Utility Commission Substantive Rule §25.344 – November 2000.*

Docket No. 22349 – *Application Of Texas-New Mexico Power Company For Approval Of Unbundled Cost Of Service Rate Pursuant To PURA §39.201 And Public Utility Commission Substantive Rule §25.344 – ECOM Phase – September 2000.*

- **Railroad Commission Of Texas:**

Docket No. 9902 – *Statement Of Intent Of CenterPoint Energy Resources Corp., D/B/A CenterPoint Energy Entex And CenterPoint Energy Texas Gas To Increase Rates On A Division Wide Basis In The Houston Division – July 2009, Rebuttal – October 2009.*

2022 RATE CASE
ONCOR ELECTRIC DELIVERY COMPANY LLC
CALCULATION OF TRANSMISSION REVENUE REQUIREMENT FOR RETAIL DELIVERY SERVICE
TEST YEAR ENDING DECEMBER 31; 2021
SPONSOR: M. TROXLE

Current ERCOT Wholesale Transmission Access Fees

Transmission Owners/Load Entities	Current Access Fee ($ / kW)
AEP Texas	8 197657000
Austin Energy	1 187214000
Bandera Electric Coop	0 079465000
Brazos Electric Coop	1 889953700
Brownsville Public Utilities Board	0 138873000
Bryan Texas Utilities	0.511284000
Centerpoint Energy	5 852280000
Cherokee County Electric Coop	0.002892000
College Station, City of	0 055256400
Cross Texas Transmission LLC	0.995200000
Deep East Texas Electric Coop	0.002092000
Denton Municipal Electric	0 842324100
East Texas Electric Coop	0.003530000
Electric Transmission Texas	4.693082000
Fannin Electric Coop	0.002192000
Farmers Electric Coop	0.009901000
Floresville Electric Power System	0 006443000
Garland Power and Light	0.908861000
Greenville Electric Utility System	0.045180000
Golden Spread Electric Coop	0.035250000
Grayson-Collin Electric Coop	0.022728000
Houston County Electric Coop	0.019677000
Lamar County Electric Coop	0 004135000
Lone Star Transmission	1.358724000
Lower Colorado River Authority	7.979188600
Lubbock Power & Light	0 576270000
Lyntegar Electric Coop	0 011365000
Rayburn Country	0 330116100
Rio Grande Electric Coop	0.009859000
San Antonio City Public Service	3.084305000
San Bernard Electric Coop	0.057070000
San Miguel Electric Coop	0.020501000
Sharyland Utilities	0.563436000
South Texas Electric Coop	1.291537000
Southwest Texas Electric Coop	0.000951000
Texas Municipal Power Agency	0 435470000
Texas-New Mexico Power Company	1.459023000
Trinity Valley Electric Coop	0.010713000
Wind Energy Transmission Texas LLC	1.809540000
Wood County Electric Coop	0.001899000
Oncor Electric Delivery NTU	2.386843198
Oncor Electric Delivery	$17 549284119
Total ERCOT Transmission Access Fee	$64.441565217 / kW

Oncor Electric Delivery Average 4-CP Load (as shown below) 25,945,084.560 kW

Oncor Electric Delivery -- Transmission Revenue Requirement for Retail Delivery Service=	**$1,652,522,021**

Transmission Expense Riders	Annualized Rider	Annual Expense
Wind Energy Transm - Tax Rate Change	-0.143640000	(3,726,751.95)
Wind Energy Transm - WTS Credit	-0 236892000	(6,146,182.97)
Rayburn County - WTS Credit Rider	-0 062077250	(1,610,599 50)
Texas New Mexico Power - Rate Case Expense surc	0 002810000	72,905.69
East Texas Electric - WTS Credit Rider	-0.014088000	(365,514.35)
Brownsville PUB - Rate Case Expense surcharge	0 003480000	86,758.18
Lubbock Power & Light - WTS Credit Rider	-0.310080000	(7,730,452.65)
Subtotal, Transmission Expense Riders		**(19,419,837.56)**

Oncor's TCOS rate in effect during the test year (from Docket No 52352, effective 9/20/2021) $ 16.840547180
Oncor NTU's rate currently in effect, prior to this filing (from Docket No 48929 & 49519) $ 3.226341000
Oncor's TCOS rate currently in effect, prior to this filing (from Docket No. 53145) $ 17 212955892

	ERCOT kW	Oncor Electric Delivery kW	Source
Jun 2021	70,393,637 448	24,667,665 860	Docket No 52989
Jul 2021	73,305,140.020	26,269,921 052	Docket No 52989
Aug 2021	73,822,003.984	26,160,386 920	Docket No 52989
Sep 2021	72,440,519.556	26,682,364 408	Docket No 52989
Average	**72,490,325.252**	**25,945,084.560**	

2022 RATE CASE
ONCOR ELECTRIC DELIVERY COMPANY LLC
WORKPAPERS FOR
THE DIRECT TESTIMONY OF
MATTHEW A. TROXLE

Mr. Troxle has no supporting workpapers for his direct testimony.

INDEX TO THE DIRECT TESTIMONY OF
DARRYL E. NELSON, WITNESS FOR
ONCOR ELECTRIC DELIVERY COMPANY LLC

DIRECT TESTIMONY OF DARRYL E. NELSON

I. POSITION AND QUALIFICATIONS

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

A. My name is Darryl E. Nelson. I am Senior Manager, Regulatory Rates and Load Research with Oncor Electric Delivery Company LLC ("Oncor" or "the Company"). My office address is 1616 Woodall Rodgers Freeway, Floor 6, Dallas, Texas 75202.

Q. PLEASE OUTLINE YOUR EDUCATION, EXPERIENCE AND PROFESSIONAL QUALIFICATIONS.

A. I have a Bachelor of Business Administration degree in quantitative analysis and marketing from Baylor University. I have 40 years of experience with Oncor and its predecessor companies and affiliate business units in a wide array of disciplines. The primary focus of my work experience has been in the areas of load research, pricing, load forecasting, load profiling, and energy efficiency.

Q. HAVE YOU FILED TESTIMONY BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS ("COMMISSION") OR ANY OTHER REGULATORY BODY?

A. Yes. I provided direct testimony in Oncor's two most recent base rate cases, Docket Nos. 46957 and 38929.

Q. HOW HAVE YOUR PAST EXPERIENCES PREPARED YOU TO SERVE AS AN EXPERT WITNESS FOR THE SUBJECT MATTER OF YOUR TESTIMONY?

A. For most of my career, I have held positions in the Company and its predecessors and affiliates that required me to perform and to review detailed analyses of the load on Oncor's system. From 1982 to 1988, I worked in the Conservation and Management group, where my duties included analyzing energy efficiency programs and developing and analyzing the results of appliance saturation surveys. From 1988 to 1999, I held various load research positions with increasing levels of responsibility

in the rate department of Oncor's vertically integrated predecessor utility. My primary duties in those roles included developing and analyzing load research data and designing load data requirements for rate design purposes. In 1999, as Oncor's representative, I led the Electric Reliability Council of Texas ("ERCOT") Working Group that developed load profiles for the market in response to the deregulation of the electric market resulting from Senate Bill 7. From 2001 to 2005, I worked at TXU Energy Trading and TXU Energy in various positions. In those jobs, I developed load shapes, determined customer pricing structures, and performed load forecasting. Since 2006, I have been back in the Rates group at Oncor, where I have served as the liaison between the Load Research and Rates groups and have been responsible for regulatory issues associated with distributed generation and energy storage, including the Company's energy efficiency efforts. I currently manage the team responsible for the Company's continuing program of load research. I have been involved in and performed analyses for load research, rate design, and energy efficiency in six of Oncor's past rate cases. In Oncor's most recent rate case (Docket No. 46957), I filed direct testimony addressing the same issues I will be supporting in this case.

Through years of evaluating load data, I have become familiar with the statistical models used to analyze the load served by the Company. My educational background, analytical load expertise, and rate case witness experience enable me to understand load information and to develop the adjustments I describe in my testimony.

II. PURPOSE OF DIRECT TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my direct testimony is to present and support the reasonableness of the following test year adjustments, which were made using methodologies that have been previously approved by the Commission:

- adjustments to energy sales, demands, customers, and revenues resulting from the year-end customer growth adjustments;
- adjustments to energy sales, demands, and revenues resulting from weather normalization adjustments; and
- adjustments to demands and revenues resulting from the power factor provision adjustments.

References to "customer" and "consumer" in my direct testimony relate to the retail end-use electricity consumer whose electric facilities are connected to the Oncor transmission and distribution system for receipt of power that is purchased from a Retail Electric Provider ("REP").

Q. WHAT SCHEDULES OF THE RATE FILING PACKAGE ("RFP") ARE YOU SPONSORING AND/OR CO-SPONSORING?

A. Please refer to Exhibit DEN-1 for a list of RFP schedules that I sponsor.

Q. PLEASE DESCRIBE THE SCHEDULES THAT YOU SPONSOR.

A. Schedule II-H-1.1: Test Year Sales Data – This schedule provides test-year-end and average number of billed customers; booked kilowatt-hours ("kWh"); kWh sales adjustments for weather normalization and customer growth; and adjusted kWh by rate class for the test year ending December 31, 2021. Adjustments to booked kWh include an increase of 1,413,717,519 kWh to normalize the effects of test year temperature conditions and an increase of 1,776,817,682 kWh to annualize sales to account for the test year-end number of customers.

Schedule II-H-1.1.1: Test Year Energy Flows Across DC Ties – For each Oncor-owned DC tie connected to non-ERCOT regions, this schedule provides monthly energy inflows and outflows (in kWh) for the test year.

Schedule II-H-1.2: Monthly Sales Data – This schedule provides billed and test-year-end number of customers; booked kWh; kWh sales adjustments for weather normalization and customer growth; and adjusted kWh by rate class by month for each month of the test year ending December 31, 2021.

Schedule II-H-1.3: Unadjusted Test Year Load Data – This schedule provides the following unadjusted historical monthly data for the test year: kilowatt ("kW") coincident peak demands at the times of the ERCOT system peak, demands at the times of the Oncor system peak, class peak demands, and sum of customers' maximum demands; kWh sales; and coincidence factors and load factors by rate class by delivery voltage level at the meter and at the system transmission delivery voltage (*i.e.*, at the "source"). This schedule also provides monthly coincident factors and load factors for the 36 months prior to the test year by rate class.

Schedule II-H.1.3.1: Adjustments to Test Year Load Data – This schedule provides the adjustment made to the load data in Schedule II-H.1.3 for each rate class and each month of the test year. This schedule also provides a narrative explaining each adjustment.

Schedule II-H-1.3.2: DC Tie Load Data – For each Oncor-owned DC tie connected to non-ERCOT regions, this schedule provides monthly 15-minute peak demands for inflows and outflows (in kW) for the test year.

Schedule II-H.1.4: Adjusted Test Year Load Data – This schedule provides the following adjusted monthly data: kW coincident peak demands at the times of ERCOT system peak, demands at the times of the Oncor system peak, class peak demands, and sum of customers' maximum demands; kWh sales; and coincidence factors and load factors by rate class by delivery voltage level at the meter and at the source. These adjusted values

include the effects of the customer growth and weather normalization adjustments.

Schedule II-H-1.5: Adjustments to Operating Statistics – This schedule provides a narrative explanation of the procedures used to make the energy and demand adjustments for weather normalization, energy and demand adjustments for customer growth, and the demand annualization adjustments.

Schedule II-H-2.1: Model Information – This schedule provides the functional specifications, model coefficients, and summary regression statistics of the econometric models employed to develop the weather normalization adjustments to rate classes.

Schedule II-H-2.2: Model Data – This schedule provides a listing of the data used by the Company to develop the weather normalization regression models.

Schedule II-H-2.3: Model Variables – This schedule provides the historical price index used in the final regression models.

Schedule II-H-3.1: Customer Information – This schedule requires monthly customer information by rate class. As indicated in our filing, Schedule II-H-3.1 refers to that information being provided on Schedule II-H-1.2.

Schedule II-H-3.2: Customer Adjustments – This schedule provides narrative descriptions and numeric examples of the calculation of customer adjustments to kWh sales and billing kW for each class of service.

Schedule II-H-3.3: Customer Adjustment Data – This schedule relates to proposed customer adjustments that are provided on Schedule II-H-1.2.

Schedule II-H-4.1: Revenue Impact Data – This schedule provides the unadjusted number of customers, kWh, transmission and distribution billing demands by rate class and revenue by type (*i.e.*, customer, meter, transmission, distribution, DCRF, TCRF, and total); adjustments to revenues and annual billing units for each of these billing functions for the rate annualization, customer kWh growth, customer kW demand growth,

kWh weather normalization, and kW demand weather normalization adjustments; and total adjusted data.

Schedule II-H-4.2: Revenue Calculation Methodologies – This schedule provides narrative descriptions of the methodologies used to calculate the adjustments to revenues.

Schedule II-H-5.1: Weather Station Data – This schedule provides actual and normal Heating Degree Days ("HDD") and Cooling Degree Days ("CDD") for each of the ten National Oceanic and Atmospheric Administration ("NOAA") weather stations used in the weather normalization analysis for the twenty-year period analyzed. As explained later in my testimony, actual and normal HDD and CDD are calculated for different temperature bases for each modeled class.

Schedule II-H-5.2: Adjusted Weather Station Data – This schedule provides the same information provided in Schedule II-H-5.1 after system weighting and adjusting for billing-cycles. The schedule also provides the calculation of the weighted average system actual and normal HDD and CDD for each class for which weather normalization models were developed. In addition, this schedule provides example calculations that describe the process by which actual and normal HDD and CDD by billing cycle were summarized to develop monthly degree days. Finally, Schedule II-H-5.2 provides the spline weights by class that are used to derive the spline-weighted degree days employed in the final regression models.

Schedule II-H-5.3: Additional Weather Information – This schedule provides base 65° HDD by site prior to billing cycle adjustments and system weighted degree days after billing cycle adjustments. Base 65° CDD by site are included in response to Schedule II-H-5.1.

Schedule IV-J-4A: Load Research Data – This schedule provides the following monthly load research information: kW demands at the times of the ERCOT system peak, kW demands at the times of the Oncor system peak, class peak demands, and customer non-coincident peak demands at

the meter for the rate classes that have 100% interval data recorders ("IDR").

Schedule IV-J-4B: Load Research Data – This schedule provides test-year load research statistics by class and stratum for each rate class that requires a load research sampling methodology. This schedule also provides frequency distributions of the number of bills based on kWh or kW by month by rate class.

Schedule IV-J-4C: Load Research Data – This schedule provides a narrative description of the methodology used to estimate the class demands for the lighting service rate class.

Schedule IV-J-5: Billing Determinants – This schedule provides billed kW demand, kWh sales, number of customers, and the appropriate adjustments for billing by rate class by month.

Schedule IV-J-8: Rate Design Analysis Data – This schedule provides test-year monthly on-peak and off-peak demand and energy for the rate classes that have 100% IDRs.

Q. HOW DOES ONCOR USE THE LOAD RESEARCH DATA PRESENTED IN SEVERAL OF THE SCHEDULES THAT YOU MENTION ABOVE?

A. Oncor's load research data provides the basis for the demand data used in the cost allocation processes. Rate class demand data was developed in conjunction with the Company's continuing program of load research. All metered rate classes have 100% of the customers equipped with meters capable of interval demand data (*i.e.*, traditional IDRs or advanced meters), and as a result, the class demand for each class is determined by summing the demands of each customer in the class.

Q. WHY IS IT IMPORTANT THAT THE COMMISSION APPROVE THE ADJUSTMENTS DESCRIBED IN YOUR TESTIMONY?

A. The adjustments described in my testimony account for various abnormalities that were experienced during the test year in order to provide a normalized test year. If these adjustments are not approved, then the test

year will not be reflective of a normal year, and Oncor could potentially over recover or under recover its cost of service.

Q. WERE YOUR DIRECT TESTIMONY AND EXHIBIT PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes. My direct testimony and the exhibit to my testimony were prepared by me or under my direction, supervision, or control and are true and correct.

III. ADJUSTMENTS TO HISTORIC TEST YEAR DATA

Q. WHAT TYPES OF ADJUSTMENTS HAVE YOU MADE TO THE HISTORIC TEST YEAR DATA?

A. I have made adjustments to test year energy, demands, and number of customers in each rate class to account for the number of customers at the end of the test year. In addition, I have made adjustments to test year energy and demands to account for weather normalization and the application of the demand ratchet and power factor provisions of Oncor's Tariff for Retail Delivery Service. Schedule II-H-1.1 provides a test-year summary of these adjustments. Schedule II-H-1.2 provides a month-by-month summary of the adjustments to kWh sales to reflect customer growth and weather normalization adjustments.

Q. WHAT WAS THE SOURCE OF THE UNADJUSTED DATA YOU HAVE EMPLOYED?

A. The per book (or unadjusted) number of customers, energy sales, and revenues were provided to me by Company witness Mr. W. Alan Ledbetter, who supports the accuracy of the Company's books and records in his direct testimony.

A. Adjustments to Reflect Customer Growth

Q. DOES THE COMPANY NORMALLY MAKE THE TYPE OF CUSTOMER ADJUSTMENTS THAT IT PROPOSES IN THIS RATE CASE?

A. Yes. Oncor, as well as other Texas utilities, typically make the type of customer adjustments proposed in this case. Oncor used the same methodology for customer adjustments that I propose here in its most recent

rate case (Docket No. 46957) and in two prior rate cases (Docket Nos. 38929 and 35717). The customer adjustments proposed by Oncor in those cases were incorporated into the rates approved by the Commission.

Q. WHAT ADJUSTMENTS DID YOU MAKE TO THE NUMBER OF CUSTOMERS IN THIS CASE?

A. For each retail class of service, the number of customers during each month of the test year was adjusted to reflect the December 31, 2021 level of customers. The customer adjustments reflect the growth or decline in the number of customers by rate class from the actual monthly levels occurring during the test year to the number of customers receiving service at the end of the test year.

Q. WHY HAS THE COMPANY MADE ADJUSTMENTS TO ANNUALIZE THE GROWTH OR DECLINE IN THE NUMBER OF CUSTOMERS BY CLASS OF SERVICE TO TEST YEAR-END LEVELS?

A. By adjusting customers to reflect changes in the number of customers occurring during the test year, revenues related to changes in the number of customers are presented at a level that more accurately depicts the anticipated customers, usage and revenues during the period in which rates will be in effect.

Q. PLEASE EXPLAIN HOW YOU ADJUSTED ENERGY, DEMANDS, AND REVENUES FOR CHANGES IN THE NUMBER OF CUSTOMERS IN EACH CLASS.

A. Customer adjustments were made to the number of customers, energy sales, kW demands, billing demands, and revenues. Narrative descriptions of the calculation of the customer adjustments are provided on Schedule II-H-3.2. Schedule II-H-3.2 also provides sample calculations of the kWh and kW adjustments for customer growth. Workpapers WP/II-H-4.1 and WP/IV-J-5 provide detailed calculations of the adjustments. The adjustment to reflect the change in the number of customers was applied to weather adjusted sales volumes, as calculated on Schedules II-H-2.1 through II-H-

2.3 and II-H-5.1 through II-H-5.3 to determine sales after adjustments for weather and test year-end level of customers. Once total adjusted class sales were determined, the adjusted number of customers, demands, and energy sales were used to restate present revenues. Schedule II-H-4.2 provides a narrative description of the methodology used to calculate the revenue adjustments resulting from customer annualization, weather normalization, demand ratchet and power factor annualization.

Q. WHAT IS THE EFFECT OF THE CUSTOMER GROWTH ADJUSTMENT ON KWH SALES?

A. The total customer growth adjustment to retail kWh sales is an increase of 1,776,817,682 kWh in test-year sales. This adjustment is presented by rate class on an annual basis on Schedule II-H-1.1 and by class and month on Schedule II-H-1.2.

Q. HAVE YOU MADE A CUSTOMER ADJUSTMENT FOR WHOLESALE CUSTOMERS?

A. Yes, I have.

Q. PLEASE DESCRIBE THE CUSTOMER ADJUSTMENT MADE TO THE WHOLESALE CLASSES.

A. The customer adjustment to the Wholesale-DLS rate class reflects the loss of one point of interconnection in June 2021 and the addition of two service points of interconnection in July 2021. The customer adjustment to the Wholesale-XFMR rate class reflects the addition of one point of service in July 2021. The appropriate monthly demands and energy for the period January 2021 through December 2021 were adjusted in these classes to provide the test year-end wholesale customers on Schedule II-H-1.2 pages 14 and 15 of 15. Information regarding this adjustment is provided on workpaper WP/IV-J-5, pages 14 and 15 of 16. Adjustments were not made to reflect increases or decreases in the number of end-use consumers receiving service beyond the wholesale points of interconnection since the

Company does not have access to this information, and any such adjustments would not be reasonably known or measurable.

B. Adjustments to Reflect Weather Normalization

Q. HAS THE COMMISSION PREVIOUSLY APPROVED THE WEATHER NORMALIZATION METHOD PROPOSED BY ONCOR IN THIS RATE CASE?

A. Yes. In Docket No. 35717, the Commission approved the same methodology for weather normalization that I propose here. *See* Order on Rehearing, Finding of Fact No. 185. In addition, Oncor's two most recent rate cases, Docket Nos. 46957 and 38929, used the same methodology to normalize weather as in Docket No. 35717.

Q. WHY HAS THE COMPANY MADE WEATHER NORMALIZATION ADJUSTMENTS TO THE ENERGY AND DEMANDS OF THE VARIOUS RATE CLASSES?

A. Kilowatt-hour sales were adjusted to normalize test year sales for those rate classes whose use of electricity is affected by temperature conditions. Typically, kWh sales fluctuate as the use of electric heating and air-conditioning increases and decreases due to temperature fluctuations. Warmer than normal temperatures during air-conditioning months result in higher than normal sales of electricity, while cooler than normal temperatures result in lower than normal sales. Similarly, cooler than normal temperatures during space heating months result in higher than normal sales of electricity, while warmer than normal temperatures result in lower than normal sales. During any given period, temperature conditions may be warmer or colder than normally occur, and as a result, sales of electricity may be higher or lower than the level that will normally occur.

In a rate case filing, adjustments for such abnormal temperature conditions must be made in order to ensure that the kWh sales levels upon which rates are based do not over-recover or under-recover the utility's allowed cost of service. The test year energy sales and kW loads of these

temperature sensitive rate classes are used as the basis for setting rates on an on-going basis. These classes' sales and loads will be overstated or understated depending upon whether temperatures during the test year were higher or lower than normal. Unbiased ratemaking requires the adjustment of test-year kWh deliveries to a level that would have occurred under normal, or average, weather conditions. Therefore, it is necessary to adjust, or normalize, test-year sales and loads so that this information is neither understated nor overstated.

Q. HOW WERE THE COMPANY'S WEATHER NORMALIZATION ADJUSTMENTS MADE?

A. As typically done in cases before the Commission, we prepared statistical models that measure customers' responsiveness to temperatures. These models show that the Company's kWh deliveries are heavily influenced by fluctuations in the weather. The coefficients of the weather variables in these models were used to estimate the responsiveness of customers to changes in temperature. In this case, weather normalization models have been prepared for five classes of customers:

- Residential;
- Secondary Service Less Than or Equal to 10 kW;
- Secondary Service Greater than 10 kW;
- Primary Service Greater Than 10 kW – Distribution Line; and
- Primary Service Greater Than 10 kW – Substation.

For the Secondary Service Greater Than 10 kW model and the Primary Service Greater Than 10 kW – Distribution Line model, the weather normalization adjustments produced by these models were allocated to "sub-groups" within the class (*i.e.*, IDR and Non-IDR) as shown on workpaper WP/II-H-1.2/1, pages 5 and 7.

The analyses of these five customer classes showed that weather normalization adjustments were not appropriate. First, a weather normalization model was produced for the Transmission Service class, but

the model showed that this class did not have statistically significant weather response variables. Thus, no weather normalization adjustment is proposed for this class. Second, graphical analysis showed that customers in the Primary Service Less Than or Equal to 10 kW class are not weather sensitive. Therefore, no weather adjustment is proposed for this class. Third, there was no weather adjustment to the lighting class, as weather does not affecting lighting hours. Finally, no weather normalization adjustment is proposed for two wholesale classes since the Company does not have access to end-user information for the customers of wholesale systems and the temperature conditions of the wholesale service areas are not necessarily the same as the Company's.

Q. HAS THE COMMISSION PREVIOUSLY RECOGNIZED THE NEED TO MAKE WEATHER NORMALIZATION ADJUSTMENTS?

A. Yes, the Commission has accepted weather normalization adjustments in numerous cases filed by the Company as well as by other electric utilities in Texas, including Oncor's most recent rate case, Docket No. 46957.

Q. WHAT IS THE EFFECT OF THE WEATHER ADJUSTMENT ON KWH SALES?

A. Overall, the weather during the test year was milder than normal, and the magnitude of the weather normalization adjustment is moderate. The total weather adjustment to kWh is an increase of 1,413,717,519 kWh (1.0%) from unadjusted test year sales levels. This adjustment is shown in column (d) on Schedule II-H-1.1 and is presented by month and rate class on Schedule II-H-1.2.

Q. HOW DID YOU EVALUATE WEATHER FOR PURPOSES OF THIS ADJUSTMENT?

A. My evaluation of weather and its associated effect upon electricity sales uses temperature information expressed in relation to a reference temperature. In this case, as in most cases, the measure used to quantify the relation of temperature to a reference temperature is known as a

"degree day." Fluctuations in daily average temperature below the designated base temperature tend to require the use of heating appliances, and are measured as HDD. Conversely, fluctuations in daily average temperature above a designated base temperature tend to require the use of air conditioning and are measured as CDD. Both CDD and HDD values were set to zero whenever the calculation yielded a negative value.

Q. PLEASE SUMMARIZE THE PROCESS BY WHICH CLASS WEATHER NORMALIZATION ADJUSTMENTS WERE CALCULATED.

A. Weather normalization adjustments were calculated in a six step process. The first four steps develop the weather adjustment coefficients, which are the measures of weather responsiveness used in making the weather normalization adjustments. The final two steps calculate normal CDD and HDD and develop the proposed weather normalization adjustments by class.

In the first step, daily temperatures from locations across Oncor's service area were used to calculate CDD and HDD by location and then combined to obtain total system CDD and HDD by rate class. Second, degree days were used along with daily load research data to develop class weather models having multiple temperature bases. Third, daily degree days from the first step were billing cycle adjusted and spline weighted to develop the specific monthly weather measures to use in the weather normalization regressions. Spline weights are developed from the results of class weather model in step 2. Fourth, weather models by class were developed using spline weighted CDD and HDD from the prior step along with other explanatory variables including indices of household size, household income, inflation adjusted electricity prices, and appliance saturations and efficiencies. In the fifth step, normal degree days were developed using a 20-year average from 2001 through 2020. In the final step, the regression coefficients of the CDD and HDD variables for each of the final weather models were used to quantify monthly weather

normalization adjustments by class. The monthly weather adjustments for Secondary Service Greater Than 10 kW and Primary Service Greater Than 10 kW – Distribution Line were further allocated between the IDR and non-IDR sub-groups that comprise these more broadly modeled classes.

Q. HAVE YOU DETERMINED THE REASONABLENESS OF THE WEATHER ADJUSTMENTS PROPOSED BY ONCOR IN THIS CASE?

A. Yes. I have reviewed the regressions, the weather data, the calculation of the weather normalization adjustments, and other data and calculations and have found the weather adjustments to be reasonable and accurate.

C. Adjustments to Reflect Customer Responses to Power Factor

Q. HAS ONCOR ADJUSTED POWER FACTOR BILLED KW TO REFLECT KNOWN AND MEASURABLE CHANGES TO POWER FACTOR DEMANDS?

A. Yes, Oncor has adjusted power factor billed kW to reflect known and measurable changes to customers' test year power factors.

Q. HAS THE COMMISSION PREVIOUSLY APPROVED THE POWER FACTOR ADJUSTMENT METHOD PROPOSED BY ONCOR IN THIS RATE CASE?

A. Yes. In Docket No. 35717, the Commission approved the same methodology for power factor adjustment as I propose here. *See* Order on Rehearing, Finding of Fact No. 188. In addition, Oncor's two most recent rate cases, Docket Nos. 46957 and 38929, used the same power factor adjustment methodology as in Docket No. 35717.

Q. PLEASE SUMMARIZE THE ADJUSTMENTS TO BILLING DEMANDS AND DEMAND REVENUE THAT WERE MADE TO REFLECT CUSTOMER RESPONSES TO THE POWER FACTOR PROVISIONS SET FORTH IN THE COMPANY'S TARIFF.

A. Oncor proposes to adjust the billing demands and demand revenues of Secondary Service Greater than 10 kW, Primary Service Greater than 10 kW – Substation, Primary Service Greater than 10 kW – Distribution Line,

and Transmission Service customers to reflect their known and measurable responses to the application of the power factor provision set forth in Section 5.5.5 of the Company's Tariff for Retail Delivery Service. The power factor provisions in the Company's Tariff provide for increasing customer billing demands for customers whose power factors are less than 95 percent lagging. As described below, the proposed billing demand adjustment is made to reflect customers' changes in load characteristics resulting from their adaptation to the power factor charges.

When faced with increased demand charges resulting from the application of the power factor adjustment, customers respond by installing the necessary equipment at their service locations to correct the lower power factors they impose on the delivery system. The billing demands for these customers who respond to the power factor adjustment decreased from the levels initially experienced as a result of applying the power factor provision. This response is not surprising because the purpose of the power factor provision is to provide customers an incentive to correct lagging power factors. This resulting decrease in demands is a reasonable and anticipated customer response to the price signals of the power factor provision.

The proposed adjustment to billing demands reflects these known and measurable changes in power factor billing demands and the associated revenue effects. I have quantified the reductions in distribution billing demands and revenues to reflect the measurable improvement in power factors of customers during the test year for the rate classes that are subject to the provisions of the power factor adjustment. If the Company is unable to properly adjust for this power factor improvement, demand billing units will be overstated, which will produce a lower rate than appropriate. Therefore, in the proposed rates, revenue will not achieve the Commission-authorized levels. By removing these nonrecurring billing demands, the

proposed rates will more accurately reflect the on-going level of billing demands.

Q. HOW DID ONCOR CALCULATE THE PROPOSED POWER FACTOR DEMAND ADJUSTMENTS?

A. The proposed power factor demand adjustments have been made using the method previously approved by the Commission in Docket No. 35717 and relied upon in the stipulation adopted in Docket Nos. 46957 and 38929. The derivation of the power factor adjustments to distribution billing demands by month by class are provided on WP/IV-J-5, pages 2, 4, 6, 8, 10 and 12. Oncor undertook a comprehensive analysis of each customer that had a power factor adjustment applied to it during the test year. For each customer, the Company determined the percentage of monthly billing demands, including the related ratcheted demands, which resulted from the application of the power factor. The ratios of billing demands prior to the application of the power factor to billing demands after application of the power factor were calculated and are shown in column (d) of WP/IV-J-5, pages 2, 4, 6, 8, 10 and 12.

Customers respond to the application of the power factor adjustment by taking some form of action to correct their lagging power factor. As a result, customers' power factors improved over the course of the test period. Once a customer achieved a power factor of 95 percent or greater during any month of the test year, the analysis recognized that the customer exhibited the ability to achieve the same high power factor in subsequent months. By the end of the test period, the impact of the power factor adjustment decreased as additional customers took the necessary corrective actions to eliminate or reduce their reactive power.

Q. HOW WERE THE ADJUSTED POWER FACTOR REVENUES TAKEN INTO ACCOUNT IN THE DESIGN OF THE PROPOSED RATES?

A. The Company employed the same method to adjust power factor revenue in this filing as used in Docket No. 35717 and Docket Nos. 46957 and

38929. The adjustment employed a three-step procedure to take power factor revenue into account in the design of proposed rates. In the first step, adjusted power factor revenues were removed from base rates and treated as Power Factor Revenues. Adjusted present revenues produced by the application of the power factor provision were developed on workpaper WP/IV-J-5, page 16, line 20. Total power factor revenue was removed from base rate revenue and included in Power Factor Revenues as set forth on pages 2 through 9 of Schedule II-H-4.1, line 25, column (j).

In the second step, power factor revenues at proposed rates were developed. This step is necessary to restate power factor revenues at proposed rates. In this step, the proposed power factor revenues are the product of power factor adjusted billing demands multiplied by the proposed demand charges of the affected classes. Distribution power factor revenue by class at proposed rates was developed on workpaper WP/IV-J-7/1, page 13, by multiplying the adjusted power factor revenue for each class at present rates by the percentage increase proposed for that class.

In the third step, class base rate revenues were reduced by deducting Other Revenues, which include power factor adjustment revenue, from each class' revenue requirement. This step necessitates the allocation of power factor adjustment revenues to each class as described in Company witness Mr. Matthew A. Troxle's direct testimony. In this manner, all of Oncor's customers benefit through reduced base rate charges.

IV. CONCLUSION

Q PLEASE SUMMARIZE YOUR DIRECT TESTIMONY.

A. My direct testimony demonstrates that the adjustments to customers, energy sales, load and billing demands, and revenues that were made to reflect the effects of changes in the test year number of customers, weather effects, and effects of the power factor provision are reasonable and

necessary to reflect the usage characteristics and applicable rates of affected customers.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

STATE OF TEXAS §
§
COUNTY OF DALLAS §

BEFORE ME, the undersigned authority, on this day personally appeared Darryl E. Nelson, who, having been placed under oath by me, did depose as follows:

My name is Darryl E. Nelson. I am of legal age and a resident of the State of Texas. The foregoing direct testimony and the attached exhibit offered by me are true and correct, and the opinions stated therein are accurate, true and correct.

Darryl E. Nelson

SUBSCRIBED AND SWORN TO BEFORE ME by said Darryl E. Nelson this 12th day of April, 2022.

MICHELE M. GIBSON
Notary Public, State of Texas
Comm. Expires 06-30-2022
Notary ID 575631-8

Notary Public, State of Texas

FILING PACKAGE SCHEDULES

Darryl E. Nelson

SCHEDULE	SPONSOR	TITLE OF SCHEDULE
II-H-1.1	Nelson	Test Year Sales Data
II-H-1.1.1	Nelson	Test Year Energy Flows Across DC Ties
II-H-1.2	Nelson	Monthly Sales Data
II-H-1.3	Nelson	Unadjusted Test Year Load Data
II-H-1.3.1	Nelson	Adjustments to Test Year Load Data
II-H-1.3.2	Nelson	DC Tie Load Data
II-H-1.4	Nelson	Adjusted Test Year Load Data
II-H-1.5	Nelson	Adjustments to Operating Statistics
II-H-2.1	Nelson	Model Information
II-H-2.2	Nelson	Model Data
II-H-2.3	Nelson	Model Variables
II-H-3.1	Nelson	Customer Information
II-H-3.2	Nelson	Customer Adjustments
II-H-3.3	Nelson	Customer Adjustment Data
II-H-4.1	Nelson	Revenue Impact Data
II-H-4.2	Nelson	Revenue Calculation Methodologies
II-H-5.1	Nelson	Weather Station Data
II-H-5.2	Nelson	Adjusted Weather Station Data
II-H-5.3	Nelson	Additional Weather Information
IV-J-4A	Nelson	Load Research Data
IV-J-4B	Nelson	Load Research Data
IV-J-4C	Nelson	Load Research Data
IV-J-5	Nelson	Billing Determinants
IV-J-8	Nelson	Rate Design Analysis Data

2022 RATE CASE
ONCOR ELECTRIC DELIVERY COMPANY LLC
WORKPAPERS FOR
THE DIRECT TESTIMONY OF
DARRYL E. NELSON

Mr. Nelson has no supporting workpapers for his direct testimony.

INDEX TO THE DIRECT TESTIMONY
OF ROBERT A. SCHMIDT, WITNESS FOR
ONCOR ELECTRIC DELIVERY COMPANY LLC

DIRECT TESTIMONY OF ROBERT A. SCHMIDT

I. POSITION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Robert A. Schmidt. My business address is 1616 Woodall Rodgers, Dallas, Texas 75202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Oncor Electric Delivery Company LLC ("Company" or "Oncor") in the Regulatory Financial Department as a Regulatory Manager.

Q. PLEASE OUTLINE YOUR EDUCATIONAL AND PROFESSIONAL QUALIFICATIONS.

A. I received a Bachelor of Business Administration degree in Accounting from Texas Tech University in 1982. In 1985, I was licensed as a Certified Public Accountant in the State of Texas. I am a member of the American Institute of Certified Public Accountants and the Texas Society of Certified Public Accountants. In 1982, I began my service in the Texas Utilities System at Texas Electric Service Company upon graduation from Texas Tech University. From 1982 through 1991, I worked in various areas of the company, including Financial Systems, General Accounting, Internal Audit, and Regulatory. I was a member of the Company's rate-case expense team in Public Utility Commission of Texas ("Commission") Docket No. 9300, with responsibility for auditing the rate-case expenses associated with the general aspects of the rate case as well as the nuclear plant prudence review for Comanche Peak Unit 1. In January 1992, I transferred to the TU Electric Rates and Regulation function as a Senior Internal Auditor with responsibility for the rate-case expense phase of TU Electric's Docket No. 11735 at the Commission. My responsibilities included auditing the rate-case expenses associated with the general aspects of the rate case as well as the nuclear plant prudence review for Comanche Peak Unit 2. I provided testimony on the reasonableness and

necessity of Docket No. 11735 rate-case expenses. In December 1993, I transferred to Texas Utilities Services Inc. as a Senior Financial Analyst in the Financial Planning Department, where I conducted a variety of financial analyses for the Texas Utilities System. I joined the Transmission Division of TU Electric as Rates and Cost Analysis Manager in March 1996. In July 2004, I joined Oncor's Regulatory organization in my present capacity. I was the Company's rate-case expense witness in Docket Nos. 35717, 38929, and 46957, with responsibility for the monitoring, review, and audit of Company rate-case expenses and providing testimony on the reasonableness and necessity of those rate-case expenses.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE COMMISSION?

A. Yes. I sponsored direct, supplemental direct, and rebuttal testimony in Commission Docket No. 11735. I sponsored direct, supplemental direct, and rebuttal testimony in Docket No. 15638. I sponsored direct testimony in Commission Docket No. 17285. I sponsored direct, supplemental direct, and rebuttal testimony in Docket No. 22350. I sponsored direct and rebuttal testimony in Docket No. 22344. I sponsored direct testimony in Oncor's Docket No. 35717 rate case, and supplemental direct testimony in Docket No. 36530, Oncor's rate-case expense docket related to Docket No. 35717. I sponsored direct testimony in Oncor's Docket No. 38929 rate case, and supplemental direct testimony in Docket No. 39239, Oncor's rate-case expense docket related to Docket No. 38929. I sponsored direct testimony in Oncor's most recent base-rate case, Docket No. 46957.

II. PURPOSE OF DIRECT TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my direct testimony is to support the reasonableness and necessity of Oncor's requested rate-case expenses in this proceeding. I

will describe the processes used to control and verify rate-case expenses and the steps taken to ensure that the expenses requested are reasonable and necessary for the litigation of this case.

Q. ARE YOU SPONSORING ANY RATE FILING PACKAGE SCHEDULES?

A. Yes, I am co-sponsoring, with Company witness Mr. W. Alan Ledbetter, Rate Filing Package Schedule II-E-4.5, Rate-Case Expenses.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I sponsor Exhibits RAS-1 and RAS-2, both of which are submitted with my direct testimony. My direct testimony, exhibits, and Rate Filing Package Schedule II-E-4.5, which I co-sponsor with Mr. Ledbetter, were prepared by me or under my direction, supervision, or control and are, to the best of my knowledge and belief, true and correct.

III. RATE-CASE EXPENSES

Q. WHAT IS THE SCOPE OF RATE-CASE EXPENSES REQUESTED IN THIS PROCEEDING?

A. Oncor is requesting the recovery of actual rate-case expenses related to Docket No. 46957 that were incurred subsequent to the May 31, 2017 cutoff established in that docket, actual rate-case expenses related to its first two and its fourth distribution cost recovery factor ("DCRF") cases (Docket Nos. 48231, 49427, and 51966), actual rate-case expenses related to its Tax Cuts and Jobs Act ("TCJA") Tax case (Docket No. 48325), actual rate-case expenses related to its advanced metering system ("AMS") final reconciliation case (Docket No. 49721), and is providing an estimate of expenses to be incurred to litigate the instant case. In Oncor's third DCRF case, Docket No. 50734, Oncor agreed not to seek recovery of its rate-case expenses for that rate proceeding. PURA § 36.061(b)(2) provides the statutory authority for the inclusion of rate-case expense as an allowable expense. In addition, 16 Tex. Admin. Code § 25.245, Rate-Case Expenses, applies to utilities requesting recovery of expenses for ratemaking proceedings.

The October 13, 2017 Order in Docket No. 46957 includes the following language in Ordering Paragraph No. 8:

> Rate-case expenses associated with this proceeding incurred after May 31, 2017 shall be captured in a regulatory asset and reviewed in Oncor's next general base-rate case.

The August 30, 2018 Order in Docket No. 48231 includes the following language in Ordering Paragraph No. 4:

> Oncor may request recovery of its and any participating municipality's rate-case expenses incurred in this proceeding in a future rate proceeding, or Oncor may request to collect those expenses through a separate surcharge. Any rate-case expenses in connection with this proceeding will be subject to a final determination by the Commission as to the reasonableness and necessity of those expenses.

The September 12, 2019 Order in Docket No. 49427 includes the following language in Ordering Paragraph No. 6:

> Oncor may request recovery of its and any participating municipality's rate-case expenses incurred in this proceeding in a future rate proceeding, or Oncor may request to collect those expenses through a separate surcharge. Any rate-case expenses in connection with this proceeding will be subject to a final determination by the Commission as to the reasonableness and necessity of those expenses.

The April 4, 2019 Order in Docket No. 48325 includes the following language in Ordering Paragraph No. 13:

> Oncor may establish a regulatory asset for rate-case expenses in this docket that Oncor incurs and that are incurred by and reimbursed to participating municipalities.

The December 16, 2019 Order in Docket No. 49721 includes the following language in Ordering Paragraph No. 3:

> Oncor must record the costs of this reconciliation as a regulatory asset, and those costs must be reviewed in Oncor's next base-rate case.

The July 30, 2021 Order in Docket No. 51996 includes the following language in Ordering Paragraph No. 6:

> Oncor is authorized to either request recovery of its own and any participating municipality's rate-case expenses incurred

in this proceeding in a future rate proceeding, or to request to collect those expenses through a separate surcharge. Any rate-case expenses in connection with this proceeding are subject to a final determination by the Commission as to the reasonableness and necessity of those expenses.

I have included rate-case expenses of participating municipalities in Oncor's requested rate-case expenses. Rate-case expenses reimbursed to The Alliance of Oncor Cities ("AOC") have been included for Docket Nos. 46957, 48231, 48325, 49427, and 51996. Rate-case expenses reimbursed to the Steering Committee of Cities Served by Oncor ("Cities") have been included for Docket Nos. 46957, 48231, 48325, 49427, and 51996. Rate-case expenses reimbursed to the City of Mission have been included for Docket Nos. 48231 and 48325. See Exhibits RAS-1 and RAS-2.

In order to litigate the instant case, Oncor will incur various legal and consulting costs, as well as incremental internal costs, such as rate filing package printing, document shipping costs, transcripts of hearings, employee travel expenses, and newspaper public notices.

Q. WHAT AMOUNT OF RATE-CASE EXPENSE IS ONCOR REQUESTING?

A. Oncor is requesting recovery of $331,994.46 for the Docket No. 46957 post-cutoff rate-case expenses, $304,615.99 for the Docket No. 48231 DCRF rate-case expenses, $167,728.14 for the Docket No. 49427 DCRF rate-case expenses, $334,785.03 for the Docket No. 48325 TCJA case rate-case expenses, $178,482.85 for the Docket No. 49721 AMS reconciliation rate-case expenses, $215,521.46 for the Docket No. 51996 DCRF rate-case expenses, and an estimate of $6,700,000 for expenses to be incurred in this December 2021 test year case, for a total of $8,233,127.93.

The $331,994.46 for the Docket No. 46957 post-cutoff rate-case expenses includes costs that were incurred to complete the settlement of that case. This amount also includes a reduction of $254,178.24, which is the balance of a regulatory liability for the Docket No. 46957 Rider RCE

amounts collected in excess of the amount stated in the Rider RCE tariff sheet. Mr. Ledbetter's testimony includes additional information about this regulatory liability. The amounts listed above for Docket Nos. 48231, 49427, 48325, 49721, and 51996 are the total rate-case expenses incurred for the litigation of those respective cases.

The $6.7 million estimate for the instant case includes an estimate of $700,000 for intervenor expenses. My Exhibit RAS-1 summarizes these expenses, and my Exhibit RAS-2 provides a more detailed listing of expenses for the various dockets and the estimates for the instant case by firm and category of expense. Consistent with prior Commission practice in rate cases, I anticipate that supplemental testimony along with supporting documentation for actual rate-case expenses will be submitted later in the case. This additional testimony and supporting documentation will replace the currently provided $6.7 million estimate of rate-case expenses for this case with actual expenses.

IV. RECOVERY, AMORTIZATION, AND FUNCTIONALIZATION

Q. HOW DOES ONCOR PROPOSE TO RECOVER THE REQUESTED RATE-CASE EXPENSES?

A. Oncor proposes to amortize the requested rate-case expenses of $8,233,127.93 over a five-year period, with an annual amortization amount of $1,646,625.59. Please see the direct testimony of Company witness Mr. W. Alan Ledbetter for further information on requested amortization periods. Recovery of rate-case expenses is proposed through a rate-case expense surcharge rider. Please see the direct testimony of Company witness Mr. Matthew A. Troxle for further information on the proposed recovery of rate-case expenses.

Q. HOW ARE THE REQUESTED RATE-CASE EXPENSES BEING ASSIGNED TO THE VARIOUS FUNCTIONS?

A. Please refer to Rate Filing Package Schedule II-E-4.5. I am supporting the total requested rate-case expenses, and Company witness Mr. Ledbetter is supporting the functionalization of the rate-case expenses.

V. SELECTION OF RESOURCES

Q. HOW ARE LEGAL AND CONSULTING RESOURCES SELECTED?

A. In order to litigate a case of this magnitude, Oncor must supplement its internal legal and technical expertise and resources with additional resources. Based on the various areas to be covered in the case and the anticipated workload, Oncor has selected outside legal and consulting resources needed to effectively litigate the case. The Company selects these resources based on the specialized skills and expertise, past experience, and the reputation and credibility of the individuals and firms. See also the direct testimony of Company witness Ms. Andrea M. Stover regarding Oncor's selection of legal and consulting resources.

Q. HAS ONCOR USED A COMPETITIVE BIDDING PROCESS TO SELECT LEGAL AND CONSULTING RESOURCES?

A. No. Due to the specialized nature of the skills and expertise needed, competitive bidding is not customarily used to select the legal and consulting resources necessary to litigate a rate case. In addition, the precise scope of work is often difficult to estimate due to the many variables involved in rate case litigation, such as the amount of discovery and the length of the procedural schedule.

VI. CONTROLS OVER RATE-CASE EXPENSES

Q. PLEASE DESCRIBE ONCOR'S RATE CASE OVERSIGHT RESPONSIBILITIES.

A. Matthew C. Henry, Oncor's Senior Vice President, General Counsel, and Secretary, has overall responsibility for management of the case. J. Michael Sherburne, Oncor's Vice President – Regulatory, is the designated case manager. Various other personnel in the Company's

Regulatory organization have been assigned responsibilities for specific aspects of the case.

Q. PLEASE DESCRIBE HOW ONCOR MANAGES THE LEVEL OF RATE CASE RESOURCES.

A. For each subject area of the case, teams consisting of a witness (internal or external), Oncor personnel, and a lead attorney have been established. These teams are responsible for the preparation of testimony and rate filing package schedules for their assigned subject area. Later in the case, these teams will respond to discovery, participate in hearings on the merits, and provide research and analysis for the briefing process and preparation of exceptions and replies to exceptions to the proposal for decision. These teams continually monitor the workload in their area of the case and adjust the level of outside legal and consulting resources necessary to address the workload in a timely manner.

Q. PLEASE EXPLAIN THE INVOICE REVIEW AND APPROVAL PROCESS FOR RATE-CASE EXPENSES.

A. Rate case invoices are subjected to a review and approval process coordinated by me, with assistance of other members of the Regulatory Financial Department. Invoices that are appropriately included in rate-case expense are charged to a deferred debit account with a specific project code, so that rate-case expenses are properly segregated from other expenses.

After rate case invoices are received, the rate-case expense team (including members of the Regulatory Financial Department and me) performs an invoice audit. This invoice audit is thorough and includes verification of hourly rates, review of the number of hours billed and the description of work, mathematical accuracy of the invoice, and the inclusion of required supporting documentation, such as travel expense receipts. The invoices are then routed to the appropriate subject area team for verification and approval of the number of hours billed. After this

review and approval process, the invoice is processed through Oncor's Accounts Payable processes for final validation and payment.

VII. REASONABLENESS OF FEES AND HOURLY RATES

Q. HOW HAVE YOU DETERMINED THAT ONCOR'S LEGAL AND CONSULTING FEES ARE REASONABLE?

A. I have examined the hourly rates for the legal and consulting resources employed in this case and compared them to hourly rates billed in other recent cases (such as the CenterPoint Energy Houston Electric, LLC, AEP Texas, Inc., and Southwestern Public Service Company rate cases). I have also researched hourly billing rates for legal and consulting services from sources such as Lawyers.com, Law.com, and *The National Law Journal* publications. I have concluded that the hourly rates billed for legal and consulting services in this case are comparable to the rates billed in other recent rate cases and to the rates reflected in various surveys for similar, specialized skills. Thus, the hourly rates billed for legal and consulting resources in this case are reasonable. In addition, the direct testimony of Company witness Ms. Stover addresses the reasonableness of legal and consulting fees, as well as the reasonableness of the level of rate case resources employed.

VIII. REASONABLENESS AND NECESSITY OF EXPENSES

Q. HOW HAVE YOU DETERMINED THE REASONABLENESS AND NECESSITY OF THE REQUESTED RATE-CASE EXPENSES?

A. In order to meet its burden of proof, Oncor must present substantial information on a wide variety of complex issues. The justification of the cost of service and the rates requested necessitates a thorough, coordinated effort. The Company takes steps to manage, monitor, and control rate-case expenses, and this process is designed to ensure that the requested expenses are both reasonable and necessary.

Q. PLEASE COMMENT ON THE SCOPE OF INFORMATION NECESSARY TO PRESENT A RATE CASE.

A. The rate filing package for a transmission and distribution base-rate case requires a large number of schedules, testimony to support expenses and capital costs requested, detailed supporting workpapers, and in some instances, studies to support requested treatment of a specific issue. In addition, the new rate filing package requirements, adopted by the Commission in Project No. 49199 in July 2020, have increased the amount of data that must be researched and presented as part of the rate filing package. The amount of time required to research and analyze the underlying data and develop studies and testimony is substantial. Oncor has taken steps to present a thorough case, while managing the effort to ensure that rate-case expenses are reasonable and necessary.

Q. WHAT WOULD THE IMPACT OR CONSEQUENCES BE IF ONCOR'S REQUEST FOR RATE-CASE EXPENSE RECOVERY WERE TO BE DENIED?

A. If Oncor's request for rate-case expense recovery were to be denied, Oncor would have to write off the full amount of the requested $8.2 million. Such an outcome is clearly inappropriate, as Oncor is entitled to recovery of its reasonable and necessary rate-case expenses.

IX. SUMMARY AND CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. Oncor has incurred approximately $1.5 million in unrecovered rate-case expenses for past cases (Docket No. 46957 post-cutoff rate-case expenses, DCRF cases, the TCJA tax case, and its AMS reconciliation case). Oncor also expects to incur $6.7 million in rate-case expenses to litigate this case. The processes that the Company uses to manage the case, monitor the resources necessary to carry out the required work, and review and approve invoices are designed to ensure that the rate-case expenses incurred are both reasonable and necessary. I have determined that these rate-case expenses are reasonable and necessary, and I have given these numbers to Company witness Mr. Ledbetter for the inclusion

of the appropriate amount of amortization and Mr. Troxle for inclusion in the proposed Rate Case Expense surcharge.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

AFFIDAVIT

STATE OF TEXAS §
§
COUNTY OF DALLAS §

BEFORE ME, the undersigned authority, on this day personally appeared Robert A. Schmidt, who, having been placed under oath by me, did depose as follows:

My name is Robert A. Schmidt. I am of legal age and a resident of the State of Texas. The foregoing direct testimony and the attached exhibits offered by me are true and correct, and the opinions stated therein are, to the best of my knowledge and belief, accurate, true and correct.

Robert A. Schmidt

SUBSCRIBED AND SWORN TO BEFORE ME by the said Robert A. Schmidt this 2nd day of May, 2022.

SAMANTHA L. ZIEGENFUSS
Notary Public, State of Texas
Comm. Expires 05-29-2023
Notary ID 13020392-9

Notary Public, State of Texas

ONCOR ELECTRIC DELIVERY COMPANY LLC
RATE CASE EXPENSES - SUMMARY

Category	Docket No. 46957 (2016 TY)	Docket No. 48325 (Tax Case)	Docket No. 48231 (DCRF)	Docket No. 49427 (DCRF)	Docket No. 49721 (AMS Rec.)	Docket No. 51996 (DCRF)	Prior Cases Subtotal	Estimate Instant Case	Total
Legal	$310,559 73	$176,676 93	$193,941.06	$94,486.40	$145,487.72	$175,386.62	$1,096,538.46	$3,800,000.00	$4,896,538 46
Consulting	33,652.50	12,390 00	7,935.00	3,079 13	0 00	0.00	$57,056 63	1,900,000.00	$1,957,056 63
Other Company Expenses (see note)	(253,695.20)	3,406.98	14,014 30	24,663.55	32,995.13	1,031.24	($177,584 00)	300,000.00	$122,416 00
Intervenor Expenses	241,477 43	142,311.12	88,725 63	45,499 06	0 00	39,103.60	557,116.84	700,000 00	1,257,116.84
Total Rate Case Expenses to Date	$331,994 46	$334,785.03	$304,615.99	$167,728.14	$178,482 85	$215,521 46	$1,533,127 93	$6,700,000.00	$8,233,127 93

Note: Docket No. 46957 expenses include a credit for the over-recovery of Docket No 46957 rate case expenses through retail Rider RCE (6.1 1 6 4) and wholesale Rider WRCE (3.5), from December 2017 through November 2018.

ONCOR ELECTRIC DELIVERY COMPANY LLC
RATE CASE EXPENSES - DETAILS

Category	Docket No. 46957 (2016 TY) After 5/31/17 Cutoff	Docket No 48325 (Tax Case)	Docket No 48231 (DCRF)	Docket No. 49427 (DCRF)	Docket No. 49721 (AMS Rec.)	Docket No. 51996 (DCRF)	Prior Cases Subtotal	Estimate Instant Case	Grand Total
Legal.									
Vinson & Elkins	310,559.73	67,675.62	173,416 90	-	145,487.72		697,139 97	1,650,000.00	2,347,139 97
Hunton Andrews Kurth		109,001 31	20,524 16	94,486 40		175,386 62	399,398 49	1,850,000.00	2,249,398.49
Richard L Adams	-	-	-	-	-	-	-	300,000.00	300,000 00
Total Legal	**$310,559.73**	**$176,676.93**	**$193,941.06**	**$94,486.40**	**$145,487.72**	**$175,386.62**	**$1,096,538.46**	**$3,800,000.00**	**$4,896,538.46**
Consulting									
Depreciation Study (Alliance Consulting)	8,717 50	-	7,935 00	3,079 13	-	-	19,731 63	180,000.00	199,731 63
ROE Consultant (ScottMadden)	-	-	-	-	-	-	-	65,000 00	65,000 00
Pension/OPEB (Aon Consulting/Hewitt)	11,573.00	-	-	-	-	-	11,573 00	320,000 00	331,573.00
Insurance Reserve (Lewis & Ellis)	-	-	-	-	-	-	-	20,000.00	20,000 00
Income Taxes (PWC)	12,602 00	2,590 00	-	-	-	-	15,192.00	20,000.00	35,192.00
Keith Pruett (Accounting, Cost of Service)	-	-	-	-	-	-	-	40,000 00	40,000 00
Steve Ragland (Accounting, Affiliate)	-	-	-	-	-	-	-	15,000.00	15,000 00
James Shrewsberry (Rate Design)	-	-	-	-	-	-	-	15,000 00	15,000 00
Theresa Gage (Policy)	-	-	-	-		-	-	30,000.00	30,000 00
Cash Working Capital Consultant (Newman)	760 00	-	-	-	-	-	760 00	-	760 00
Rate Case Expense Consultant (Baker Botts)	-	-	-	-	-	-	-	50,000 00	50,000.00
Outsourcing Consultant (Woodview Advisors)	-	-	-	-	-	-	-	80,000 00	80,000 00
Outsourcing Support (KPMG)	-	-	-	-	-	-	-	380,000 00	380,000.00
Capital Structure Consultant (Lapson)	-	9,800 00	-	-	-	-	9,800.00	125,000 00	134,800.00
Rate Base (Principle Services LLC)	-	-	-	-	-	-	-	10,000 00	10,000 00
Rate Base (Burns & McDonnell)	-	-	-	-	-	-	-	550,000 00	550,000 00
Total Consulting	**$33,652.50**	**$12,390.00**	**$7,935.00**	**$3,079.13**	**$0.00**	**$0.00**	**$57,056.63**	**$1,900,000.00**	**$1,957,056.63**
Other Company Expenses									
Employee Expenses	-	2,352 09	2,389 40	961.63	-	53 57	5,756.69	20,000 00	25,756 69
Printing of Rate Filing Package	-	-	7,949 88	20,814 74	-	-	28,764.62	100,000 00	128,764.62
Newspaper Public Notice	-	367 77	-	-	32,766.73		33,134 50	75,000 00	108,134 50
Transcripts of Hearings	-	281 45	260 00	265 00	-	-	806 45	45,000 00	45,806.45
Office Supplies & Miscellaneous Costs	483 04	405 67	3,415 02	2,622 18	228 40	977 67	8,131 98	60,000 00	68,131 98
Credit - Rider RCE Regulatory Liability	(254,178.24)	-	-	-	-	-	(254,178 24)	-	(254,178 24)
Total Other Company Expenses	**($253,695.20)**	**$3,406.98**	**$14,014.30**	**$24,663.55**	**$32,995.13**	**$1,031.24**	**($177,584.00)**	**$300,000.00**	**$122,416 00**
Intervenor Expenses									
Steering Committee of Cities	175,396 08	24,751 94	20,935 97	22,862 96	-	18,849 60	262,796 55	500,000 00	762,796.55
Alliance of Oncor Cities (AOC)	66,081 35	39,330 76	31,359 79	22,636 10	-	20,254 00	179,662 00	200,000 00	379,662.00
City of Mission	-	78,228.42	36,429 87	-	-	-	114,658 29	-	114,658.29
Total Intervenor Expenses	**$241,477 43**	**$142,311.12**	**$88,725.63**	**$45,499.06**	**$0.00**	**$39,103.60**	**$557,116.84**	**$700,000.00**	**$1,257,116.84**
Total Rate Case Expenses to Date	**$331,994 46**	**$334,785.03**	**$304,615.99**	**$167,728.14**	**$178,482.85**	**$215,521.46**	**$1,533,127.93**	**$6,700,000.00**	**$8,233,127.93**

2022 RATE CASE
ONCOR ELECTRIC DELIVERY COMPANY LLC
WORKPAPERS FOR
THE DIRECT TESTIMONY OF
ROBERT A. SCHMIDT

In accordance with RFP General Instruction No. 12(c), below is a list of the files that are being provided electronically:

Testimony Workpapers/Schmidt

Schmidt Testimony Workpapers.pdf

Rate Case Estimate - 2021 Test Year

	Paid Through	Current Amount	Hours	Average/Hour	Rate Case Estimate
Law Firms					
Vinson & Elkins	Jan 2022	$ 1,115,945	1,592.8	$ 701	$ 1,650,000
Hunton Andrews Kurth	Jan 2022	$ 1,270,880	1,860.7	$ 683	$ 1,850,000
Richard L. Adams Law PLLC	Feb 2022	$ 190,965	251.1	$ 761	$ 300,000
Subtotal Legal		$ 2,577,790			$ 3,800,000
Consultants					
Alliance Consulting (D. Watson)	Feb 2022	$ 147,365	664.3	$ 222	$ 180,000
Aon Consulting (A. Taper)	Feb 2022	$ 266,194	328.7	$ 810	$ 320,000
Baker Botts (A. Stover)	Feb 2022	$ 28,050	41.0	$ 684	$ 50,000
Burns & McDonnell (J. Nichols)	May 2021	$ 424,895	2,010.8	$ 211	$ 550,000
Theresa Gage	Feb 2022	$ 450	3.0	$ 150	$ 30,000
Lapson Advisory (E. Lapson)	Feb 2022	$ 105,913	211.8	$ 500	$ 125,000
Lewis & Ellis (G. Wilson)	Feb 2022	$ 8,085	16.5	$ 490	$ 20,000
Principle Services (T. Vaughn)	November 2020	$ 4,841	12.9	$ 375	$ 10,000
Keith Pruett	Feb 2022	$ 27,375	119.3	$ 230	$ 40,000
PWC (S. Maltalbano)	February 2021	$ 4,500	6.0	$ 750	$ 20,000
Steve Ragland	Feb 2022	$ 8,748	58.0	$ 151	$ 15,000
ScottMadden, Inc. (D. D'Ascendis)	Jan 2022	$ 32,855	113.8	$ 289	$ 65,000
James Shrewsberry	Feb 2022	$ 9,800	116.0	$ 84	$ 15,000
Woodview Advisors (M. Smith)	Feb 2022	$ 54,810	101.5	$ 540	$ 80,000
KPMG (Support M. Smith)	Feb 2022	$ 330,287	1,082.1	$ 305	$ 380,000
Subtotal Consulting		$ 1,454,168			$ 1,900,000
Other Expenses					
Employee Expenses		$ -			$ 20,000
Printing of Rate Filing Package	February 2021	$ 2,113			$ 100,000
Newspaper Notice		$ -			$ 75,000
Hearings Transcripts		$ -			$ 45,000
Miscellaneous		$ -			$ 60,000
Subtotal Other		$ 2,113			$ 300,000
Intervenor Expenses					
Cities (Steering Committee)		$ -			$ 500,000
Alliance of Oncor Cities (AOC)		$ -			$ 200,000
Subtotal Intervenors		$ -			$ 700,000
Total Dec 2021 TY Rate Case Expenses		$ 4,034,071			$ 6,700,000

Oncor December 2021 Test Year Rate Case Expenses
Listing of Legal and Consulting Hourly Rates

Firm Name	Name	Title	Rate	Rate Range
Vinson & Elkins	JoAnn Biggs	Partner	$775	$735 - $775
- Legal	Jaren Taylor	Partner	$775	$750 - $775
	Winston Skinner	Counsel	$675	$650 - $675
	Erik Jacobson	Associate	$575	$550 - $575
	Jared Jones	Associate	$490	$405 - $490
Hunton Andrews Kurth	Tab Urbantke	Partner	$770	
- Legal	Myles Reynolds	Partner	$770	
	Alan Marcuis	Partner	$717	$695 - $717
	James Ritter	Associate	$638	$568 - $638
	Lauren Freeland	Associate	$650	$612 - $650
	Lauren Freeland	Counsel	$686	
	Alicia Kliner	Associate	$506	$440 - $506
	K. Thomas	Associate	$475	
	Christina Reeves	Paralegal	$360	$345 - $360
Richard L Adams Law PLLC	Richard Adams	Partner/Principal	$800	$700 - $800
Alliance Consulting	Dane Watson	Partner	$270	
- Depreciation Study	Karen Ponder	Senior Consultant	$195	
	Rhonda Watts	Senior Consultant	$195	
	Rebecca Richards	Senior Consultant	$195	
	Alan Ponder	Consultant/Admin	$70	
Aon Consulting	Alan Taper	Lead Actuarial Consultant	$1,016	$976 - $1,016
- Pension/OPEB	Allison Logan	Senior Actuarial Consultant	$920	$884 - $920
	Brian Walker	Senior Actuarial Consultant	$920	$884 - $920
	Gina Evans	Actuarial Consultant	$668	$644 - $668
	Richard Maaznek	Actuarial Consultant	$668	$644 - $668
	Justin Adler	Senior Actuarial Analyst	$512	$440 - $512
	Courtney Morris	Senior Actuarial Analyst	$512	$440 - $512
	Anna Breck	Actuarial Analyst	$368	$352 - $368
	Mika Teachout	Administrative Support	$296	
Baker Botts	Andrea Stover	Partner	$675	
- Rate Case Expenses	Leah Burcat	Associate	$550	
	Gabbi Feldman	Associate	$450	
	Landon Lill	Associate	$550	
	Brian Lynch	Paralegal	$300	
Burns & McDonnell	Joseph Nichols	Consultant	$263	$263 - $355
- Sharyland Assets	Omar Urquidez	Consultant	$263	$263 - $355
	Ravikanth Varanasi	Consultant	$277	$277 - $380
	Doug Houseman	Consultant	$289	$289 - $395
	Francesca Winter	Consultant	$263	
	Jeffrey Kopp	Consultant	$380	
	Michael Cote	Consultant	$237	
	Preety Mathora	Consultant	$237	
	Aishwarya Chakravarthy	Consultant	$214	
	Jeffrey Chapman	Consultant	$198	
	Jonathan Branscomb	Consultant	$198	
	Mohammed Moderresi	Consultant	$198	
	Chad Courter	Consultant	$173	
	Jacob Wells	Consultant	$146	
	Stewart Krinickas	Consultant	$146	
	Hy Luu	Consultant	$146	
	Kiara Ross	Consultant	$146	

Oncor December 2021 Test Year Rate Case Expenses
Listing of Legal and Consulting Hourly Rates

Firm Name	Name	Title	Rate	Rate Range
Theresa Gage - Policy/Review	Theresa Gage	Consultant	$150	
Lapson Advisory - Capital Structure	Ellen Lapson John Perkins	Principal Associate	$600 $375	
Lewis & Ellis, Inc. - Insurance Reserve	Gregory Wilson	VP & Principal	$490	
Principle Services - Rate Base/Acquisitions	Troy Vaughn	Consultant	$375	
Keith Pruett - Accounting/Cost of Service	Keith Pruett	Consultant	$150	$150 - $250 1st 20 hrs $150 > 20 hrs $250
PWC - Federal Income Tax	Sal Montalbano	Partner/Principal Managing Director Director/Senior Manager Manager Senior Associate Associate Administrative Assistance	$750 $650 $450 $350 $250 $200 $100	
Steve Ragland - Accounting/Affiliate	Steve Ragland	Consultant	$150	$150 - $250 1st 20 hrs $150 > 20 hrs $250
ScottMadden, Inc. - ROE	Logan Toms Dylan D'Ascendis Matthew Howard Sara Derstine	Partner Director Manager Senior Associate Associate Senior Analyst Analyst/Research Analyst Administrative Assistant	$470 $365 $340 $300 $255 $170 $145 $65	
James Shrewsberry - Rate Design	James Shrewsberry	Consultant	$125	$75-$200 1st 20 hrs $125 > 20 hrs $200
Woodview Advisors - Outsourcing	Matthew Smith	Partner	$540	
KPMG - Outsourcing	Tom Peterson Thomas Heck Kyle McNamara Mahendra Goyal David Perera Michele Loux Kushal Singha	Managing Director Partner Director Director Manager Manager Senior Associate	$540 $540 $485 $485 $430 $430 $350	

INDEX TO THE DIRECT TESTIMONY
OF ANDREA M. STOVER, WITNESS FOR
ONCOR ELECTRIC DELIVERY COMPANY LLC

DIRECT TESTIMONY OF ANDREA M. STOVER

I. INTRODUCTION

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

A. My name is Andrea M. Stover. I am a Partner at the law firm Baker Botts L.L.P. ("Baker Botts"). My business address is 98 San Jacinto, Suite 1500, Austin, Texas 78701.

II. PURPOSE OF DIRECT TESTIMONY

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of Oncor Electric Delivery Company LLC ("Oncor" or the "Company").

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my direct testimony is to address the standards by which Oncor is entitled to recover its reasonable and necessary expenses associated with participating in this and prior rate proceedings, and to address the importance of Oncor having skilled and experienced professionals to support its rate applications. As discussed in more detail below, the analysis in my testimony is based upon the standards set forth in Public Utility Regulatory Act ("PURA") § 36.061(b)(2) and the rate-case expense rule, 16 Tex. Admin. Code ("TAC") § 25.245 (the "RCE Rule"), but I also consider and discuss other relevant legal authorities. Additionally, my testimony will apply those standards to the facts and circumstances of Oncor's rate case and will support Oncor's recovery of reasonable legal and consulting fees and expenses that have been or will be incurred during the rate case and other prior cases.

My direct testimony is organized consistent with the topics set forth above and, along with my exhibit, was prepared by me or under my direction, supervision, or control and is, to the best of my knowledge and belief, true and correct.

III. QUALIFICATIONS

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND, HONORS AND RELEVANT PROFESSIONAL ASSOCIATIONS.

A. I have a Bachelor of Arts with a major in Government from the University of Texas, and a Juris Doctor, Magna Cum Laude, from American University, Washington College of Law. I am a member of the Public Utility Law Section of the State Bar, and I am a Past Chair for the Executive Council of the Administrative and Public Law Section of the State Bar. I have spoken about power and utility issues at many industry conferences and continuing legal education seminars in my career. My resume is attached as Exhibit AMS-1 to my testimony.

Q. PLEASE DESCRIBE YOUR RELEVANT PROFESSIONAL EXPERIENCE.

A. I have practiced before federal and state agencies, as well as in state and federal courts for almost 18 years. My primary area of focus is energy regulatory law, particularly in Texas at the Public Utility Commission of Texas ("Commission"). My current and past clients include vertically integrated utilities, transmission and distribution utilities, power generators, and retail electric providers. I have represented electric utilities in base-rate proceedings, change of control applications, applications for certificates of convenience and necessity cases, fuel rate proceedings and other matters before the Commission since 2006. I have acted as legal counsel for utility clients in dozens of matters, including in the following dockets: 34442, 35763, 37771, 38147, 38283, 38524, 38877, 38974, 39467, 39572, 40125, 40216, 40550, 40824, 41222, 41334, 41921, 42004,42388, 42729, 43695, 44547, 44726, 45158, 45524, 46025, 46042, 46734, 48629, 48929, 49421, 51568, 51625, 51665, 52210 and 53034.

Additionally, I provided rebuttal testimony on behalf of Southwestern Electric Power Company on the issue of rate-case expenses in Docket No. 47141.

Through my many years of professional experience, I have become familiar with what is involved in trying contested cases—of varying complexity—at the Commission, including several base rate proceedings. Through my representation of clients in rate proceedings and other cases, I have gained knowledge and familiarity with the hourly rates charged by outside consultants and legal counsel and the necessary efforts that must be expended by legal counsel to effectively represent a client in rate proceedings. Additionally, as a partner at Baker Botts and my previous firm, I have reviewed invoices related to legal work performed for the firm's electric utility and other clients.

IV. STANDARDS FOR RECOVERY

Q. DOES PURA ALLOW ONCOR TO RECOVER ITS RATE-CASE EXPENSES?

A. Yes. The setting of rates for electric utilities is governed by PURA Chapter 36. Specifically, PURA § 36.061(b) permits the recovery of reasonable costs and expenses associated with participating in rate proceedings under Chapter 36.

Q. WHAT STANDARDS ARE USED TO DETERMINE THE REASONABLENESS OF COSTS OF PARTICIPATING IN A PROCEEDING?

A. PURA § 36.061(b) states that "[t]he regulatory authority may allow as a cost or expense . . . reasonable costs of participating in a proceeding under this title not to exceed the amount approved by the regulatory authority." The Third Court of Appeals, in *City of El Paso v. Pub. Util. Comm'n of Tex.*, 916 S.W.2d 515, 522 (Tex. App.—Austin 1995, writ dism'd), affirmed that a "utility's requested rate-case expenses will be reimbursed if the Commission finds them to be reasonable." The *City of El Paso* court went on to describe certain factors that the Commission stated that it considers when determining the reasonableness of rate-case expenses, noting, however,