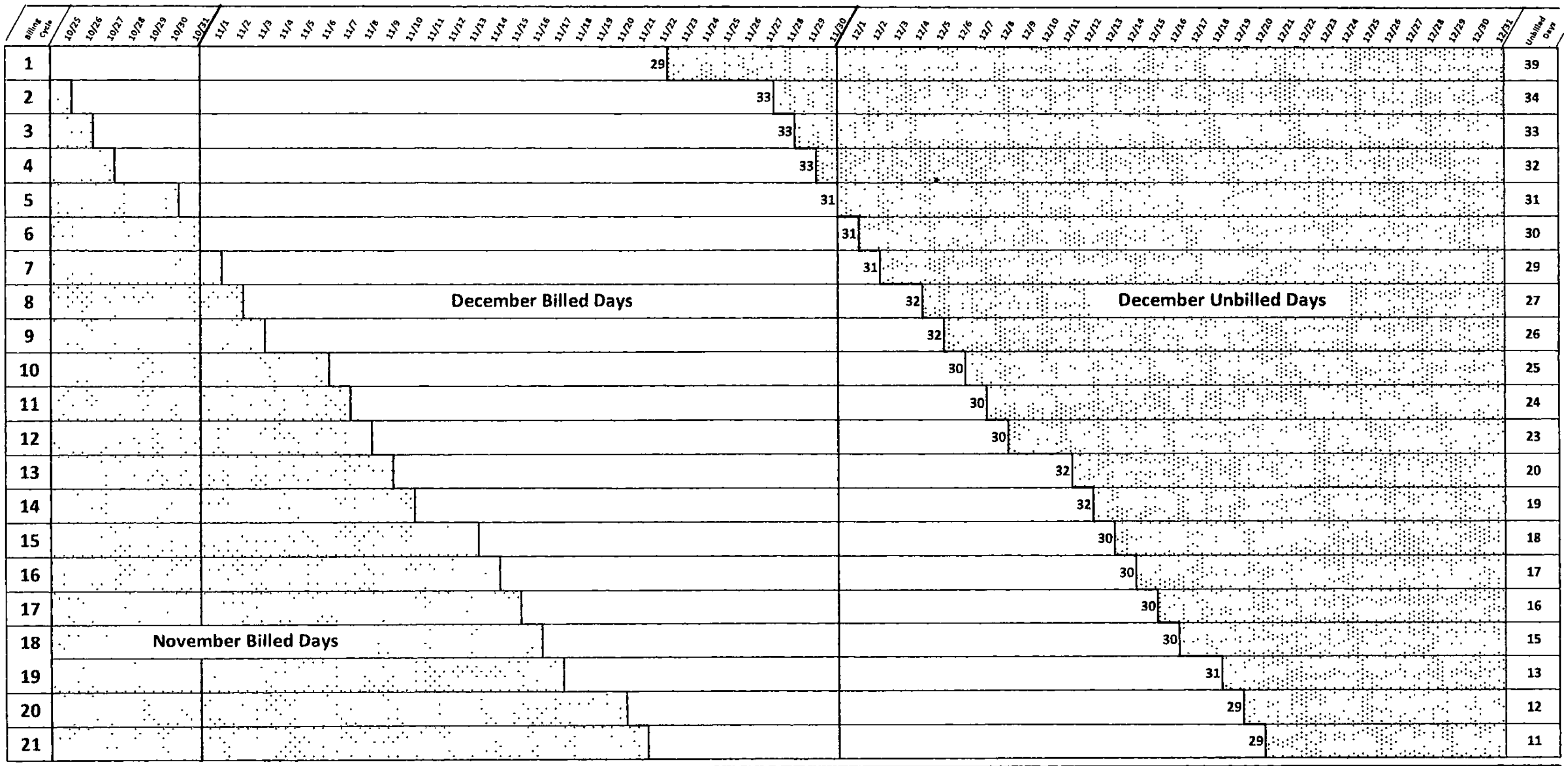
Oncor Electric Delivery Company LLC
December 2022 Billing Cycle Illustration



12/2022 Total Billed Days	648	12/2022 Total Unbilled Days	494
Average Billed Days / Cycle	30.9	Average Unbilled Days / Cycle	23.5

2022 RATE CASE
ONCOR ELECTRIC DELIVERY COMPANY LLC
ORIGINAL COST OF TRANSMISSION AND DISTRIBUTION PLANT
AT DECEMBER 31, 2021

Line No	Account Number (a)	Description (b)	Adjusted T&D Electric (c)	TRAN (d)	NTU TRAN (e)	DC Tie (f)	Consol TRAN (g)=(d)+(e)+(f)	DIST (h)	NTU DIST (i)	Consol DIST (j)=(h)+(i)	MET (k)	TDCS (l)	Total (m)=(g)+(j)+(k)+(l)	Functionalization Method (n)
1		Transmission Plant-Gross												
2	A349	Land Owned in Fee	$ 115,906,329	$ 93,368,707	$ 22,537,622	$ -	$ 115,906,329	$ -	$ -	$ -	$ -	$ -	$ 115,906,329	Direct Assigned - Based on FERC Account
3	A350	Land and Land Rights	615,926,404	521,566,383	94,360,022	-	615,926,404	-	-	-	-	-	615,926,404	Direct Assigned - Based on FERC Account
4	A352	Structures and Improvements	420,045,891	325,121,521	93,237,801	1,686,569	420,045,891	-	-	-	-	-	420,045,891	Direct Assigned - Based on FERC Account
5	A353	Station Equipment	3,929,015,687	3,167,599,763	296,846,116	30,852,549	3 495,298,428	381,860,651	51,856,608	433,717,258	-	-	3,929,015,687	(1)
6	A354	Towers and Fixtures	1,929,652,755	1,433,247,199	496,405,556	-	1,929,652,755	-	-	-	-	-	1,929,652,755	Direct Assigned - Based on FERC Account
7	A355	Poles and Fixtures	2,870,770,311	2,646,547,291	224,223,020	-	2,870,770,311	-	-	-	-	-	2,870,770,311	Direct Assigned - Based on FERC Account
8	A356	Overhead Conductors and Devices	3,044,581,320	2,597,173,723	447,407,596	-	3,044,581,320	-	-	-	-	-	3,044,581,320	Direct Assigned - Based on FERC Account
9	A357	Underground Conduit	60,197,135	60,197,135	-	-	60,197,135	-	-	-	-	-	60,197,135	Direct Assigned - Based on FERC Account
10	A358	Underground Conductors and Devices	84,097,343	84,097,343	-	-	84,097,343	-	-	-	-	-	84,097,343	Direct Assigned - Based on FERC Account
11	A359	Roads and Trails	-	-	-	-	-	-	-	-	-	-	-	Not Applicable
12														
13		Transmission Plant Total	$ 13,070,193,174	$ 10,928,919,064	$ 1,675,017,734	$ 32,539,118	$ 12,636,475,916	$ 381,860,651	$ 51,856,608	$ 433,717,258	$ -	$ -	$ 13,070,193,174	
14														
15		Distribution Plant-Gross												
16	A360	Land and Land Rights	$ 24,366,923	$ 1,320,895	$ -	$ -	$ 1,320,895	$ 23,046,028	$ -	$ 23,046,028	$ -	$ -	$ 24,366,923	(1)
17	A361	Structures and Improvements	227,950,838	53,159,679	16,042,221	-	69,201,900	137,062,053	21,686,884	158,748,938	-	-	227,950,838	(1)
18	A362	Station Equipment	2,436,284,041	571,075,226	39,195,174	-	610,270,400	1,760,200,030	65,813,611	1,826,013,641	-	-	2,436,284,041	(1)
19	A363	Storage Battery Equipment	-	-	-	-	-	-	-	-	-	-	-	Not Applicable
20	A364	Poles, Towers and Fixtures	2,679,007,190	-	-	-	-	2,678,358,261	648,929	2,679,007,190	-	-	2,679,007,190	Direct Assigned - Based on FERC Account
21	A365	Overhead Conductors and Devices	1,676,515,252	-	-	-	-	1,675,410,858	1,104,394	1,676,515,252	-	-	1,676,515,252	Direct Assigned - Based on FERC Account
22	A366	Underground Conduits	1,082,662,296	-	-	-	-	1,082,118,478	543,818	1,082,662,296	-	-	1,082,662,296	Direct Assigned - Based on FERC Account
23	A367	Underground Conductors and Devices	2,555,767,640	-	-	-	-	2,553,927,528	1,840,112	2,555,767,640	-	-	2,555,767,640	Direct Assigned - Based on FERC Account
24	A368	Line Transformers	2,493,082,807	-	-	-	-	2,493,077,762	5,044	2,493,082,807	-	-	2,493,082,807	Direct Assigned - Based on FERC Account
25	A369	Services	1,652,238,990	-	-	-	-	1,652,238,990	-	1,652,238,990	-	-	1,652,238,990	Direct Assigned - Based on FERC Account
26	A370	Meters	574,147,483	-	-	-	-	-	-	-	574,147,483	-	574,147,483	Direct Assigned - Based on FERC Account
27	A371	Installations on Customers' Premises	54,631,097	-	-	-	-	54,631,097	-	54,631,097	-	-	54,631,097	Direct Assigned - Based on FERC Account
28	A372	Leased Property on Customers' Premises	-	-	-	-	-	-	-	-	-	-	-	Not Applicable
29	A373	Street Lighting and Signal Systems	437,411,078	-	-	-	-	437,403,826	7,252	437,411,078	-	-	437,411,078	Direct Assigned - Based on FERC Account
30	A374	Land Owned in Fee	96,116,029	24,591,239	49,119	-	24,640,358	71,344,821	130,850	71,475,671	-	-	96,116,029	(1)
31														
32		Distribution Plant Total	$ 15,990,181,663	$ 650,147,039	$ 55,286,514	$ -	$ 705,433,553	$ 14,618,819,733	$ 91,780,895	$ 14,710,600,627	$ 574,147,483	$ -	$ 15,990,181,663	
33														
34		(1) Substation equipment is directly assigned based on voltage Common assets are allocated based on directly assigned equipment												

Oncor Electric Delivery Company LLC
Summary of Net Regulatory Assets and Liabilities
At December 31, 2021 Test-Year-End

		SEC Form 10-K (in millions)	Exclude TCRF reclass *	Adjusted	Non-Tax
		(a)	(b)	(c)	(d)
1	Regulatory Assets Non-Tax	$ 1,531	$ 58	$ 1,589	$ 1,589
2	Regulatory Assets Tax	$ 16		$ 16	
3	Regulatory Liabilities Non-Tax	$ (1,434)	$ (58)	$ (1,492)	$ (1,492)
4	Regulatory Liabilities Tax	$ (1,442)		$ (1,442)	
5	Net regulatory assets (liabilities)	$ (1,329)	$ -	$ (1,329)	$ 97

	Description	Unadjusted Test Year Amount	Tax/Non-Tax	Rate Base Treatment	Adjustments
6	(e)	(f)	(g)	(h)	(i)
7	Unamortized Losses - Reacquired Debt	$ 19,458,185	Non-Tax	No	(reclassified to Weighted Average Cost of Long-Term Debt Schedule II-C-2 4)
8	Rocky Mound Series Compensator	$ 1,518,898	Non-Tax	Yes	
9	HB 2483 Mobile Generators & related costs	$ 26,088	Non-Tax	Yes	
10	Energy Efficiency Perf Bonus	$ 30,796,489	Non Tax	No	
11	Reg Asset - Defaulted REPs	$ 8,889,387	Non-Tax	Yes	
12	Deferred COVID19-Incremental Expense	$ 34,659,803	Non-Tax	Yes	
13	Deferred Pension Costs (reviewed)	$ 172,977,830	Non-Tax	Yes	
14	Deferred Pension Costs (unreviewed)	$ (17,440,156)	Non-Tax	Yes	
15	Deferred OPEB Costs (reviewed)	$ 18,815,910	Non-Tax	Yes	
16	Employee Retirement Costs (unfunded)	$ 328,914,729	Non-Tax	No	
17	CWIP Distribution Non-Service Cost for Pension/OPEBs	$ 1,555,473	Non-Tax	No	(reclassified to Construction Work in Progress Schedule II-B-4 Total Company)
18	CWIP Transmission Non-Service Cost for Pension/OPEBs	$ 413,480	Non-Tax	No	(reclassified to Construction Work in Progress Schedule II-B-4 Total Company)
19	Net Plant Distribution Non-Service Cost for Pension/OPEBs	$ 90,529,283	Non-Tax	Yes	(reclassified to Plant II-B-1 and Accumulated Depreciation Schedule II-B-5 Total Company)
20	Net Plant Transmission Non-Service Cost for Pension/OPEBs	$ 24,222,553	Non-Tax	Yes	(reclassified to Plant II-B-1 and Accumulated Depreciation Schedule II-B-5 Total Company)
21	Advanced Meter Employee Severance Costs (reviewed)	$ 59,201	Non Tax	Yes	
22	Advanced Meter Case Costs (reviewed)	$ 80,080	Non-Tax	Yes	
23	Advanced Meter Customer Education Costs (reviewed)	$ 524,869	Non-Tax	Yes	
24	Deferred Advanced Metering System Costs (reviewed under-recovery)	$ 127,299,791	Non-Tax	Yes	
25	Wholesale Distribution Substation Service	$ 75,267,069	Non-Tax	Yes	
26	Sharyland Residential Interim Rate	$ 627,363	Non-Tax	Yes	
27	Study Costs/Transition to Comp (NTU)	$ 2,602,847	Non-Tax	Yes	
28	PowerLineSafetyAct PURA 36066	$ 7,547,565	Non-Tax	Yes	
29	Self-Insurance (reviewed)	$ 223,287,200	Non-Tax	Yes	
30	Self-Insurance (unreviewed)	$ 365,258,457	Non-Tax	Yes	
31	Workers Compensation	$ 8,098,712	Non-Tax	No	
32	Transmission Cost Recovery under-/(over-)recovery *	$ 58,314,504	Non-Tax	No	
33	Rate Case Expenses (Non-standard Metering Opt-out)	$ 23,799 09	Non-Tax	No	
34	Rate Case Expenses - 2016 Test Year, Docket No 46957 (Post-Cutoff)	$ 586,173	Non-Tax	Yes	
35	Rate Case Expenses - TCJA Tax Case, Docket No 48325	$ 334,785	Non-Tax	Yes	
36	Rate Case Expenses - DCRF Case, Docket No 48231	$ 304,616	Non-Tax	Yes	
37	Rate Case Expenses - DCRF Case, Docket No 49427	$ 167,728	Non-Tax	Yes	
38	Rate Case Expenses - AMS Reconciliation, Docket No 49721	$ 178,483	Non-Tax	Yes	
39	Rate Case Expenses - DCRF Case, Docket No. 51996	$ 215,521	Non-Tax	Yes	
40	Rate Case Expenses - December 2021 Test Year Rate Case	$ 3,421,290	Non-Tax	Yes	
41	Non-Tax Regulatory Assets	$ 1,589,538,005	Non-Tax Sch II-B-12 Total Company Line No 37		
42	Recoverable Deferred Income Taxes-Net	$ 15,965,291	Tax	Yes	
43	Regulatory Assets	$ 1,605,503,296			
44	Estimated net removal costs	$ (1,348,181,167)	Non-Tax	Yes	(reclassified to Accumulated Depreciation Schedule II-B-5)
45	Energy Efficiency program under-/(over-)recovery	$ 4,711,219	Non-Tax	No	
46	Over-amortization of intangible investment	$ (13,536,943)	Non-Tax	Yes	
47	Deferred Energy Efficiency program	$ (3,284,128)	Non-Tax	No	
48	TCRF Unbilled Revenue Deferral *	$ (65,327,867)	Non-Tax	No	
49	AMS Unbilled Revenue Deferral	$ (1,233,869)	Non-Tax	No	
50	Capital structure refund Dkt 48522 (over-refund)	$ 81,644	Non-Tax	Yes	
51	FIT rate refund Dkt 48325 (over-refund)	$ 2,368,303	Non-Tax	Yes	
52	Interest-rate savings Dkt 47675 & Dkt 53320	$ (1,946,863)	Non-Tax	No	
53	Docket No. 46957 Rider RCE (over-collection)	$ (254,178)	Non-Tax	Yes	
54	Deferred OPEB Costs (unreviewed)	$ (39,289,144)	Non-Tax	Yes	
55	Unamortized Gains - Reacquired Debt	$ (26,090,760)	Non-Tax	No	(reclassified to Weighted Average Cost of Long-Term Debt Schedule II-C-2 4)
56	Non-Tax Regulatory Liabilities	$ (1,491,983,752)	Non-Tax Sch II-B-12 Total Company Line No 51		
57	Excess Deferred Taxes	$ (1,442,522,098)	Tax	Yes	
58	Regulatory Liabilities	$ (2,934,505,850)			
59	Net Regulatory Liability Non-Tax and Tax	$ (1,329,002,554)	Sch II-B-12 Total Company Line No 80		
60	Non-Tax Reg Assets/(Liabilities) Sch II-B-12 Total Company Line No 53	$ 97,554,253			
61	Tax Reg Assets/(Liabilities)	$ (1,426,556,807)			
62	Sch II-B-12 Total Company Line No 80	$ (1,329,002,554)			

ONCOR

ONCOR PRINCIPLES, POLICIES AND PROCEDURES – ACCOUNTING

Title:	**50-02 Allowance for Funds Used During Construction (AFUDC)**
Responsible Officer:	**Controller**
Contact:	**Mindy Marshall (214-486-3173)**
Last Reviewed/Revised Date:	**June 21, 2021**

Scope / Application

This accounting policy and procedure ("AP&P") applies to all Oncor business organizations constructing capital assets.

Purpose

The purpose of this policy is to establish a uniform policy and procedure for the computation, accrual, and allocation of Allowance for Funds Used During Construction (AFUDC).

Policy

The Federal Energy Regulatory Commission (FERC) Uniform System of Accounts lists AFUDC as one of the components of construction cost. AFUDC is a cost accounting procedure whereby amounts based upon interest charges on borrowed funds and a return on equity capital used to finance construction are charged to electric plant. The accrual of AFUDC is in accordance with generally accepted accounting principles for the industry, but does not represent current cash income.

The regulated business organizations and assets of Oncor that fall under SFAS 71 are capitalizing AFUDC as required by FERC, compounded semiannually, on expenditures for ongoing construction work in progress (CWIP) not otherwise allowed in rate base by regulatory authorities. The AFUDC rate is determined on the basis of, but is less than, the cost of capital used to finance the construction program.

Procedure

Computation of AFUDC Rate

AFUDC rates are based on the capital structure of the Company as of the end of the prior fiscal year. The AFUDC rate is calculated using estimates of the short-term debt balances and related cost applicable to CWIP and the average balances of CWIP. The balances for long-term debt, preferred stock, preferred securities, and common equity are the actual book balances as of the end of the prior fiscal year. The cost rates for long-term debt, preferred stock, and preferred securities are the weighted average cost of such capital. The cost rate for common equity is the rate that was granted in the most recent rate proceeding. The AFUDC rate is monitored and calculated monthly until year end using 13 month averages of short-term debt applicable to CWIP and CWIP balances (both calculated using actual balances as they occur plus outstanding estimates); and, the weighted average cost of equity and long term debt. After determining the maximum AFUDC accrual rate, Property Accounting calculates the percentage allocation between borrowed funds (Debt) and other funds (Equity). Monthly, the Oncor Assistant Controller

reviews the maximum allowable AFUDC rate as calculated by Property Accounting, and selects a rate less than or equal to that maximum.
If the actual AFUDC rate projected for the end of the year is higher than the AFUDC rate applied during the year by 25 basis points or more, the rate is changed on a retroactive basis to the beginning of the year to reflect the new rate per the requirements of FERC Order Number 561. This retroactive adjustment usually occurs near the end of the year.

AFUDC Rate Formula

The formula and elements for the computation of the allowance for funds used during construction as prescribed by FERC are:

$Ai = s\,(S/W) + d\,(D/D+P+C)\,(1-S/W)$

$Ae = [1-S/W]\,[p\,(P/D+P+C) + c\,(C/D + P + C)]$

This rate is reduced programmatically within the Financial Information Management (FIM) system to reflect a semi-annual compounding using the following formula:

$Ais = (1 + Ai/2)^{1/6} - 1$
$Aes = (1 + Ae/2)^{1/6} - 1$

Where:
Ai=Gross allowance for borrowed funds used during construction rate.

Ae=Allowance for other funds used during construction rate.

Ais and Aes = Semi-annual compounded rate equivalent to Ai and Ae.

Elements:
S=Average short-term debt.

s=Short-term debt interest rate.

D=Long-term debt.

d=Long-term debt interest rate.

P=Preferred stock and securities.

p=Preferred stocks and securities cost rate.

C=Common equity.

c=Common equity cost rate.

W=Average balance in CWIP.

Application of AFUDC

AFUDC is accrued using the process as shown below. The current month AFUDC accrual is calculated at month end using the prior month CWIP balance of each eligible project, plus or minus any adjustments, multiplied times the monthly AFUDC rate.

EXAMPLE

A project is estimated to install facilities on a customer's premises. Construction is to begin 1-1-06 and be completed 5-1-06. The customer is to pay $100,000 in advance, representing Contributions In Aid of Construction (CIAC). Construction costs are as follows:

New Construction (excluding CIAC & AFUDC) = $235,000

The cost subject to AFUDC would be $135,000 ($235,000-$100,000). Since this is a FIM capital project to construct facilities and the construction period is greater than thirty days, this project will receive AFUDC. The estimated AFUDC is as follows:

	JAN	FEB	MAR	APR	MAY	TOTAL
Beginning Balance	-	($25,000)	$15,000	$55,131	$95,613	-
Customer Payment	($100,000)	-	-	-	-	($100,000)
Construction Expenditures	75,000	40,000	40,000	40,000	40,000	235,000
Estimated AFUDC	-	-	131	482	837	1,450
Ending Balance	(25,000)	15,000	55,131	95,613	136,450	136,450
Previous Month's						
Balance Times	-	-	15,000	55,131	95,613	
AFUDC Monthly Rate	0.00875	0.00875	0.00875	0.00875	0.00875	
Estimated AFUDC			$ 131	$ 482	$ 837	

Property Accounting calculates the monthly accrual of AFUDC estimate using the appropriate accrual rate applied against eligible CWIP project balances based on the following criteria:

- Must be a valid capital project in FIM
- Requires at least 30 days to complete
- Cost at least $1

An eligible project will receive AFUDC beginning the month after charges to the job are first recorded and will continue to receive AFUDC until the project is put in service. If it is determined that a project currently receiving AFUDC is delayed for a period of one year or more, written notification should be sent to Property Accounting requesting temporary discontinuance of AFUDC. This notification should include an explanation for the delay, an estimate when construction will continue, and a signature from the level of management which authorized the project or a superior level.

Note: Property Accounting will review each such notification with the Assistant Controller. The projects that qualify will be excluded from the AFUDC and allocation bases. Generally, no adjustment will be made for periods prior to the current month AFUDC accrual. The project will be excluded from the AFUDC process until construction expenditures resume on a continuous basis. In the month following the month that construction expenditures resume, the AFUDC accrual on this project will resume.

ACCOUNTING STRUCTURE:

Accrual and Allocation of AFUDC is recorded by the following entries:

Debit

Each eligible CWIP project

Credit

- Expense account 4321000-AFUDC Debt
- Revenue account 4191000-AFUDC Equity

Revision History

June 11, 2010	Adoption of Oncor policy
November 7, 2011	Updated policy to delete section on, and other references to Capitalized Interest.
August 17, 2015	Deleted reference to accrual period is from the 16th day of the prior month to the 15th day of the current period.
August 15, 2017	Review of Oncor policy on August 15, 2017 – No changes.
August 30, 2019	Updated policy for title change and short term debt ceiling
June 21, 2021	Updated title from Director of Accounting to Assistant Controller

ONCOR PRINCIPLES, POLICIES AND PROCEDURES - ACCOUNTING

Title:	**50-01 Capitalization of Indirect Construction Overhead**
Responsible Officer:	**Controller**
Contact:	**Mindy Marshall (214-486-3173)**
Last Reviewed/Revised Date:	**March 9, 2021**

Purpose

To establish an accounting policy and procedure ("AP&P") for the capitalization of indirect construction overhead costs.

Policy

The Federal Energy Regulatory Commission (FERC) and National Association of Regulatory Utility Commissioners (NARUC) Uniform System of Accounts provides for the capitalization of indirect construction overhead. Indirect construction overhead costs are those costs that are not easily identifiable to a specific Work Request (WR). The Uniform System of Accounts defines qualifying indirect construction overhead as the costs of engineering, general supervision, appropriate general office salaries and expenses, charges by others for construction engineering and supervision, and other related expenses such as legal, insurance, injuries and damages, pensions, taxes, etc. Refer to the Construction Overhead Costs vs. Operation and Maintenance Costs section for examples of typical indirect construction overhead costs. In some instances, these costs may be directly charged to a project and not flow through the indirect construction overhead process.

Outside supervision or engineering costs related to a specific project should be charged directly to the individual WR. This WR will additionally receive indirect construction overhead loading.

Procedure

Accounting For Charges to Indirect Construction Overhead

Indirect construction overhead costs are charged to the appropriate indirect construction overhead project based on the business unit (see below). These charges are allocated monthly via an automated clearing process. Allocations are based on a calculated indirect construction overhead rate, with indirect construction overhead costs allocated to all open capital WRs (refer to Allocation of Indirect Construction Overhead).

The account distribution to allocate charges from the specified indirect construction overhead WR is as follows:

DR/CR	BU	Project #	EC	Amount
DR	ESD	valid capital WRs	870	$xxx.xx
CR	ESD	INCONOHE	870	$(xxx.xx)

Indirect Construction Overhead Projects

Project	BU
INCONOHE	ESD
INDCONOH	TRN

The information below provides guidance on how various types of indirect construction overhead charges should be apportioned.

Labor and Labor Loading

For those employees on fixed labor distribution who support both O&M expense and construction activities; and, whose work is associated with so many individual construction projects and that it is unrealistic to charge each project individually can assign a portion of their labor expense to indirect construction overhead. Labor and associated payroll loadings are charged to indirect construction overhead based on the percentage of employees' time devoted to construction related tasks. Each employee, based on assignment of duties, is responsible for identifying the appropriate number of hours worked on construction-related projects. The allocation of supervisory personnel labor costs are based on the composite payroll ratio of the employees reporting to them.

The payroll distribution for each employee should be reviewed and adjusted quarterly or sooner if there is a change in the allocation percentage supporting capital work activities. An employee's manager or supervisor is responsible for:

- Identifying the individuals who are supporting construction work activities
- Determining the appropriate allocation percentage between O&M and capital activities
- Ensuring that the percentages reasonably reflect the time spent by employees on capital and O&M activities, and
- Making timely updates to the allocation percentages when there is an increase or a reduction in construction related activities.
- Ensuring that the appropriate updates to labor allocation percentages are made in both ePeople as well as the PeopleSoft Expense module.

Quarterly, Oncor Financial Support will send out e-mails to all managers and supervisors reminding them to review the allocation percentages of each of their employees for the appropriate split between capital and O&M related work.

Oncor Financial Support is available to assist managers and supervisors in determining the appropriate allocation percentage, and can also assist with any necessary updates in ePeople and the PeopleSoft Expense module. The Payroll Distribution Form contained within this policy, though not mandatory, is a tool that may be used to help determine and support the appropriate capital percentage

Material

All material costs pertaining to construction project materials must be charged directly to a specific capital WR, and not to the indirect construction overhead projects.

Software

Refer to Accounting Policy 50-06, Software Capitalization.

Other Costs

Other costs such as data processing, rents, utilities, and office supplies for a region, department, or service center are charged based on the composite payroll ratio for that area. Employee expenses such as transportation and other reimbursable expenses are charged based on the employee's payroll distribution.

Allocation of Indirect Construction Overhead

The indirect construction overhead charged to the various indirect construction overhead projects is allocated monthly to all loadable capital projects. This allocation is applied based on functionalized rates, using expenditure code 870. It is the responsibility of Property Accounting to monitor and calculate the indirect construction overhead rates.

The formula to calculate the functional indirect construction overhead rate is as follows:

(Current indirect construction overhead balance + current year's projected remaining indirect construction overhead additions) *divided by* Current year's projected remaining loadable construction expenditures. Loadable construction expenditures represent the CAPEX spend for labor, materials and other direct cost supporting construction activities less contribution in aid of construction (CIAC), general plant, and intangible costs.

The applied rate should yield a projected year-end indirect construction overhead balance that is reasonable and acceptable to the Controller or his designee.

The indirect construction overhead amount applied to each valid capital WR is calculated as follows:

Current month's functional indirect construction overhead rate *times* Current month's loadable construction expenditures.

The indirect construction overhead rates are monitored monthly to ensure that an appropriate amount of indirect construction overhead is being allocated. If it is determined that the actual indirect construction overhead charges and actual loadable construction expenditures for the year-to-date or the estimated indirect construction overhead charges and the estimated loadable construction expenditures for the remainder of the year have changed significantly, the indirect construction overhead rate will be changed accordingly.

The ESD meter blanket projects are charged an indirect construction overhead loading rate that is different from the loading rate applied to all other loadable capital projects. Labor and associated costs are charged directly to these blanket projects; none of the labor costs charged to the indirect construction overhead are applicable to the meter blanket projects. This loading rate is reviewed annually.

Note: Charges manually transferred to a WR with a journal entry other than an original source requires a manual calculation and recording of indirect construction overhead.

Construction Overhead Costs vs. Operation & Maintenance Costs

The following serves as an aid in identifying indirect construction overhead costs versus operation and maintenance costs:

ONCOR.

Indirect Construction Overhead Costs

1. Planned Construction Program - Costs incurred in connection with specific WRs and general activities such as:

   - Design (including preliminary engineering and studies directly related to specific WRs).
   - Detailed estimates of costs.
   - Detailed drawings.
   - Scheduling of manpower requirements.
   - Special instructions.
   - Preparation of WR's.
   - Feasibility studies directly related to the construction program or that results in a capital WR.
   - Cost trend studies on items such as materials, labor, and transportation relating to capital WRs.
   - Development of standards to be used in capital WRs.

   ***Note**: Research, development, and demonstration costs are charged to expense. Please refer to Accounting* Policy 50-03, Research, Development, and Demonstration Projects.

2. Approved WR's - Costs incurred after the project has been approved, including the preparation and processing of:

   - Detail specifications.
   - Bids and/or contracts
   - Requisitions for special materials found in WRs with project type = PRELM (Preliminary).

3. Supervising Construction Work - Costs incurred in the general supervision of construction work. Direct supervision by line management should be recorded as a direct construction cost.

4. Monitoring WR Expenditures - Costs incurred in monitoring WR expenditures during construction.

5. Reviewing Completed WR's - Costs incurred after construction is complete. Such costs include:

   - Field checking and reporting of work completed.
   - Posting of charges to WR's and the final review of these charges associated with closing WR's to Plant in Service.
   - Reviewing and analyzing the projects to assure that Engineering requirements were met and that charges are consistent with the work performed.

6. Preliminary Work - Costs incurred from preliminary surveys, estimates, and negotiations with present and prospective customers concerning the availability and extension of service. Preliminary WRs can be used, if applicable, to account for preliminary work that ultimately results in a construction WR. Otherwise, these activities are expense.

7. Construction Budgeting - Costs of compiling information necessary to enable selection and sequencing of construction WRs. Such costs include:
   - General engineering
   - General cost estimates
   - Summarization of budget information.
   - Preparation of expenditure forecasts.
   - Preparation of construction budgets.
8. Employee labor to purchase Land and Land Rights

9. Training of Employees - Cost of training is capitalized when the training is to teach employees to operate or maintain assets that are being constructed when such assets are not conventional in nature or are new to the Company's operations
   - When these facilities are placed in service, the capitalization of training costs ceases and subsequent training costs are expensed.
   - General training (such as safety and first aid) should be charged to expense (Reference Operation and Maintenance Costs).

10. Salary Incentive Plans - portion of Salary Incentive Plans that are considered wages and compensations and that are applicable to personnel whose base labor is charged to construction activities

    - Employee Bonuses (EC 111)
    - Annual Incentive Plans (EC 114)
    - Deferred and Incentive Compensation (EC 115)
    - Salary Deferral (7 yr. option) (EC 116)
    - Salary Deferral – Retirement (EC 117)
    - Long Term Incentive Compensation Plan (EC 325)

11. Rent/Office Supplies - Costs are charged based on the composite payroll ratio for that area.

    - Leased PCs/Computer Equipment
    - Rents/Leases
    - Utilities
    - Break Room Supplies
    - General Office Supplies
    - Janitorial – cleaning services
    - Security
    - Routine lawn care
    - Telephone/Telecommunication Services
    - Leased Printers/Copiers

12. Contractor Incentives and rebates – portion applicable to construction activities

13. Employee Expenses – Employees expenses are assigned based on the employee's normal labor distribution with the exception of Social Club Dues and Fees and Employee Appreciation expense which should always be charged to Operation and Maintenance.

14. Outsourcing Activities – portion of cost providing a benefit to or support of construction activities
    - Information Technology
    - Accounting
    - Procurement

    Note: Outsourced Procurement activities generally should be charged to stores clearing accounts and distributed through common loading process.

15. Postage and Shipping associated with construction activities

16. Consulting related to engineering designs and construction activities

17. Licensing fees for systems that support the construction process. These systems are used in the design, estimation of cost, requesting material, scheduling resources, updating maps, and other related construction activities.

<u>Operation and Maintenance Costs</u>

1. Feasibility Studies - Costs incurred in the study of new concepts and the development of new methods and procedures for maintenance and/or operation programs of the Company.

2. Cost Trend Studies - Costs incurred in the development of cost trends relating to operation and maintenance.

3. Development of Standards - Costs incurred in the development, implementation, and maintenance of standards for all types of maintenance and/or purchases transmission plant, distribution plant, and general plant.

4. System Planning - Costs incurred in developing plans to meet future system demand and energy requirements.

5. Training of Employees - Costs incurred for general training (such as safety and first aid). For other training costs, refer to Construction Overhead Costs, Number 9.

6. Updating/Correction of Map Records Outside of the Normal WR Completion Process - Costs not related to the completion of the WR process including:

    - Map Corrections – Updating maps to reflect "found" assets, GLN corrections
    - Updating other files and records such as transmission and distribution files, meter files, and equipment inventories.

7. Abandoned and Canceled WRs - Costs incurred in connection with abandoned and canceled WRs.

8. Reporting - Costs of accumulating and reporting construction data and statistics to groups such as management, shareholders, regulatory authorities, tax authorities, mortgage trustees, and industry organizations.

9. Employee Expenses – Refer to Item 13 under Indirect Construction Overhead Costs

    - Social Club Dues and Fees (EC 303)
    - Employee Appreciation (EC 312)

10. Building Repairs and Services related to General Plant **(Reference Facility and Shared Services)**

11. Equipment Maintenance and Services

12. Shipping/Postal Expenses non-construction related. Freight related to inventory should be charged to purchasing and stores expense.

13. Miscellaneous Expenses (EC 900) – construction overhead charges should be assigned a specific EC

14. Advertisements – should be charged to Account 930.1000

15. Political or other legislative advocacy costs – should be charged to Account 426.4500

16. Charitable Contributions (EC 842) – should be charged to Account 930.2000.

17. Legal Costs not associated with a construction project (if related to a construction project, the cost should be charged directly to the WR

18. Meals with Union Officials

19. Consulting related to organizational design or other non-capital activities

20. Market Research not associated with a Planned Construction Program (Item #1 Indirect Construction Overhead Cost)

21. Company Membership Dues and Fees (EC 841) – should be charged to Account 930.2000

Facility Projects

Facility projects capture the costs of operating a facility in order to functionalize lease and ongoing general maintenance expense to the occupants of a facility. Costs are allocated between multiple departments, Construction Overhead, O&M and Purchasing and Stores Overhead. Because a portion of the facility cost is capitalized via construction overhead; costs charged to a facility project can only be those costs identified under the section Indirect Construction Overhead Costs; and, directly related to the operation of a company facility. Operation and maintenance costs such as repairs to a facility cannot be charged to a facility project. General plant property units, such as chairs, desks, cabinets, computer software, etc. may not be charged to a facility project. General plant items are accounted for in accordance with instructions contained in the Capital Maintenance Policy

Shared Services Projects ("A" Projects)

Shared services projects are used to capture the cost of organizations that support multiple utility functions. Costs are allocated to the appropriate BU between Construction Overhead and O&M. Since a portion of the cost charged to the shared service gets allocated to construction overhead, charges to shared service projects must also conform to section indirect Construction Overhead Costs. These costs should be directly related to the operation of a shared department. In addition, operation and maintenance costs such as repairs cannot be charged to the shared service project. Units of property for general plant should not be charged to the shared service project. General plant items should be accounting for in accordance with the instructions contained in the Capital Maintenance Policy.

The following items should **NOT** be charged to Construction Overhead but should be charged to a specific WR if capital related

1. Billed Contributions in Aid of Construction
2. Plant Relocation Reimbursements (non-accrued)
3. Rubber Good Material
4. Miscellaneous Expenses (cost should be clearly identified if charged to construction overhead)
5. Direct construction crew labor
6. Direct construction contractor costs
7. Storm related costs
8. Metering Administrative and Overhead Costs – these costs should be charged directly to the current year's meter blankets.
9. General plant items not meeting the capitalization criteria. General Plant items meeting the capitalization criteria should be charged directly to a general plant WR.
10. The labor and associated costs of employee on variable labor distribution.

Revision History

February 2, 2010	Adoption of Oncor policy
August 10, 2010	Clarification of Financial Support and Management's Responsibilities
January 27, 2015	Attached copy of Payroll Distribution Form
April 20, 2016	Reviewed for update – minor edits made.
December, 1, 2016	Updated Payroll Distribution Form link.
August 6, 2018	Added section on Facility and Shared Services Projects and updated/clarified appropriate charges to COH

http://intranet.corp.oncor.com/sites/Finance/controller/Documents/APP%20Policies/Payroll Distribution Form.xlsx

March 9, 2021	Reviewed for updates – minor edits made

Testimony Glossary of Abbreviations

Abbreviation	Description	Page Defined
4CP	Refers to the average of the 15-minute maximum system coincident peak load demand for the ERCOT system for the months of June, July, August, and September of the preceding calendar year	86
2017 Asset Exchange	Refers to the November 2017 asset exchange transaction between Oncor and SDTS arising from the Docket No. 46957 settlement	37
A&G	administrative and general	76
ADIT	accumulated deferred income taxes	19
AFUDC	Allowance for Funds Used During Construction	28
AMS	advanced metering system	41
ASC	Accounting Standards Codification	18
ASU	Accounting Standards Update	20
C&I	commercial and industrial	25
CIAC	contributions in aid of construction	111
COH	Other Construction Overhead	28
Commission	Public Utility Commission of Texas	7
(the) Company	Oncor Electric Delivery Company LLC	6
COVID-19	Coronavirus Disease 2019	18
CWC	cash working capital	70
CWIP	construction work in progress	29
DCRF	Distribution Cost Recovery Factor	20
DC-Ties	Direct-Current interconnections with areas outside of the ERCOT region	35
Dept ID	department identification code	46
DIST	Distribution business function	30
EAIP	Executive Annual Incentive Plan	92
EECRF	Energy Efficiency Cost Recovery Factor	25
EPHFU	Electric Plant Held for Future Use	33
EPIS	Electric Plant in Service	33
ERCOT	Electric Reliability Council of Texas, Inc.	13
ERP	Electricity Relief Program	59
FASB	Financial Accounting Standards Board	18
FERC	Federal Energy Regulatory Commission	8
FERC A###	FERC USOA Account No. ###	8
financial statements	Consolidated balance sheets of Oncor and its subsidiaries, the related consolidated statements of income, comprehensive income, cash flows, and membership interests, and the related notes to consolidated financial statements	10

Testimony Glossary of Abbreviations

Abbreviation	Description	Page Defined
FICA	Federal Insurance Contribution Act	92
FIT	federal income tax	74
InfraREIT	InfraREIT, Inc. and its subsidiary InfraREIT Partners, LP	13
InfraREIT Acquisition	Refers to Oncor's acquistion of all of the equity interests of InfraREIT, Inc. and its subsidiary InfraREIT Partners, LP, which was approved by the Commission in Docket No. 48929.	13
Interconnection Plan	Refers to a joint project involving the build out of approximately 175 miles of transmission lines and associated station work to join the City of Lubbock to the ERCOT market, with final ownership of the resulting assets being equally shared between Oncor and LP&L	38
long-lead-time assets	Refers to transmission and distribution facilities that have a lead time of at least six months and that would aid in restoring power to a utility's distribution customers following a widespread power outage event	44
LP&L	Lubbock Power & Light	16
LTIP	Long-Term Incentive Plan	93
M&S	materials and supplies	23
MET	Transmission and Distribution Utility Metering System Services business function	30
MW	Megawatts	86
NESC	National Electrical Safety Code	61
NSC	non-service cost components of net periodic pension and other postretirement costs	23
NTS	Network Transmission Service	86
O&M	Operation and Maintenance	15
OCI	Other Comprehensive Income	52
Oncor	Oncor Electric Delivery Company LLC	6
Oncor Holdings	Oncor Electric Delivery Holdings Company LLC	12
Oncor NTU	Oncor Electric Delivery Company NTU LLC	12
OPEB	other postemployment benefit	24
PEP	Performance Enhancement Plan	90
PLSA	William Thomas Heath Power Line Safety Act	61
PP&E	Property, Plant, and Equipment - net	33
PURA	Public Utility Regulatory Act, Texas Utilities Code, Title 2 (as amended)	12
REPs	retail electric providers	31
RFP	Rate Filing Package	8
ROU	right-of-use	21

Testimony Glossary of Abbreviations

Abbreviation	Description	Page Defined
SBC	Stanton, Brady, and Celeste divisions	65
SDTS	Sharyland Distribution & Transmission Services, L.L.C.	12
SEC	United States Securities and Exchange Commission	10
SEC Form 10-K	Form 10-K -- Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934	11
Sempra	Sempra Energy	12
Sharyland	Sharyland Utilities, L.L.C.	17
SPP	Southwest Power Pool	36
SPS	Southwestern Public Service Company	36
SU	Sharyland Utilities, L.P.	13
T&D	Transmission & Distribution	9
TAC	Texas Administrative Code	10
TBILL	Transmission and Distribution Utility Billing System Services business function	30
TCJA	2017 Tax Cuts and Jobs Act	64
TCOS	Transmission Cost of Service	20
TCRF	Transmission Cost Recovery Factor	25
TDCS	Transmission and Distribution Utility Customer Service business function	30
TDU	Transmission & Distribution Investor-Owned Utility	30
Topic 842	FASB Topic 842, "Leases"	20
TRAN	Transmission business function	30
TRP	Telecommunications Refresh Program	42
TSA	Tax Sharing Agreement between Oncor, Oncor Holdings, Sempra Texas Holdings Corp., and TTI	19
TTI	Texas Transmission Investment LLC	12
US GAAP	Generally Accepted Accounting Principles in the United States of America	7
USOA	Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act	8
WDSS	wholesale distribution substation service	59
WNF Line	Wadsworth to New Oliver to Farmland 345-kV transmission line	39

2022 RATE CASE
ONCOR ELECTRIC DELIVERY COMPANY LLC
WORKPAPERS FOR
THE DIRECT TESTIMONY OF
W. ALAN LEDBETTER

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

Testimony Workpapers/Ledbetter

Ledbetter Direct Testimony Workpapers.xlxs

2022 Rate Case
Oncor Electric Delivery Company LLC
Sch II-B Col (d) Known & Measurable Adjustments Line 23 - Summary
For the Test Year Ending December 31, 2021
Sponsor: W. Alan Ledbetter

	Rate base	Sch II-B K&M Adjustments Col (d) Line Reference	Schedule reference or note
Sch II-B Col (d) Known & Measurable Adjustments Line 23	$ 340,681,042		
Plant in service			
Exclusion of assets pending transfer to LP&L (Docket No. 52726)	$ (4,733,186)		
Exclusion of transportation assets (aviation)	$ (4,277,641)		
Exclusion of certain 777 Main leasehold improvements	$ (19,251,400)		
Retirement of Electric Service Building leasehold improvements	$ (10,713,503)		
Total plant in service exclusions	$ (38,975,731)	Line No 4	
Minus Accumulated depreciation			
Exclusion of assets pending transfer to LP&L (Docket No. 52726)	$ (81,612)		
Exclusion of transportation assets (aviation)	$ (1,197,272)		
Exclusion of certain 777 Main leasehold improvements	$ (1,290,597)		
Retirement of Electric Service Building leasehold improvements	$ (10,713,503)		
Total accumulated depreciation exclusions	$ (13,282,984)	Line No 6	
Net plant in service	$ (25,692,747)	Line No 8	
CWIP - rate base exclusion	$ (558,881,688)	Line No 11	Sch II-B-5
Plant Held for Future Use - construction window beyond 2031	$ (3,485,638)	Line No 12	Sch II-B-6
Materials & Supplies	$ (190,712)	Line No 14	Sch II-B-8
Other rate base items - K&M adjustment for construction-related customer cash deposits set aside in escrow	$ 42,876,848	Line No 17	Sch II-B-11
Regulatory assets known & measurable adjustments:			
Exclusion of debt-related regulatory asset & liability (net liability)	$ 6,632,575		Sch II-C-2.4 and II-C-2.4a
K&M adjustment COVID19 regulatory asset	$ (41,176)		Sch II-B-12
K&M adjustment PLSA regulatory asset	$ (34,165)		Sch II-B-12
K&M adjustment REP Default regulatory asset	$ (530,633)		Sch II-D-2.2a
Rate Case Expenses - Test Year 2021 Base Rate Case regulatory asset	$ 3,278,710		Sch II-E-4.5
Exclusion of TCRF under-recovery regulatory asset	$ (58,314,504)		Sch II-B-12
Estimated net removal costs regulatory liability (GAAP) regulatory asset	$ 1,348,181,167		See note below regarding GAAP reclass from accumulated depreciation to regulatory liability
Exclusion of Pension & OPEB Reg Asset-ONCOR (GAAP) regulatory asset	$ (328,914,729)		Sch II-B-12
CWIP Tran & Dist Non-Service Cost Pension/OPEBs (GAAP) regulatory asset	$ (1,968,953)		GAAP reclass from CWIP to regulatory asset; for rate case, reclass excluded.
Plant in service Tran & Dist Non-Service Cost Pension/OPEBs (GAAP) regulatory asset	$ (114,751,835)		GAAP reclasses from net plant to regulatory asset; for rate case, reclasses excluded.
Exclusion of unbilled revenue deferrals (regulatory liabilities for TCRF & AMS (GAAP))	$ 66,561,736		Sch II-B-12 Line Nos 43-44
Exclusion of Workers Compensation regulatory asset	$ (8,098,712)		Sch II-B-12
Exclusions of EECRF regulatory asset net of liability	$ (32,223,580)		Sch II-B-12 Line Nos 32 and 41
Exclusion of Interest-rate Savings regulatory liability (Dkt 47675 & 53320-pending refund)	$ 1,946,863		Sch II-B-12
Exclusion of Rate Case Expenses - Non-std Metering Tariff (Dkt 41890)	$ (23,799)		Sch II-B-12
K&M adjustments non-tax-related regulatory asset/liabilities	$ 881,698,964		
K&M adjustments tax-related regulatory asset/liabilities	$ 287,756,040		Sch II-B-12
K&M adjustments regulatory asset/liabilities	$ 1,169,455,005	Line No 18	
Accumulated Deferred Income Taxes	$ (283,400,025)	Line No 19	Sch II-E-3.5
Total Known & Measurable Adjustments on Sch II-B Column (d) Line No 23	$ 340,681,042		

Accumulated depreciation (Sch II-B-5) includes estimated net removal costs for Total Company. For GAAP, estimated net removal costs are reclassed from accumulated depreciation to the regulatory liability. For rate case, GAAP reclass is excluded.

2022 Rate Case
Oncor Electric Delivery Company LLC
Support for Adjusted T&D Electric - Plant-related Items
For the Test Year Ending December 31, 2021
Sponsor: W. Alan Ledbetter

	10-K	Balance sheet	Exclude GAAP reclasses NSC pension/OPEBs & cap leases	Include GAAP reg. liability Estimated removal costs	Exclude SARs Account 116	Reclass Account 114 Acquisition Adjustments	II-B Col C Regulated T&D	II-B Line No	II-B Col D Incl. K&M Adjustments	II-B Col E Adjusted T&D Electric	II-B Line No	
Plant in service	$31,029	$ 31,028,654,855	$ (123,130,828)		$ 6,522,878	$ 21,907,074	$ 31,123,355,731	Line No 4	$ (38,975,731)	$ 31,084,380,001	Line No 4	
less acc. depr. Reserve	$ 8,659	$ 8,658,878,685	$ (5,232,845)	$ 1,348,181,167			$ 10,012,292,697	Line No 6	$ (13,282,984)	$ 9,999,009,713	Line No 6	
Net plant	$22,370	$ 22,369,776,171	$ (117,897,983)	$ (1,348,181,167)	$ 6,522,878	$ 21,907,074	$ 21,111,063,034	Line No 8	$ (25,692,747)	$ 21,085,370,288	Line No 8	
CWIP	$ 557	$ 556,912,735	$ (1,968,953)				$ 558,881,688	Line No 11	$ (558,881,688)	$ -	Line No 11	Rate base exclusion
EPHFU	$ 27	$ 26,700,685					$ 26,700,685	Line No 12	$ (3,485,638)	$ 23,215,048	Line No 12	Exclusion where construction window beyond 2031
Total	$22,954 $millions	$ 22,953,389,591	$ (119,866,936)	$ (1,348,181,167)	$ 6,522,878	$ 21,907,074	$ 21,696,645,408		$ (588,060,073)	$ 21,108,585,335		
				Shown as other rate base on II-B-12 Line No 40	Shown as other rate base on II-B-11 Line No 6 Rate base exclusion	Shown as other rate base on II-B-11 Line Nos 3-5						

Plant in service excl. intangible	$ 29,962,304,574
Intangible software	$ 1,066,350,281
Plant in service	$ 31,028,654,855
Plant in service excl. intangible	$ 8,208,111,604
Intangible software	$ 450,767,081
Acc. depr. reserve	$ 8,658,878,685
Plant in service excl. intangible	$ 21,754,192,970
Intangible software	$ 615,583,201
Net plant	$ 22,369,776,171

Mobile gens - GAAP oper leases	$ (3,146,147)
NSC P/O reg asset net plant	$ (114,751,835)
NSC P/O reg asset CWIP	$ (1,968,953)
Total credits	$ (119,866,936)

Plant in service		
Exclusion of assets pending transfer to LP&L (Docket No. 52726)		$ (4,733,186)
Exclusion of transportation assets (aviation)		$ (4,277,641)
Exclusion of certain 777 Main leasehold improvements		$ (19,251,400)
Retirement of Electric Service Building leasehold improvements		$ (10,713,503)
Total		$ (38,975,731)
Accumulated depreciation		
Exclusion of assets pending transfer to LP&L (Docket No. 52726)		$ 81,612
Exclusion of transportation assets (aviation)		$ 1,197,272
Exclusion of certain 777 Main leasehold improvements		$ 1,290,597
Retirement of Electric Service Building leasehold improvements		$ 10,713,503
Total	Flip sign	$ 13,282,984
Net plant Known & Measurable adjustment		$ (25,692,747)

II-B-11 acquisition adjustments

TRAN	1141000 Plt Acq Adj - Andrews Cnty Line	(previously reviewed and approved)	$ 720,668
DIST	1142000 Plt Acq Adj - Sharyland	(previously reviewed and approved)	$ (2,266,261)
NTU	1143000 Plt Acq Adj - SPS	(to be reviewed)	$ 23,452,667
			$ 21,907,074

2022 Rate Case
Oncor Electric Delivery Company LLC
Total Membership Interests (Common Equity)
For Test Year Ending December 31, 2021
Sponsor: W. Alan Ledbetter

	10-K ($millions)
Total membership interests (common equity)	$ 12,588

	Sch II-C-2.1 Balance at December 31, 2021	Exclude OCI loss	Exclude the effects of the 2007 merger (Docket No. 34077 commitments)	Exclude equity supporting goodwill - Oncor's acquisition of NTU (Docket No. 48929)	Sch II-C-2.1 Proforma Adjustments	Sch II-C-2.1 Proforma Balance
Total membership interests (common equity)	$ 12,587,083,868	$ 131,445,566	$ (3,833,066,268)	$ (676,053,911)	$ (4,377,674,612)	$ 8,209,409,256

2022 Rate Case - O&M
Oncor Electric Delivery Company LLC
O&M Expense
Test Year Ending December 31, 2021
Sponsor: W. Alan Ledbetter

O&M Expense - Sch I-A-1 Regulated T&D Electric (c)Line 1

	Account	Total Company	Include test year Oncor billing for NTS expense	Include test year NTU billing for NTS expense	Sch II-D-1 Total Company Col (d), Line No 8	
Wholesale transmission service	565	$ 1,038,649,215	$ 398,122,465	$ 80,434,328	$ 1,517,206,008	a
10-K 2021 Wholesale transmission service		$1,039 million	TSP affiliate billing to DSP	NTU TSP affiliate billing to DSP		

	Accounts	Total Company	Exclude GAAP NSC Pension & OPEBs	Include Oncor TRAN billing to NTU TRAN	Sch II-D-1 & II-D-2 Total O&M excl. Account 565	
Operation and maintenance expense excluding wholesale transmission service	560-935	$ 982,464,177	$ (50,944,520)	$ 9,588,988	$ 1,042,997,684	b
	Excl. 565		See note 1			
10-K 2021 Operation and Maintenance		$983 million				

	Sch II-D-2 Total Company Col (d), Line No 21		Sch I-A-1 Regulated T&D Electric Col (c) Line 1
Total O&M Accounts 560-935	$ 2,560,203,692	= a + b	$ 2,560,203,692

Note 1: Non-service costs for pension and OPEBs are reclassed from benefit expense (account 926) to non-operating other deductions for GAAP. Exclude GAAP reclass or O&M credit.

2022 Rate Case
Oncor Electric Delivery Company LLC
Depreciation and Amortization Expense
Test Year Ending December 31, 2021
Sponsor: W. Alan Ledbetter

D&A Expense on Sch I-A-1 Regulated T&D (c)Line 2

	Account	Total Company	Exclude GAAP NSC Pension & OPEBs	Regulated Total Company	Exclude Correction for prior years	Exclude Correction 2021 test year	Sch II-E-4 Total Co Include Interest on Customer Deposits	Sch II-E-1 Total Company Col (d)
Depreciation expense	403	$ 775,812,228	$ (2,100,089)	$ 777,912,318	$ -	$ -	$ -	$ 777,912,318
Amortization expense - intangibles	404	44,669,289	-	44,669,289	(16,643,733)	(5,160,320)	-	66,473,342
Depreciation & Amortization Expense (Line No 59)		$ 820,481,518	$ (2,100,089)	$ 822,581,607	$ (16,643,733)	$ (5,160,320)		$ 844,385,660
Amortization expense - Account 114 acquisition adjustments	406	$ (30,674)	$ -	$ (30,674)	$ -	$ -	$ -	$ (30,674)
Misc. Other Expenses - Interest on Customer Deposits	431	-	-	-	-	-	228,869	228,869
Depreciation & Amortization Expense (Line No 64)		$ 820,450,844	$ (2,100,089)	$ 822,550,933	$ (16,643,733)	$ (5,160,320)	$ 228,869	$ 844,583,856
			See note 2		See note 3	See note 4		Sch I-A-1 Regulated T&D Electric Col (c) Line 2

10-K Depreciation and amortization $820 million

Note 2: For GAAP, non-service costs for pension and OPEBs reclass of depreciation expense to non-operating as regulatory asset amortization. Exclude depreciation credit.
Note 3: Remove correction (credit in test year amortization expense) of over-amortization of intangibles applicable to years prior to the test year (2012 - 2020).
Note 4: Remove correction (credit in test year amortization expense) of over-amortization of intangibles for 2021 test year.

2022 Rate Case
Oncor Electric Delivery Company LLC
Depreciation and Amortization Expense
For Test Year Ending December 31, 2021
Sponsor: W. Alan Ledbetter

	Account	Depreciation & Amortization Expense		D&A Expense K&M Adjustments
Depreciation expense	403	$ 777,912,318		
Amortization expense - intangibles	404	$ 66,473,342		
Depreciation & Amortization Expense - as adjusted (Sch II-E-1 Regulated T&D Electric Column (f) Line 59)		$ 844,385,660	(a)	
Depreciation & Amortization Expense - as adjusted (Sch II-E-1 Regulated T&D Electric Column (f) Line 59)		$ 844,385,660	(a)	
Plus depreciation & amortization expense - 12-31-2021 plant depreciated & amortized a full year		44,046,875		44,046,875
Depreciation & Amortization Expense - as adjusted		888,432,535		
Less depreciation expense for assets pending transfer to LP&L		(475,155)		(475,155)
Less amortization expense for ESB leasehold improvements (lease ends 2022)		(190,700)		(190,700)
Less depreciation expense (transportation) for aviation assets		(393,543)		(393,543)
Adjusted full-year depreciation and amortization expense for 12-31-2021 plant		887,373,137		
Lower amortization expense - intangibles in life groups proposed in this case (3-year, 5-year, 8-year, and 15-year)		(9,428,285)		(9,428,285)
Lower depreciation expense - depreciation of NTU assets consistent with Oncor for transmission assets *		(4,119,648)		(4,119,648)
Lower depreciation expense - depreciation of NTU assets consistent with Oncor for distribution assets *		(138,836)		(138,836)
Lower depreciation expense - distribution		(44,096)		(44,096)
Lower depreciation & amortization expense - reflects fully accrued assets (transportation, communication, general plant)		(6,825,181.48)		(6,825,181)
Subtotal depreciation and amortization expense		866,817,090		
Proposed annual depreciation and amortization expense accrual increase - Depreciation Study		21,618,193		
Proposed annual depreciation and amortization expense accrual increase - Depreciation Study - general plant reserve imbalance over eight years		12,475,110		
Proposed annual depreciation and amortization expense accrual		34,093,303		34,093,303
Depreciation and amortization expense requested in this case (Sch II-E-1 Adjusted Regulated T&D Column (h) Line 59)		**$ 900,910,393**		
Known & Measurable Adjustments (Sch II-E-1 Column (g) Line 59)				56,524,733

* NTU transmission and distribution assets were depreciated during the test year consistent with NTU's Tariff WTS and Tariff WDSS.

INDEX TO THE DIRECT TESTIMONY

OF DANE A. WATSON, WITNESS FOR

ONCOR ELECTRIC DELIVERY COMPANY LLC

DIRECT TESTIMONY OF DANE A. WATSON

I. POSITION AND QUALIFICATIONS

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

A. My name is Dane A. Watson. My business address is 101 E. Park Blvd, Suite 220, Plano Texas 75074. I am a Partner of Alliance Consulting Group ("Alliance"). Alliance provides consulting and expert services to the utility industry.

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. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I hold a Bachelor of Science degree in Electrical Engineering from the University of Arkansas at Fayetteville and a master's degree in Business Administration from Amberton University.

Q. HAVE YOU EVER SUBMITTED TESTIMONY BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS ("COMMISSION")?

A. Yes. I have conducted depreciation studies and filed testimony on depreciation and valuation issues before the Commission in Docket Nos. 11735, 12160, 15195, 16650, 18490, 20285, 22350, 23640, 24040, 32766, 34040, 35763, 35717, 36633, 38147, 38339, 38480, 38929, 40020, 40604, 40606, 40824, 41474, 42004, 42469, 43695, 43950, 44746, 44704, 45414, 46957, 47527, 48371, 48231, 48401, 49421, 49831, 50288, 50557, 50944, 51536. 51611, and 51802 among others. In addition, I have testified on behalf of various entities in more than 290 proceedings before more than 35 different regulatory bodies in my 37-year career of performing depreciation studies. My Exhibit DAW-1 lists instances in which I have conducted depreciation studies, filed written testimony, and/or testified live before various regulatory commissions.

Q. DO YOU HOLD ANY SPECIAL CERTIFICATION AS A DEPRECIATION EXPERT?

A. Yes. The Society of Depreciation Professionals ("SDP") has established international standards for depreciation professionals. The SDP administers an examination and has certain required qualifications to become certified in this field. I have met all requirements and am a Certified Depreciation Professional ("CDP").

Q. PLEASE OUTLINE YOUR EXPERIENCE IN THE FIELD OF DEPRECIATION.

A. Since graduating from college in 1985, I have worked in the area of depreciation and valuation. I founded Alliance in 2004 and am responsible for conducting depreciation, valuation, and certain accounting-related studies for utilities in various industries. My duties related to depreciation studies include the assembly and analysis of historical and simulated data, conducting field reviews, determining service life and net salvage estimates, calculating annual depreciation, presenting recommended depreciation rates to utility management for its consideration, and supporting such rates before regulatory bodies.

My prior employment from 1985 to 2004 was with TXU Corp. and its predecessors ("TXU"). During my tenure with TXU, I was responsible for, among other things, conducting valuation and depreciation studies for the domestic TXU companies. During that time, I also served as Manager of Property Accounting Services and Records Management in addition to my depreciation responsibilities.

I have twice been Chair of the Edison Electric Institute ("EEI") Property Accounting and Valuation Committee and have been Chairman of EEI's Depreciation and Economic Issues Subcommittee. I am a Registered Professional Engineer ("PE") in the State of Texas and a CDP. I am a Senior Member of the Institute of Electrical and Electronics Engineers ("IEEE") and have held numerous offices on the Executive Board of the

Dallas Section of IEEE as well as national and worldwide offices. I have twice served as President of the SDP, most recently in 2015. I also teach depreciation seminars on an annual basis for EEI and the American Gas Association (both basic and advanced levels), and I develop and teach the advanced training for the SDP and other venues.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to:

- discuss the recent depreciation study completed for Oncor assets; and
- support and justify the recommended depreciation rate changes for Oncor assets based on the results of the depreciation study.

The depreciation study is provided as Exhibit DAW-2 to my direct testimony.

Q. HAS THE COMPOSITION OF ONCOR'S ASSETS CHANGED SINCE THE LAST DEPRECIATION STUDY?

A. Yes. In Oncor's last base-rate case, Docket No. 46957, the Commission's Order was predicated on Oncor and the company known at that time as Sharyland Distribution & Transmission Services, L.L.C. ("Sharyland") reaching closing on a transaction to exchange assets (Oncor was to acquire primarily distribution assets, while Sharyland was to receive certain Oncor transmission assets). The Sharyland transaction did close, and the asset exchange took place in 2017. This transaction is discussed in greater detail in Company witness Mr. James A. Greer's direct testimony. Also, Oncor's distribution facilities in the McAllen and Mission, Texas area that were acquired in the asset exchange were sold to AEP Texas Inc. for net book value with no gain or loss arising from the sale. As a result, there was no impact on my depreciation analysis related to this transaction.

Additionally, as described in greater detail in the direct testimony of Oncor witness Mr. Wesley R. Speed, in 2019, the Commission approved a transaction in Docket No. 48929 that resulted in Oncor's acquisition of the electric transmission assets previously held by Sharyland and/or Sharyland Utilities, L.P. Following the close of that transaction, Sharyland became a wholly-owned subsidiary of Oncor, Oncor Electric Delivery Company NTU LLC ("Oncor NTU"), and continues to hold those assets. Those assets now held by Oncor NTU include mostly transmission, distribution, and general plant. The Oncor NTU assets are currently being depreciated at the depreciation rates approved for Sharyland in Docket No. 45414, which retained the then-existing depreciation rates from Docket No. 41474.

Q. HOW ARE THE ASSETS HELD BY ONCOR NTU TREATED IN THIS DEPRECIATION STUDY?

A. At Oncor's request, I have prepared one depreciation study that combines Oncor and Oncor NTU assets. I am recommending one set of combined depreciation and amortization rates to be applied to both companies. Since Oncor's acquisition, Oncor NTU's transmission facilities have been operated and maintained, and new assets have been constructed and accounted for, consistent with the same business practices currently utilized by Oncor.

Q. WILL ONCOR AND ONCOR NTU BE SEPARATE BUSINESS ENTITIES FOR FINANCIAL REPORTING AND TAX PURPOSES?

A. Yes. As agreed and ordered by the Commission in Docket No. 48929, each entity will maintain separate books and records for external reporting and tax purposes. The rate filing package will reflect a single consolidated Company (including legacy Oncor and Oncor NTU), with functionalization of electric utility plant in service as specified by Commission rules. Functionalization of the consolidated Company's electric utility plant and the corresponding depreciation reserve accounts are discussed in the direct testimony of Company witness Mr. W. Alan Ledbetter. I functionalized accumulated depreciation and amortization amounts as well as proposed depreciation and amortization amounts for rate making based on functionalization plant amounts provided to me.

Q. WHAT IS THE AMOUNT OF ANNUAL DEPRECIATION EXPENSE THAT YOU ARE RECOMMENDING IN THIS PROCEEDING?

A. Based on the Company's depreciable plant in service at December 31, 2021, I recommend an annual depreciation expense for the combined utility plant assets of Oncor and Oncor NTU of approximately $900.9 million dollars. This is an increase of $34.1 million over the annualized depreciation expense calculated on year-end 2021 investment using the current depreciation rates, which were approved approximately four and a half years ago for Oncor in Docket No. 46957 and six and a half years ago in Sharyland's Docket No. 41474. For purposes of my testimony, I will refer to the combined costs of utility plant assets and the depreciation expense for Oncor and Oncor NTU as those of "Oncor."

Q. WHAT ARE THE PRIMARY FACTORS THAT HAVE INFLUENCED THE PROPOSED CHANGES IN THE COMPANY'S DEPRECIATION RATES?

A. There are two key factors that are driving the change in depreciation rates. First, the lives of assets contained within certain utility plant accounts have changed from the last depreciation study, with many of the asset lives being longer than previously approved. This has, therefore, necessitated a change in the lives and corresponding depreciation rate for the account, resulting in decreased depreciation expense. Second, the underlying cost of removing transmission and distribution assets has changed since the current net salvage rates (*i.e.,* rates reflecting removal costs less salvage proceeds) were established. In certain accounts, this has resulted in the Company incurring removal costs for retiring assets that have not been provided for in depreciation rates. These under-recovered amounts require that additional accruals be provided for in net salvage rates, which results in increased depreciation expense. This is somewhat offset by the experienced net salvage moving less negative in certain other accounts.

Q. DOES THE DEPRECIATION STUDY YOU SPONSOR IN THIS CASE REFLECT THE MOST CURRENT DATA AVAILABLE FOR ONCOR ASSETS?

A. Yes. In preparing this study, I have updated the data, analysis, and the resulting depreciation rates reflected in the depreciation study that I previously performed for Oncor assets through December 31, 2016, to reflect historical data through test-year-end December 31, 2021.

Q. HAVE YOU PREPARED ANY EXHIBITS IN CONNECTION WITH YOUR TESTIMONY?

A. Yes. I have prepared or supervised the preparation of the exhibits listed in my table of contents.

Q. WHAT COST-OF-SERVICE SCHEDULES DO YOU SPONSOR IN ONCOR'S RATE FILING PACKAGE ("RFP")?

A. I sponsor Schedule B-5 and co-sponsor Schedule E-1.

Q. HAVE YOUR TESTIMONY, YOUR EXHIBITS, AND THE RFP SCHEDULES THAT YOU SPONSOR BEEN PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes. My testimony, exhibits, and workpapers and the schedules that I sponsor or co-sponsor were prepared by me or under my direct supervision and are true and correct to the best of my knowledge and belief.

III. DEPRECIATION POLICY

Q. WHAT OBJECTIVE SHOULD THE COMMISSION STRIVE TO ACHIEVE IN SETTING DEPRECIATION RATES?

A. The objective of computing depreciation is to determine and include depreciation expense in customer rates and to ensure that, prospectively, all customers benefiting from the use of the Company's assets pay their pro rata share of the investment, including the future costs to remove and dispose of these assets at the end of their useful life. Customers pay their pro-rata share through the allocation of the cost of the depreciable assets over their useful life. Depreciation is recognized by charging a portion of the consumption of the assets to each accounting period through the application of Commission-approved depreciation rates.

Q. IS THIS OBJECTIVE CONSISTENT WITH COMMISSION RULES AND HISTORICAL PRACTICE?

A. Yes. As required by 16 Tex. Admin. Code ("TAC") § 25.231(b)(1)(B) and the Commission's prior rate decisions, the Commission has a long-standing practice of establishing depreciation rates using the straight-line depreciation method based on the actual historic data of the utility. The straight-line method of depreciation operates by collecting a pro rata share of the cost of the investment, including removal cost, net of salvage, from all customers that use the asset over its useful life.

Q. WHAT IS THE BEST EVIDENCE THAT THE COMMISSION CAN RELY ON IN ORDER TO ENSURE THAT THE COST OF ASSETS ARE RATABLY RECOVERED OVER THE SERVICE LIVES?

A. The best evidence is based on the actual experience of the specific group of assets being analyzed, as taken from the actual books and records of the Company to the fullest extent possible. Adjustments to the Company's asset cost recovery may at times be necessary when the actual historical experience of the Company reflects changing lives or net salvage factors. Changes can be driven by, among other things, changes in the Company's construction, operating or maintenance practices, as conveyed to me through interviews with Company personnel. This evidence is found in my depreciation study, which is based on the Company's plant investment in service at December 31, 2021.

IV. ONCOR DEPRECIATION STUDY

A. SUMMARY OF THE DEPRECIATION STUDY RESULTS

Q. HAVE YOU PREPARED A DEPRECIATION STUDY FOR ONCOR?

A. Yes. In connection with the filing of this case, I undertook a comprehensive analysis of annual depreciation for Oncor that is based on the Company's depreciable plant in service at December 31, 2021. The depreciation study analyzed the property characteristics of the Company's transmission plant, distribution plant, and general plant and proposes depreciation rates for these assets. Additionally, I have calculated the appropriate depreciation rates to be applied to the Company's investments in Federal Energy Regulatory Commission ("FERC") Account 303, Intangible Plant assets, based on an analysis of computer business system service lives that were provided to me by Company witness Ms. Malia A. Hodges and by also taking into consideration those amounts that have previously been recovered for these systems in the Company's rates. The study, along with the calculation of the rates for Intangible Plant assets, is attached to my direct testimony as Exhibit DAW–2.

Q. ARE ALL OF ONCOR'S ASSETS THAT ARE INCLUDED IN ACCOUNT 101, ELECTRIC PLANT IN SERVICE, INCLUDED IN THE DEPRECIATION STUDY?

A. No. Assets included in Account 101 that are classified as non-depreciable land are not included in the depreciation study. I have also excluded any asset that is not included in rate base, such as the Company's investment in aircraft. Additionally, as discussed in more detail in the testimony of Mr. Ledbetter, I have excluded certain transmission assets that are included in the proposed transfer of facilities to Lubbock Power and Light in Docket No. 52726. I have also excluded $3.2 million of plant in Account 362 consisting of mobile generators that are recovered through a capital lease. Finally, as discussed in the direct testimony of Company witness Mr. Ledbetter, there is a balance of approximately $23.5 million in unamortized FERC *A114 Electric Plant Acquisition Adjustments* related to Oncor NTU. I have provided Mr. Ledbetter with the estimated remaining useful life of these assets as of the 2021 test-year-end in order to determine the annual amortization expense associated with this investment in Oncor NTU FERC A114. I have incorporated my recommended depreciation expense for all other investment in the total requested depreciation and amortization expense shown in both RFP Schedule E-1 and the depreciation study, Exhibit DAW-2, Appendix B.

Q. HAVE THE RESULTS OF YOUR DEPRECIATION STUDY BEEN INCLUDED IN THE COMPANY'S TEST-YEAR-END DECEMBER 31, 2021 COST-OF-SERVICE REQUEST?

A. Yes. The results of my depreciation study have been applied to the plant balances as of December 31, 2021, and have been included in the Company's requested cost of service.

Q. WHEN DID THE LAST CHANGE IN THE COMPANY'S DEPRECIATION RATES OCCUR?

A. The last change in the Company's intangible, transmission, distribution, and general plant depreciation rates occurred in November 2017 with the final Order in Docket No. 46957. Those rates were established using (in part) a study I conducted based on plant in service at December 31, 2016, and were the result of a Commission-approved settlement agreement. As I previously mentioned, the depreciation rates utilized by Oncor NTU were approved in Sharyland's Docket No. 41474.

Q. ARE THE DEPRECIATION RATES IN THE SETTLEMENT AGREEMENT FROM DOCKET NO. 46957 INDICATIVE OF YOUR RECOMMENDATIONS IN THIS CASE?

A. No. In Docket No. 46957, Oncor agreed to depreciation rates that resulted in a depreciation expense that was $125 million lower than the amount originally requested in that case. My study in this proceeding is a thorough review of Oncor's assets and does not incorporate positions and negotiations that were necessary to obtain a settlement agreement in Docket No. 46957.

Q. DOES YOUR CURRENT DEPRECIATION STUDY ESTABLISH THAT THE COMPANY'S TRANSMISSION AND DISTRIBUTION ASSETS ARE CONTINUING TO EXPERIENCE LONGER SERVICE LIVES AND CHANGING NEGATIVE NET SALVAGE LEVELS?

A. Yes. A trend in longer service lives and changing net salvage amounts for the Company's transmission and distribution property has continued to occur since the 2016 depreciation study was completed. The Company's proposed depreciation rates in this case reflect this experience.

Q. ARE YOU PROPOSING A CHANGE IN DEPRECIATION EXPENSE FOR TRANSMISSION PLANT BASED ON YOUR RECENT STUDY?

A. Yes. Based on my most recent depreciation study, the annual depreciation expense for Transmission assets, including transmission substations, should be decreased by approximately $50.0 million per year. This reflects the difference between the current rates and the proposed rates as applied to test-year-end December 31, 2021 investment for Transmission, as shown in the Oncor Depreciation Study in Exhibit DAW-2, Appendix B.

Q. WHAT DEPRECIATION RATES FOR TRANSMISSION ARE YOU PROPOSING, AND HOW DO THEY COMPARE WITH THE CURRENT RATES?

A. The functional composite depreciation rate requested in this case for transmission is 2.51 percent compared to the current functional depreciation rate of 2.89 percent. These rates are shown in the Oncor Depreciation Study in Exhibit DAW-2, Appendix B. Detailed calculations of these rates are found in Exhibit DAW–2, Appendix A.

Q. ARE YOU PROPOSING A CHANGE IN DEPRECIATION EXPENSE FOR DISTRIBUTION SUBSTATIONS BASED ON YOUR CURRENT STUDY?

A. Yes. Based on the current depreciation study, the annual depreciation expense for distribution substations should be increased by approximately $7.7 million per year. This amount was determined by comparing the depreciation expense difference between the current rates and the proposed rates as applied to test-year-end December 31, 2021 investment for distribution substations, as shown in the Oncor Depreciation Study in Exhibit DAW-2, Appendix B.

Q. WHAT DEPRECIATION RATES FOR DISTRIBUTION SUBSTATIONS ARE YOU PROPOSING, AND HOW DO THEY COMPARE WITH THE CURRENT RATES?

A. The functional composite depreciation rate requested in this case for distribution substations is 2.09 percent compared to the current functional depreciation rate of 1.80 percent. These rates are shown in the Oncor Depreciation Study in Exhibit DAW-2, Appendix B. Detailed calculations of these rates are found in Exhibit DAW–2, Appendix A.

Q. ARE YOU PROPOSING A CHANGE IN DEPRECIATION EXPENSE FOR DISTRIBUTION PLANT EXCLUDING SUBSTATIONS BASED ON YOUR CURRENT STUDY?

A. Yes. Based on the current depreciation study, the annual depreciation expense for distribution assets other than substations should be increased by approximately $27.5 million per year. This reflects the difference between the current rates and the proposed rates as applied to test-year-end December 31, 2021 investment for distribution, as shown in the Oncor Depreciation Study in Exhibit DAW-2, Appendix B.

Q. WHAT DEPRECIATION RATES FOR DISTRIBUTION EXCLUDING SUBSTATIONS ARE YOU PROPOSING, AND HOW DO THEY COMPARE WITH THE CURRENT RATES?

A. The functional composite depreciation rate requested in this case for distribution excluding substations is 2.89 percent as compared to the current functional depreciation rate of 2.68 percent. These rates are shown in the Oncor Depreciation Study in Exhibit DAW-2, Appendix B. Detailed calculations of these rates are found in Exhibit DAW–2, Appendix A.

Q. ARE YOU PROPOSING A CHANGE IN DEPRECIATION EXPENSE FOR GENERAL PLANT BASED ON YOUR MOST RECENT STUDY?

A. Yes. Based on my most recent study, the annual depreciation and vintage group amortization expense for general plant assets should be increased by approximately $39.9 million per year. This amount was determined by comparing the difference in depreciation expense between the current rates and the proposed rates as applied to test-year-end December 31, 2021 investment for general plant as shown in the Oncor Depreciation Study in Exhibit DAW-2, Appendix B.

Q. WHAT DEPRECIATION RATES FOR GENERAL PLANT ARE YOU PROPOSING AND HOW DO THEY COMPARE WITH THE CURRENT RATES?

A. Oncor adopted the vintaged group amortization methodology consistent with FERC Accounting Release Number 15 ("AR-15") as of January 1, 2008. I calculated depreciation expense for a number of General Plant asset groups using this method. The General Plant accounts where Oncor adopted AR-15 amortization included Accounts 391 through 398 (excluding a portion of Account 397). AR-15 provides for the amortization of general plant over the same life as recommended in this study (with a separate amortization to allocate deficit or excess reserve as necessary). At the end of the amortizable life, all property is then retired from the books. Implementation of this approach did not affect the annual depreciation expense accrued by Oncor and provides for the retirement of assets and the simplification of accounting for certain general plant property. The Commission approved this approach in Docket No. 35717, Oncor's 2008 base-rate case, and Oncor has continued the use of AR-15 methodology since that case. Accounts 389 (Land Rights), 390 (Buildings and Structures) and portions of Account 397 (Communication Equipment) use the traditional (*i.e.*, non-AR-15 methodology) depreciation methodology and calculations. The effective proposed functional rate for general plant including AR15 assets is 7.09 percent as compared to the currently approved 3.89 percent. The study's workpapers include the amortization schedules for this approach. These rates are shown in the Oncor Depreciation Study in Exhibit DAW-2, Appendix B. Detailed calculations of this rate are found in Exhibit DAW-2, Appendix A.

B. METHODOLOGICAL OVERVIEW OF DEPRECIATION STUDY

Q. WHAT DEFINITION OF DEPRECIATION HAVE YOU USED FOR PURPOSES OF CONDUCTING YOUR DEPRECIATION STUDY AND PREPARING YOUR DIRECT TESTIMONY?

A. The term "depreciation," as used herein, is considered in the accounting sense; that is, a system of accounting that distributes the cost of assets, less net salvage (if any), over the estimated useful life of the assets in a systematic and rational manner. It is a process of allocation, not valuation. Depreciation expense is systematically allocated to accounting periods over the life of the properties. The amount allocated to any one accounting period does not necessarily represent the loss or decrease in value that will occur during that particular period. Thus, depreciation is considered an expense or cost, rather than a loss or decrease in value. The Company accrues depreciation based on the original cost of all property included in each depreciable plant account. On retirement, the full cost of depreciable property, less the net salvage amount, if any, is charged to the depreciation reserve.

Q. PLEASE DESCRIBE YOUR DEPRECIATION STUDY APPROACH.

A. I conducted the depreciation study in four phases, as shown in my Exhibit DAW-2. The four phases are: Data Collection; Analysis; Evaluation; and Calculation. I began each of the studies by collecting the historical data to be used in the analysis. After the data had been assembled, I performed analyses to determine the life and net salvage percentage for the different property groups being studied. As part of this process, I conferred with field personnel, engineers, and managers responsible for the installation, operation, and removal of the assets to gain their input into the operation, maintenance, and salvage of the assets. The information obtained from field personnel, engineers, and managerial personnel, combined with the study results, is then evaluated to determine how the results of the historical asset activity analysis, in conjunction with the Company's expected future plans should be applied. As the former manager of the property accounting organization for the Company, I have personal knowledge of the Company's Continuing Property Records system and the fixed asset accounting procedures used by the Company. I am, therefore, uniquely positioned to gather, analyze, and evaluate the data used in the Company's depreciation studies. Using all of these resources, I then calculate the depreciation rate for each function.

Q. WHAT PROPERTY IS INCLUDED IN THE DEPRECIATION STUDY?

A. There are four FERC functional classifications of property included in this study: intangible; transmission; distribution; and general property. Intangible property consists of software used for various purposes in the course of business. The transmission plant function includes high-voltage structures, substations, and transmission lines operating at 60 KV or greater that are used in the transmission of energy to the distribution system. The distribution plant function includes easements and Right-of-Ways, substation structures and equipment, transformers, meters, service conductors, conduit, distribution lines, guard lights, and street lighting used in the distribution and end use of energy on the distribution system that operates at less than 60 KV. The general plant function includes facilities associated with the overall operation of the business such as office equipment and computers rather than with a specific transmission or distribution classification. Some asset categories that were previously depreciated in larger asset group accounts have been segregated into different sub-accounts for this study. The asset sub-accounts relate to Direct Current ("DC") Ties, Static VAR Compensators ("SVC"), and Static Synchronous Compensator ("Statcom") equipment, separation of computer equipment from office fixtures and furnishings, and separation of small tools from other large tool, shop, and garage equipment.

Q. WHAT DEPRECIATION METHODOLOGY DID YOU USE FOR YOUR STUDY?

A. I have used the straight-line, Average Life Group, remaining-life depreciation system to calculate annual and accrued depreciation in the study. The Commission has approved the use of this methodology in prior rate cases because it is reasonable and widely accepted. In addition, the Company wanted the depreciation study for this proceeding to employ the same accepted methodology that has been used in past depreciation studies for purposes of consistency.

C. SERVICE LIVES

Q. WHAT IS THE SIGNIFICANCE OF AN ASSET'S USEFUL LIFE IN YOUR DEPRECIATION STUDY?

A. An asset's useful life was used to determine the remaining life over which the remaining cost (original cost plus or minus net salvage, minus accumulated depreciation) can be allocated to normalize the asset's cost and spread it ratably over future periods.

Q. HOW DID YOU DETERMINE THE AVERAGE SERVICE LIFE FOR EACH ACCOUNT?

A. The establishment of an appropriate average service life for each account within a functional group was determined by using one of two widely accepted depreciation analyses: Actuarial analysis or Simulated Plant Record ("SPR") methods. Because vintaged data used in actuarial analysis contains more information than unaged data in SPR analysis, actuarial analysis is the preferred analysis tool for accounts when there are both a sufficient number of transaction years available to model an account and sufficient transactions within those years to be predictive in modeling the historical life parameters.

Q. WHAT ACCOUNTS USED ACTUARIAL ANALYSIS FOR LIFE SELECTIONS?

A. The accounts using actuarial analysis as the primary life modeling tool were: Accounts 352-355, 361, and 390 (where there were 32 years of actuarial data – from 1990-2021). I also modeled the depreciation portion of Account

397 with actuarial analysis since transaction data was amiable from 2000 through 2021. I excluded assets that are subject to amortization under AR-15 from life analysis. Accounts 356, 362, and many of the distribution overhead and underground line accounts 364-369 and, 371-373 were modeled with SPR analysis. In the case of distribution accounts (Accounts 364 through 369 and 371-373), which generally had only 23 years of actuarial data, the number of transaction years was not sufficient in many cases to conduct a fully predictive actuarial analysis. For this reason, I placed more weight on the SPR analysis for these accounts. Graphs and tables supporting the actuarial analysis or SPR and the chosen Iowa Curves used to determine the average service lives for analyzed accounts are found in the Oncor Depreciation Study (Exhibit DAW-2) and the workpapers filed with Exhibit DAW-2. Judgment was used to factor any differences in the expected future life characteristics of the assets into the selection of lives. I would stress that the objective of life selection is to estimate the future life characteristics of assets and to not simply measure the historical life characteristics and mechanically project them into the future. More information can be found in the life analysis section of the Oncor Depreciation Study contained in Exhibit DAW-2.

1. Service Life Characteristics for Transmission and Distribution Substation Plant

Q. DOES YOUR DEPRECIATION STUDY REFLECT ANY CHANGES IN THE USEFUL LIVES OF THE TRANSMISSION FUNCTION ASSETS FROM THE LIVES EMBEDDED IN THE CURRENT DEPRECIATION RATES?

A. Yes. As shown in Appendix C of Exhibit DAW-2, 6 of the12 accounts have longer lives ranging from an additional 7 years for Accounts 352 (Structures and Improvements) and 12 years for Account 354 (Towers and Fixtures) to an additional 4 years for Account 353 (Station Equipment). The lives for one account remained unchanged from the prior study, and the four accounts related to DC Ties and SVC assets have decreases in life.

Q. WHAT IS THE CAUSE OF THE GENERAL INCREASE IN LIVES FOR THE TRANSMISSION FUNCTIONAL GROUP?

A. Generally, transmission infrastructure across the country is experiencing longer service lives. The lengthening of service lives for transmission assets can be attributed to the changing mix of assets within the accounts, practices that extend the life of assets, and more robust maintenance practices. There are other factors that somewhat moderate the life increases such as a higher level of electronics on the system (which have shorter lives than the traditional long-lived assets in the accounts).

2. Service Life Characteristics for Distribution Plant

Q. DOES YOUR DEPRECIATION STUDY REFLECT ANY CHANGES IN THE USEFUL LIVES OF THE DISTRIBUTION FUNCTION ASSETS FROM THE LIVES EMBEDDED IN THE CURRENT DEPRECIATION RATES?

A. Yes. As shown in Appendix C of Exhibit DAW-2, 8 out of the 13 distribution accounts have longer lives ranging from an additional two years for Account 362 – (Station Equipment) to an additional 13 years for Account 361 – (Structures and Improvements). No accounts had a decrease in life. Accounts 360 – (Land Rights), 370 – (Meters), 371 – (Installation on Customer Premises), and 373 - (Street Lighting) are proposed to retain the existing life.

Q. WHAT IS THE CAUSE OF THE GENERAL INCREASE IN LIVES FOR THE DISTRIBUTION FUNCTIONAL GROUP?

A. The Company has successfully implemented aggressive preventive maintenance programs that have increased the useful lives of distribution function assets. These preventive maintenance programs include cable cure for underground conductors, pole treatments and reinforcement, and a newer standard for cross-linked polyethylene ("XLP") conductors. These programs have extended the lives of distribution assets.

3. Service Life Characteristics for General Plant

Q. DOES YOUR DEPRECIATION STUDY REFLECT ANY CHANGES IN THE USEFUL LIVES OF THE GENERAL PLANT FUNCTION ASSETS FROM THE LIVES EMBEDDED IN THE CURRENT DEPRECIATION RATES?

A. Yes. As shown in Appendix C of Exhibit DAW-2, 4 of the 16 general plant accounts have longer lives ranging from an additional two years for Account 390 – (Structures and Improvements) to an additional five years for Account 389 – (Land and Land Rights) and 397 (Communication Equipment – non-AR-15 methodology). For those general plant accounts that are subject to AR-15 amortization, this study recommends separating the assets in Account 391 (Office Furniture and Equipment) into two sub-accounts: (i) Computer Equipment; and (ii) Other Office Furniture and Equipment. Account 392 (Transportation Equipment) is proposed to be segregated into three separate sub-accounts: Light Trucks; Heavy Trucks; and Trailers. Additionally, Account 394 (Tools, Shop and Garage Equipment) is proposed to be separated into two sub-accounts: small tools and large tools. The separation of accounts 391, 392, and 394 into the proposed sub-accounts allows for these assets to be grouped and amortized using the AR-15 methodology more closely to their expected useful lives. Since these accounts are being recovered through general plant amortization, there is an automatic retirement process and, therefore, it is not possible to perform actuarial analysis to estimate the lives of those assets. As with other new asset groups, I have interviewed Company subject matter experts who work with the assets, and I used my professional judgment and experience to estimate the lives for these categories of plant. As such, Accounts 391, 392, and 394 collectively show an overall reduction in life.

Q. WHAT HAS CAUSED THE CHANGE IN LIVES FOR GENERAL PLANT ASSETS?

A. The largest increase in service life for general plant is in Account 390 – (Structures and Improvements). The increase in Account 390 is based on the expectation that the buildings and structures in this account are lasting longer than projected in 2016. The decreases in lives for Accounts 391 and 394 are based on a review of the assets in these accounts that have resulted in the proposal for new sub-accounts that I previously discussed.

4. Service Life of Intangible Assets

Q. ARE YOU PROPOSING A CHANGE IN DEPRECIATION EXPENSE FOR INTANGIBLE ASSETS BASED ON THE MOST RECENT STUDY?

A. Yes. Based on the most recent depreciation study, the annual depreciation expense for Intangible assets recorded in Account 303 should be increased by approximately $21.6 million per year. This amount was determined by comparing the depreciation expense difference between the current rates and the proposed rates as applied to test-year-end December 31, 2021 investment for Intangible assets, as shown in the Oncor Depreciation Study in Exhibit DAW-2, Appendix B.

Q, WHAT DEPRECIABLE LIVES ARE CURRENTLY USED BY ONCOR FOR DEPRECIATION OF INTANGIBLE ASSET INVESTMENT THAT IS RECORDED IN FERC ACCOUNT 303?

A. Oncor's intangible assets are currently classified into three groups – assets with five-year, eight-year, and 15-year estimated service lives. The Company has developed a set of comprehensive criteria for determining the service life for each of its software systems. While I have not personally made the determination of each system's expected useful life, I have reviewed the Company's criteria for assigning lives to its various computer software assets and find them to be reasonable and consistent with computer business system lives used by other companies within the electric utility industry. A listing of each of Oncor's computer business systems recorded in Account 303 and their estimated service lives are contained in my workpapers.

Q. ARE THESE THE SAME SERVICE LIFE GROUPS THAT WERE APPROVED IN THE COMPANY'S LAST BASE-RATE CASE?

A. Yes, with one exception. The Company has proposed the addition of a three-year service life group, which corresponds to the contractual licensing period for certain software applications. The five-year, eight-year, and 15-year service life groups are the same ones that were previously requested by Oncor and approved in the Company's last base-rate case, Docket No. 46957. In that docket, I calculated the depreciation rates for each of the Company's service life groups and have used the same methodology from Docket No. 46957 to calculate the service life group rates for this case

Q. PLEASE DESCRIBE WHAT IS MEANT BY CALCULATING DEPRECIATION RATES USING THE GROUP CONCEPT FOR INTANGIBLE ASSETS.

A. Calculating depreciation rates for intangible assets using the group concept allows for the accounting and ratemaking treatment to "mirror" the same treatment that is used for tangible assets, such as that used for poles and conductors. Under the group concept, depreciation expense is calculated by considering the remaining lives of the assets and the amount of accumulated depreciation that has been allocated to the group. Depreciation is then calculated and systematically allocated to accounting periods over the life of the properties. The amount allocated to each accounting period does not necessarily represent the loss or decrease in value that will occur during that particular period. The Company accrues depreciation on the basis of the original cost of all depreciable property included in each estimated service life group. Upon retirement of an asset within the group, the original cost of the asset is removed from Electric Plant in Service FERC Account 101 and is charged to the depreciation reserve FERC Account 108 as opposed to recording a gain or loss on the income statement.

Q. IS ONCOR PROPOSING TO MAKE ANY CHANGES TO ITS ESTIMATED SERVICE LIFE GROUPS IN THIS CASE?

A. Yes. As I previously mentioned, Oncor proposes a new three-year life category be approved in addition to approval and continued use of the existing five-year, eight-year, and 15-year service life groups that were established in Docket No. 46957. This new three-year life category is needed for depreciation of Oncor's hosted software applications having three-year fixed-term agreements. Hosted software applications are those systems that are either owned by a third party and licensed by Oncor for a fixed period of time or a software application owned by Oncor that was developed by a third party and is hosted by the third party for a fixed period of time. Presently, third parties only support three- or five-year fixed-term agreements, therefore necessitating the addition of a new three-year service life category. For this filing, the Company requests the amount of approximately $408 thousand be included in the proposed three-year life group.

Q. HAS ONCOR ADDED OR REPLACED ANY SOFTWARE APPLICATIONS OR SYSTEMS SINCE ITS LAST BASE-RATE CASE THAT HAVE BEEN ADDED TO THESE GROUPS?

A. Yes. Oncor has added a number of new software applications or systems. Please refer to Company witnesses Mr. Joel S. Austin and Ms. Hodges' direct testimony for a discussion of these investments that have been added or replaced since the Company's last base-rate case. Each new software application or system placed into service during this time period has been assigned either a three-year, five-year, eight-year, or 15-year estimated service life. None of these software assets were projected to have a life in excess of 15 years.

Q. ARE YOU PROPOSING A CHANGE IN DEPRECIATION EXPENSE FOR INTANGIBLE ASSETS BASED ON THE NEW GROUP DEPRECIATION RATES THAT YOU HAVE CALCULATED?

A. Yes. Based on my calculation of new group depreciation rates, the annual depreciation expense for Intangible assets should be increased by approximately $21.6 million per year. This amount was determined by comparing the depreciation expense difference between the current rates and the proposed rates as applied to test-year-end December 31, 2021 investment for intangible assets, as shown in the Oncor Depreciation Study in Exhibit DAW-2, Appendix B.

Q. HAVE THERE BEEN ANY SIGNIFICANT CHANGES TO SOFTWARE ASSET SERVICE LIVES FOR SOFTWARE ADDED SINCE THE COMPANY'S LAST BASE-RATE CASE?

A. No. The systems that have been placed into service have incorporated the same life groups previously adopted in the Company's last base-rate case. I would note, however, that for the limited purpose of settling prior distribution cost recovery factor ("DCRF") cases, the Company agreed to temporarily recognize longer lives for two major intangible systems placed in service since Oncor's last base-rate case. Specifically, the Company's Customer Care and Billing ("CC&B") (placed in service in November 2017) and Advanced Enterprise Geographic Information System ("AEGIS") (placed in service in 2020) projects associated with these systems are included in the 15-year service life intangible asset group in this filing, In order to reflect the actual expected lives of CC&B and AEGIS. In my opinion, the 15-year lives recommended by the Company is more in line with the lives used by other utilities across the nation, regardless of the fact that Oncor agreed to a 25-year amortization period for these assets for settlement purposes in one or more prior DCRF cases.

Q. IN YOUR OPINION, WHAT FACTORS SUPPORT A 15-YEAR LIFE FOR THESE ASSETS?

A. Based on my interviews and discussions with Company management and Information Technology subject matter experts, the CC&B project included the replacement of a mainframe-based customer information and billing system that was more than 30 years old. The life of the prior Oncor system, however, has little relevance to today's technology and systems. In light of today's rapid pace of technological advancement and the evolving needs of customer information systems and graphical management tools, a 25-year life is outside industry norms. Oncor periodically upgrades the software implemented as part of the CC&B project, and these upgrades will eventually rewrite and replace existing computer code. When Oncor ascertains that the original code has been fully replaced through upgrades, the original software asset investment will be retired. Based on the upgrade schedule, even 15 years is possibly longer than the original vintage year 2017 may last. Therefore, it is reasonable to expect that the CC&B investment placed in service in 2017 will have a significantly shorter useful life than the previous investment it replaced, and extending the life of the asset beyond 15 years is simply not rational.

Similarly, a 25-year amortization period for the AEGIS investment does not reasonably align with the actual expected life of the asset. On the contrary, the proposed 15-year life is consistent with the expected useful life for large computer business systems that I have observed across electric and gas utility industries in the state of Texas and across the United States, as well as being consistent with Oncor's own accounting processes.

5. Service Life New Asset Groups

Q. ARE THERE ANY NEW CATEGORIES OF TANGIBLE ASSETS THAT ONCOR OWNS THAT WERE NOT PART OF THE COMPANY'S LAST DEPRECIATION STUDY IN DOCKET NO. 46957?

A. Yes. Since the last depreciation study, Oncor has added new asset types and has requested that I examine the asset mix in various accounts and determine if any sub-groupings would be appropriate for these new-assets. In the Transmission function, I reviewed information for DC Ties, Static Var Compensators (SVC), and StatCom Assets. I recommend these assets be separated into new, distinct subaccounts. Because these assets have only been in service a short time, there is insufficient historical retirement data available to model or predict the retirement patterns for those assets. Thus, I have interviewed Company experts who operate the assets and have used my professional judgment and experience to estimate the lives for those categories of plant.

D. NET SALVAGE RATES

Q. WHAT IS THE SIGNIFICANCE OF NET SALVAGE RATES FOR ONCOR PLANT ASSETS?

A. In general, net salvage values are the amounts received for retired property (salvage) less any costs incurred to sell or remove the property (removal). When salvage exceeds removal (positive net salvage), the net salvage reduces the amount to be depreciated over time. When removal exceeds salvage (negative net salvage), the negative net salvage increases the amount to be depreciated. For transmission and distribution plant in this depreciation study, the net salvage percentages were calculated for each property account using Company data from 1995 or 1998 through 2021. For general plant accounts, the net salvage percentages were calculated by property account using Company data from 1995 through 2021.

Q. HOW DID YOU DETERMINE THE NET SALVAGE RATES THAT YOU UTILIZED IN YOUR STUDY?

A. I examined the experience realized by the Company by observing the average net salvage for various bands (or combinations) of years. Using averages (such as the five-year and 10-year average bands) allows the smoothing of the timing differences between when retirements, removal cost, and salvage are booked and smooths the natural variations between years. By looking at successive average bands ("rolling bands"), an experienced analyst can see trends in the data that would signal the future net salvage in the account. This examination, in combination with the feedback of Company personnel related to any changes in operations or maintenance that would affect the future net salvage of the Company, allowed the selection of the best estimate of future net salvage for each account.

Q. IS THIS A REASONABLE METHOD FOR DETERMINING NET SALVAGE RATES?

A. Yes, it is. This methodology is commonly employed throughout the industry and is the method recommended in authoritative texts.

Q. DOES YOUR DEPRECIATION STUDY REFLECT ANY CHANGE IN THE NET SALVAGE VALUES OF THE TRANSMISSION AND DISTRIBUTION PROPERTY FROM THE EXISTING NET SALVAGE RATES EMBEDDED IN THE CURRENT DEPRECIATION RATES?

A. Yes. The net salvage values for both transmission and distribution property have experienced a significant change since the Commission established the current net salvage rates for these assets more than four and a half years ago in Oncor's Docket No. 46957 and six and a half years ago in Sharyland's Docket No. 41474. The net salvage values used in the calculation of the transmission and distribution depreciation rates are listed in Exhibit DAW-2, Appendix E.

1. Net Salvage Rates for Transmission and Distribution Substation Property

Q. WHAT HAS CAUSED THE SIGNIFICANT CHANGE IN NET SALVAGE RATES FOR TRANSMISSION AND DISTRIBUTION SUBSTATION PROPERTY?

A. There are two primary reasons for the significant change in net salvage rates for transmission and distribution substation property. The first reason has to do with the Company's historical removal cost experience having changed from what is reflected in the current depreciation rates. A second reason is a change in capital investment deployed since Docket No. 46957.

Q. HAVE TRANSMISSION AND DISTRIBUTION SUBSTATION REMOVAL COSTS CHANGED SINCE THE SETTLEMENT AGREEMENT WAS ADOPTED IN DOCKET NO. 46957?

A. Yes, as shown in the net salvage analysis in Exhibit DAW-2, removal costs for almost every plant account have changed since the last depreciation study that I performed for Oncor.

Q. WHAT ACTIVITIES WERE TAKING PLACE AT THE TIME OF THE FINAL ORDER IN DOCKET NO. 46957?

A. Between the years 2003 through 2008, the Company began a program to mitigate congestion on transmission lines in the DFW area and replace assets. Congestion mitigation projects required the reconductoring and rebuilding of towers and poles. Those projects have moderated and continued at a reduced level since Docket No. 35717. Since Docket No. 46957, Oncor has focused on replacement of its aging infrastructures, which has increased net salvage costs from 2008-2016 when the Company deployed capital to smart grid projects and competitive renewable energy zone projects. Since 2017, capital spending has resumed a normal balance between new infrastructure (greenfield) and infrastructure replacement (brownfield), more retirements are expected to occur in both the transmission and distribution accounts.

Q. WHAT NET SALVAGE RATES ARE YOU RECOMMENDING FOR THE TRANSMISSION ASSETS?

A. The recommended net salvage rates for Transmission assets are shown in Exhibit DAW-2, Appendix C. Detailed computations by account are shown in Appendix E.

2. Net Salvage Rates for Distribution (Accounts 364-373) Property

Q. WHAT HAS CAUSED THE SIGNIFICANT CHANGE IN NET SALVAGE RATES FOR DISTRIBUTION PLANT?

A. The data related to the Company's actual experience in recent years demonstrates that the Company has continued to experience significant increases in the removal cost incurred to retire assets since the existing depreciation rates were established based on a 2016 Depreciation Study. Increasing costs of construction in metropolitan areas and work required by distribution system upgrades have both contributed to increasing distribution removal costs. Additionally, in order to reach a settlement in Docket No. 46957, the Company agreed to net salvage parameters that were lower than its historic experience at that time. More detail can be found in the Salvage Analysis section of my Depreciation Study found in Exhibit DAW-2.

3. Net Salvage Rates for General Property

Q. WHAT NET SALVAGE VALUE WAS USED IN THE CALCULATION OF THE GENERAL PLANT DEPRECIATION RATES?

A. Net salvage rates for general plant accounts are listed in Exhibit DAW-2, Appendix C.

Q. HAVE THE NET SALVAGE RATES CHANGED FOR GENERAL PLANT PROPERTY?

A. The net salvage rates for general plant have changed very little. General plant net salvage was set at 0 percent for the general plant function in Docket No. 46957 and at a positive 10 percent for Transportation Equipment and Power Operated Equipment. This study recommends moving to a positive 20 percent for both Transportation Equipment, Account 392, and Power Operated Equipment, Account 396, and a negative five percent for general plant Structures and Improvements, Account 390, and a negative two percent for Account 397, Communication Equipment - non-AR-15 property. All other general plant accounts retain the same zero percent net salvage approved in Docket No. 46957.

4. Net Salvage Rates for New Categories of Assets

Q. WHAT NET SALVAGE VALUE WAS USED IN THE CALCULATION OF THE NEW CATEGORIES OF ASSETS

A. Net salvage rates for new asset groups are listed in Exhibit DAW-2, Appendix C.

Q. HOW DID YOU DETERMINE NET SALVAGE RATES FOR NEW ASSET TYPES?

A. Where possible, I used my recommendations for similar assets with historical experience within the same function to estimate net salvage for these new asset groups (e.g., transmission station equipment as a surrogate for DC Tie and SVC equipment).

V. SUMMARY AND CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. The depreciation rates I propose in this case are an accurate estimate of Oncor's future life and salvage expectations and should be accepted. The proposed plant depreciation rate reflects the significant changes that have occurred in Oncor's depreciable and amortizable property since Docket No. 46957. As such, the depreciation expense that I recommend should be adopted. Finally, Oncor will continue to periodically review the depreciation rates for its property in an effort to ensure that all customers are charged for their appropriate share of the capital expended for their benefit.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

AFFIDAVIT

STATE OF TEXAS §
§
COUNTY OF DALLAS §

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

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

Dane A. Watson

Dane A. Watson

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

NOTARY PUBLIC STATE OF TEXAS
TERI SMART
Notary Public, State of Texas
Comm. Expires 11-13-2024
Notary ID 514088-5

Teri Smart

Notary Public, State of Texas

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Oklahoma	Corporation Commission of Oklahoma	PUD 202100163	Empire District Electric Company	2022	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-21176	Consumers Gas	2021	Gas Depreciation Study
New Jersey	New Jersey Board of Public Utilities	GR21121254	Elizabethtown Natural Gas	2021	Gas Depreciation Study
Ontario Canada	Ontario Energy Board	EB-2021-0110	Hydro One	2021	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	TA116-118, TA115-97, TA160-37 and TA110-290	Fairbanks Water and Wastewater	2021	Water and Waste Water Depreciation Study
Colorado	Public Utilities Commission of Colorado	21AL-0317E	Public Service of Colorado	2021	Electric and Common Depreciation Study
Alaska	Regulatory Commission of Alaska	U-21-025	Golden Valley Electric Association	2021	Electric Depreciation Study
Wisconsin	Public Service Commission of Wisconsin	5-DU-103	WE Energies	2021	Electric and Gas Depreciation Study
Kentucky	Public Service Commission of Kentucky	2021-00214	Atmos Kentucky	2021	Gas Depreciation Study
Missouri	Missouri Public Service Commission	ER-2021-0312	Empire District Electric Company	2021	Electric Depreciation Study
Wisconsin	Public Service Commission of Wisconsin	4220-DU-111	Northern States Power Wisconsin	2021	Transmission, Distribution General and Common Depreciation Study
Louisiana	Louisiana Public Service Commission	U-35951	Atmos Energy	2021	Statewide Gas Depreciation Study
Minnesota	Minnesota Public Utilities Commission	E015-D-21-229	Allete Minnesota Power	2021	Intangible, Transmission, Distribution, and General Depreciation Study
Michigan	Michigan Public Service Commission	U-20849	Consumers Energy	2021	Electric and Common Depreciation Study
Texas	Texas Public Utility Commission	51802	Southwestern Public Service Company	2021	Electric Technical Update
MultiState	FERC	RP21-441-000	Florida Gas Transmission	2021	Gas Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
New Mexico	New Mexico Public Regulation Commission	20-00238-UT	Southwestern Public Service Company	2021	Electric Technical Update
Yukon Territory Canada	Yukon Energy Board	2021 General Rate Application	Yukon Energy	2020	Electric Depreciation Study
MultiState	FERC	ER21-709-000	American Transmission Company	2020	Electric Depreciation Study
Texas	Texas Public Utility Commission	51611	Sharyland Utilities	2020	Electric Depreciation Study
Texas	Texas Public Utility Commission	51536	Brownsville Public Utilities Board	2020	Electric Depreciation Study
New Jersey	New Jersey Board of Public Utilities	WR20110729	Suez Water New Jersey	2020	Water and Waste Water Depreciation Study
Idaho	Idaho Public Service Commission	SUZ-W-20-02	Suez Water Idaho	2020	Water Depreciation Study
Texas	Texas Public Utility Commission	50944	Monarch Utilities	2020	Water and Waste Water Depreciation Study
Michigan	Michigan Public Service Commission	U-20844	Consumers Energy/DTE Electric	2020	Ludington Pumped Storage Depreciation Study
Mexico	Comision Reguladora de Energia	G/352/TRA/2015 UH-250/125738/2019	Arguelles Depreciation Study	2020	Gas Depreciation Study
Tennessee	Tennessee Public Utility Commission	2000086	Piedmont Natural Gas	2020	Gas Depreciation Study
Texas	Railroad Commission of Texas	OS-00005136	CoServ Gas	2020	Gas Depreciation Study
Texas	Railroad Commission of Texas	GUD 10988	EPCOR Gas Texas	2020	Gas Depreciation Study
Florida	Florida Public Service Commission	20200166-GU	People Gas System	2020	Gas Depreciation Study
Mississippi	Federal Energy Regulatory Commission	ER20-1660-000	Mississippi Power Company	2020	Electric Depreciation Study
Texas	Public Utility Commission of Texas	50557	Corix Utilities	2020	Water and Waste Water Depreciation Study
Georgia	Georgia Public Service Commission	42959	Liberty Utilities Peach State Natural Gas	2020	Gas Depreciation Study
Texas	Public Utility Commission of Texas	50734	Oncor Electric Delivery	2020	Life of Intangible Plant
New Jersey	New Jersey Board of Public Utilities	GR20030243	South Jersey Gas	2020	Gas Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Kentucky	Kentucky Public Service Commission	2020-00064	Big Rivers	2020	Electric Depreciation Study
Colorado	Colorado Public Utilities Commission	20AL-0049G	Public Service of Colorado	2020	Gas Depreciation Study
Texas	NA	NA	Pedernales Electric Coop	2019	Electric Depreciation Study
New York	Federal Energy Regulatory Commission	ER20-716-000	LS Power Grid New York, Corp.	2019	Electric Transmission Depreciation Study
Mississippi	Mississippi Public Service Commission	2019-UN-219	Mississippi Power Company	2019	Electric Depreciation Study
Texas	Public Utility Commission of Texas	50288	Kerrville Public Utility District	2019	Electric Depreciation Study
Texas	Railroad Commission of Texas	GUD 10920	CenterPoint Gas	2019	Gas Depreciation Study and Propane Air Study
Texas, New Mexico	Federal Energy Regulatory Commission	ER20-277-000	Southwestern Public Service Company	2019	Electric Production and General Plant Depreciation Study
New Mexico	New Mexico Public Regulation Commission		New Mexico Gas	2019	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-19-086	Alaska Electric Light and Power	2019	Electric Depreciation Study
Texas	Railroad Commission of Texas	GUD 10900	Atmos Energy West Texas Division - Triangle	2019	Depreciation Rates for Natural Gas Property
Delaware	Delaware Public Service Commission	19-0615	Suez Water Delaware	2019	Water Depreciation Study
California	California Public Utilities Commission	A.19-08-015	Southwest Gas Northern California	2019	Gas Depreciation Study
California	California Public Utilities Commission	A.19-08-015	Southwest Gas Southern California	2019	Gas Depreciation Study
Texas	Railroad Commission of Texas	GUD 10895	CenterPoint Propane Air	2019	Depreciation Rates for Propane Air Assets
Texas	Public Utility Commission of Texas	49831	Southwestern Public Service Company	2019	Electric Depreciation Study
New Mexico	New Mexico Public Regulation Commission	19-00170-UT	Southwestern Public Service Company	2019	Electric Depreciation Study
Georgia	Georgia Public Service Commission	42516	Georgia Power Company	2019	Electric Depreciation Study
Georgia	Georgia Public Service Commission	42315	Atlanta Gas Light	2019	Gas Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Arizona	Arizona Corporation Commission	G-01551A-19-0055	Southwest Gas Corporation	2019	Gas Removal Cost Study
New Hampshire	New Hampshire Public Service Commission	DE 19-064	Liberty Utilities	2019	Electric Distribution and General
New Jersey	New Jersey Board of Public Utilities	GR19040486	Elizabethtown Natural Gas	2019	Gas Depreciation Study
Texas	Public Utility Commission of Texas	49421	CenterPoint Houston Electric LLC	2019	Electric Depreciation Study
North Carolina	North Carolina Utilities Commission	Docket No. G-9, Sub 743	Piedmont Natural Gas	2019	Gas Depreciation Study
Minnesota	Minnesota Public Utilities Commission	E-015/D-18-226	Allete Minnesota Power	2018	Electric Compliance Filing
Colorado	Colorado Public Utilities Commission	19AL-0063ST	Public Service of Colorado	2019	Steam Depreciation Study
Texas	NA	NA	CenterPoint Texas	2019	Propane Air Depreciation Study
Various	NA	NA	Enable Midstream Partners	2019	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-18-121	Municipal Power and Light City of Anchorage	2018	Electric Depreciation Study
Various	NA	NA	Pattern Energy	2018	Renewable Asset Capital Accounting
New York	NA	NA	Long Island Electric Utility Servco LLC	2018	Electric Depreciation Study
Various	FERC	RP19-352-000	Sea Robin	2018	Gas Depreciation Study
Texas New Mexico	Federal Energy Regulatory Commission	ER19-404-000	Southwestern Public Service Company	2018	Electric Transmission Depreciation Study
California	Federal Energy Regulatory Commission	ER19-221-000	San Diego Gas and Electric	2018	Electric Transmission Depreciation Study
Kentucky	Kentucky Public Service Commission	2018-00281	Atmos Kentucky	2018	Gas Depreciation Study
Texas	Public Utility Commission of Texas	48500	Golden Spread Electric Coop	2018	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-18-054	Matanuska Electric Coop	2018	Electric Generation Depreciation Study
California	California Public Utilities Commission	A17-10-007	San Diego Gas and Electric	2018	Electric and Gas Depreciation Study
Texas	NA	NA	Lower Colorado River Authority	2018	Electric Transmission and General Study
Texas	Public Utility Commission of Texas	48401	Texas New Mexico Power	2018	Electric Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Nevada	Public Utility Commission of Nevada	18-05031	Southwest Gas	2018	Gas Depreciation Study
Texas	Public Utility Commission of Texas	48231	Oncor Electric Delivery	2018	Depreciation Rates
Texas	Public Utility Commission of Texas	48371	Entergy Texas	2018	Electric Depreciation Study
Kansas	Kansas Corporation Commission	18-KCPE-480-RTS	Kansas City Power and Light	2018	Electric Depreciation Study
Louisiana	Louisiana Public Service Commission	U-34803	Atmos LGS	2018	Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	18-027-U	Liberty Pine Bluff Water	2018	Water Depreciation Study
Minnesota	Minnesota Public Utilities Commission	E-015/D-18-226	Allete Minnesota Power	2018	Electric Depreciation Rate
Kentucky	Kentucky Public Service Commission	2017-00349	Atmos KY	2018	Gas Depreciation Rates
Tennessee	Tennessee Public Utility Commission	18-00017	Chattanooga Gas	2018	Gas Depreciation Study
Texas	Railroad Commission of Texas	10679	Si Energy	2018	Gas Depreciation Study
Texas	City of Dallas Statement of Intent	NA	Atmos Mid-Tex	2017-2018	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-17-104	Anchorage Water and Wastewater	2017	Water and Waste Water Depreciation Study
Michigan	Michigan Public Service Commission	U-18488	Michigan Gas Utilities Corporation	2017	Gas Depreciation Study
New Mexico	FERC	ER18-228-000	Southwestern Public Service Company	2017	Electric Production Depreciation Study
Texas	Railroad Commission of Texas	10669	CenterPoint South Texas	2017	Gas Depreciation Study
New Mexico	New Mexico Public Regulation Commission	17-00255-UT	Southwestern Public Service Company	2017	Electric Production Depreciation Study
Arkansas	Arkansas Public Service Commission	17-061-U	Empire District Electric Company	2017	Depreciation Rates for New Wind Generation
Kansas	Kansas Corporation Commission	18-EPDE-184-PRE	Empire District Electric Company	2017	Depreciation Rates for New Wind Generation
Oklahoma	Oklahoma Corporation Commission	PUD 201700471	Empire District Electric Company	2017	Depreciation Rates for New Wind Generation
Missouri	Missouri Public Service Commission	EO-2018-0092	Empire District Electric Company	2017	Depreciation Rates for New Wind Generation

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Michigan	Michigan Public Service Commission	U-18457	Upper Peninsula Power Company	2017	Electric Depreciation Study
Florida	Florida Public Service Commission	20170179-GU	Florida City Gas	2017	Gas Depreciation Study
Iowa	NA		Cedar Falls Utility	2017	Telecommunications, Water, and Cable Utility
Michigan	FERC	ER18-56-000	Consumers Energy	2017	Electric Depreciation Study
Missouri	Missouri Public Service Commission	GR-2018-0013	Liberty Utilities	2017	Gas Depreciation Study
Michigan	Michigan Public Service Commission	U-18452	SEMCO	2017	Gas Depreciation Study
Texas	Public Utility Commission of Texas	47527	Southwestern Public Service Company	2017	Electric Production Depreciation Study
Minnesota	Minnesota Public Utilities Commission	17-581	Minnesota Northern States Power	2017	Electric, Gas and Common Transmission, Distribution and General
Colorado	Colorado Public Utilities Commission	17AL-0363G	Public Service of Colorado-Gas	2017	Gas Depreciation Study
MultiState	FERC	ER17-1664	American Transmission Company	2017	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-17-008	Municipal Power and Light City of Anchorage	2017	Generating Unit Depreciation Study
Louisiana	Louisiana Public Service Commission	U-34343	Atmos Trans Louisiana	2017	Gas Depreciation Study
Mississippi	Mississippi Public Service Commission	2017-UN-041	Atmos Energy	2017	Gas Depreciation Study
New York	FERC	ER17-1010-000	New York Power Authority	2017	Electric Depreciation Study
Oklahoma	Oklahoma Corporation Commission	PUD 201700078	CenterPoint Oklahoma	2017	Gas Depreciation Study
Texas	Railroad Commission of Texas	GUD 10580	Atmos Pipeline Texas	2017	Gas Depreciation Study
Texas	Public Utility Commission of Texas	46957	Oncor Electric Delivery	2017	Electric Depreciation Study
Alabama	FERC	ER16-2312-000	Alabama Power Company	2016	Electric Depreciation Study
Alabama	FERC	ER16-2313-000	SEGCO	2016	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-16-067	Alaska Electric Light and Power	2016	Generating Unit Depreciation Study
Arizona	Arizona Corporation Commission	G-01551A-16-0107	Southwest Gas	2016	Gas Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
California	California Public Utilities Commission	A 16-07-002	California American Water	2016	Water and Waste Water Depreciation Study
Colorado	Colorado Public Utilities Commission	16A-0231E	Public Service Company of Colorado	2016	Electric Depreciation Study
Mississippi	Mississippi Public Service Commission	2016 UN 267	Willmut Gas	2016	Gas Depreciation Study
Florida	Florida Public Service Commission	160170-EI	Gulf Power	2016	Electric Depreciation Study
Georgia	N/A	N/A	Dalton Utilities	2016	Electric, Gas, Water, Wastewater & Fiber Depreciation Study
Georgia	NA	NA	Oglethorpe Power	2016	Electric Depreciation Study
Illinois	Illinois Commerce Commission	GRM #16-208	Liberty-Illinois	2016	Natural Gas Depreciation Study
Iowa	Iowa Utilities Board	RPU-2016-0003	Liberty-Iowa	2016	Natural Gas Depreciation Study
Kentucky	FERC	RP16-097-000	KOT	2016	Natural Gas Depreciation Study
Michigan	Michigan Public Service Commission	U-18195	Consumers Energy/DTE Electric	2016	Ludington Pumped Storage Depreciation Study
Michigan	Michigan Public Service Commission	U-18127	Consumers Energy	2016	Natural Gas Depreciation Study
MultiState	FERC	ER17-191-000	American Transmission Company	2016	Electric Depreciation Study
Hawaii			Hawaii American Water	2015	Wastewater and Water Depreciation Study
New Jersey	New Jersey Board of Public Utilities	GR16090826	Elizabethtown Natural Gas	2016	Gas Depreciation Study
New York	NA		New York Power Authority	2016	Electric Transmission and General Study
North Carolina	North Carolina Utilities Commission	Docket G-9 Sub 77H	Piedmont Natural Gas	2016	Gas Depreciation Study
Texas	Railroad Commission of Texas	GUD 10567	CenterPoint Texas	2016	Gas Depreciation Study
Texas	Public Utility Commission of Texas	45414	Sharyland	2016	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-15-089	Fairbanks Water and Wastewater	2015	Water and Waste Water Depreciation Study
Arkansas	Arkansas Public Service Commission	15-098-U	CenterPoint Arkansas	2015	Gas Depreciation Study and Cost of Removal Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Arkansas	Arkansas Public Service Commission	15-031-U	Source Gas Arkansas	2015	Underground Storage Gas Depreciation Study
Hawaii			Hawaii American Water	2015	Wastewater and Water Depreciation Study
Arkansas	Arkansas Public Service Commission	15-011-U	Source Gas Arkansas	2015	Gas Depreciation Study
Atmos Energy Corporation	Tennessee Regulatory Authority	14-00146	Atmos Tennessee	2015	Natural Gas Depreciation Study
Colorado	Colorado Public Utilities Commission	15-AL-0299G	Atmos Colorado	2015	Gas Depreciation Study
Kansas	Kansas Corporation Commission	16-ATMG-079-RTS	Atmos Kansas	2015	Gas Depreciation Study
Kansas	Kansas Corporation Commission	15-KCPE-116-RTS	Kansas City Power and Light	2015	Electric Depreciation Study
Montana	NA	NA	Energy Keepers	2015	Property Units/ Depreciation Rates Hydro Facility
Multi-State NE US	FERC	16-453-000	Northeast Transmission Development, LLC	2015	Electric Depreciation Study
New Mexico	New Mexico Public Regulation Commission	15-00261-UT	Public Service Company of New Mexico	2015	Electric Depreciation Study
New Mexico	New Mexico Public Regulation Commission	15-00296-UT	Southwestern Public Service Company	2015	Electric Depreciation Study
New Mexico	New Mexico Public Regulation Commission	15-00139-UT	Southwestern Public Service Company	2015	Electric Depreciation Study
Texas	Railroad Commission of Texas	GUD 10432	CenterPoint- Texas Coast Division	2015	Gas Depreciation Study
Texas	Public Utility Commission of Texas	44704	Entergy Texas	2015	Electric Depreciation Study
Texas	Public Utility Commission of Texas	44746	Wind Energy Transmission Texas	2015	Electric Depreciation Study
Texas, New Mexico	FERC	ER15-949-000	Southwestern Public Service Company	2015	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-120	Alaska Electric Light and Power	2014-2015	Electric Depreciation Study
Alabama	State of Alabama Public Service Commission	U-5115	Mobile Gas	2014	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-045	Matanuska Electric Coop	2014	Electric Generation Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Alaska	Regulatory Commission of Alaska	U-14-054	Sand Point Generating LLC	2014	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-055	TDX North Slope Generating	2014	Electric Depreciation Study
California	California Public Utilities Commission	A.14-07-006	Golden State Water	2014	Water and Waste Water Depreciation Study
Colorado	Public Utilities Commission of Colorado	14AL-0660E	Public Service Company of Colorado	2014	Electric Depreciation Study
Louisiana	Louisiana Public Service Commission	U-28814	Atmos Energy Corporation	2014	Gas Depreciation Study
Michigan	Michigan Public Service Commission	U-17653	Consumers Energy Company	2014	Electric and Common Depreciation Study
Multi State – SE US	FERC	RP15-101	Florida Gas Transmission	2014	Gas Transmission Depreciation Study
Nebraska	Nebraska Public Service Commission	NG-0079	Source Gas Nebraska	2014	Gas Depreciation Study
New Mexico	New Mexico Public Regulation Commission	14-00332-UT	Public Service of New Mexico	2014	Electric Depreciation Study
Texas	Public Utility Commission of Texas	43950	Cross Texas Transmission	2014	Electric Depreciation Study
Texas	NA	NA	Hughes Natural Gas	2014	Gas Depreciation Study
Texas	Public Utility Commission of Texas	42469	Lone Star Transmission	2014	Electric Depreciation Study
Texas	Public Utility Commission of Texas	43695	Southwestern Public Service Company	2014	Electric Depreciation Study
Wisconsin	Wisconsin	05-DU-102	WE Energies	2014	Electric, Gas, Steam and Common Depreciation Studies
Texas, New Mexico	Public Utility Commission of Texas	42004	Southwestern Public Service Company	2013-2014	Electric Production, Transmission, Distribution and General Plant Depreciation Study
Virginia	Virginia Corporation Commission	PUE-2013-00124	Atmos Energy Corporation	2013-2014	Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	13-078-U	Arkansas Oklahoma Gas	2013	Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	13-079-U	Source Gas Arkansas	2013	Gas Depreciation Study
California	California Public Utilities Commission	Proceeding No.: A.13-11-003	Southern California Edison	2013	Electric Depreciation Study
Kentucky	Kentucky Public Service Commission	2013-00148	Atmos Energy Corporation	2013	Gas Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Minnesota	Minnesota Public Utilities Commission	13-252	Allete Minnesota Power	2013	Electric Depreciation Study
New Hampshire	New Hampshire Public Service Commission	DE 13-063	Liberty Utilities	2013	Electric Distribution and General
New Jersey	New Jersey Board of Public Utilities	GR13111137	South Jersey Gas	2013	Gas Depreciation Study
North Carolina/South Carolina	FERC	ER13-1313	Progress Energy Carolina	2013	Electric Depreciation Study
Oklahoma and TX Panhandle	NA	NA	Enable Midstream Partners	2013	Gas Depreciation Study
Texas	Public Utility Commission of Texas	41474	Sharyland	2013	Electric Depreciation Study
Texas	Railroad Commission of Texas	10235	West Texas Gas	2013	Gas Depreciation Study
Various	FERC	RP14-247-000	Sea Robin	2013	Gas Depreciation Study
Wisconsin	Public Service Commission of Wisconsin	4220-DU-108	Northern States Power Company - Wisconsin	2013	Electric, Gas and Common Transmission, Distribution and General
Alaska	Regulatory Commission of Alaska	U-12-154	Alaska Telephone Company	2012	Telecommunications Utility
Alaska	Regulatory Commission of Alaska	U-12-141	Interior Telephone Company	2012	Telecommunications Utility
Alaska	Regulatory Commission of Alaska	U-12-149	Municipal Power and Light City of Anchorage	2012	Electric Depreciation Study
Colorado	Colorado Public Utilities Commission	12AL-1269ST	Public Service Company of Colorado	2012	Gas and Steam Depreciation Study
Colorado	Colorado Public Utilities Commission	12AL-1268G	Public Service Company of Colorado	2012	Gas and Steam Depreciation Study
Kansas	Kansas Corporation Commission	12-ATMG-564-RTS	Atmos Kansas	2012	Gas Depreciation Study
Kansas	Kansas Corporation Commission	12-KCPE-764-RTS	Kansas City Power and Light	2012	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-17104	Michigan Gas Utilities Corporation	2012	Gas Depreciation Study
Minnesota	Minnesota Public Utilities Commission	12-858	Northern States Power Company - Minnesota	2012	Electric, Gas and Common Transmission, Distribution and General

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Nevada	Public Utility Commission of Nevada	12-04005	Southwest Gas	2012	Gas Depreciation Study
New Mexico	New Mexico Public Regulation Commission	12-00350-UT	Southwestern Public Service Company	2012	Electric Depreciation Study
North Carolina	North Carolina Utilities Commission	E-2 Sub 1025	Progress Energy Carolina	2012	Electric Depreciation Study
North Dakota	North Dakota Public Service Commission	PU-12-0813	Northern States Power	2012	Electric, Gas and Common Transmission, Distribution and General
South Carolina	Public Service Commission of South Carolina	Docket 2012-384-E	Progress Energy Carolina	2012	Electric Depreciation Study
Texas	Railroad Commission of Texas	10170	Atmos Mid-Tex	2012	Gas Depreciation Study
Texas	Railroad Commission of Texas	10147, 10170	Atmos Mid-Tex	2012	Gas Depreciation Study
Texas	Railroad Commission of Texas	10174	Atmos West Texas	2012	Gas Depreciation Study
Texas	Railroad Commission of Texas	10182	CenterPoint Beaumont/ East Texas	2012	Gas Depreciation Study
Texas	Texas Public Utility Commission	40604	Cross Texas Transmission	2012	Electric Depreciation Study
Texas	Texas Public Utility Commission	40020	Lone Star Transmission	2012	Electric Depreciation Study
Texas	Texas Public Utility Commission	40606	Wind Energy Transmission Texas	2012	Electric Depreciation Study
Texas	Texas Public Utility Commission	40824	Xcel Energy	2012	Electric Depreciation Study
California	California Public Utilities Commission	A1011015	Southern California Edison	2011	Electric Depreciation Study
Colorado	Public Utilities Commission of Colorado	11AL-947E	Public Service Company of Colorado	2011	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-16938	Consumers Energy Company	2011	Gas Depreciation Study
Michigan	Michigan Public Service Commission	U-16536	Consumers Energy Company	2011	Wind Depreciation Rate Study
Mississippi	Mississippi Public Service Commission	2011-UN-184	Atmos Energy	2011	Gas Depreciation Study
MultiState	FERC	ER12-212	American Transmission Company	2011	Electric Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
MultiState			Atmos Energy	2011	Shared Services Depreciation Study
MultiState			CenterPoint	2011	Shared Services Study
MultiState			CenterPoint	2011	Depreciation Reserve Study (SAP)
Pennsylvania	NA	NA	Safe Harbor	2011	Hydro Depreciation Study
Texas	Texas Public Utility Commission	39896	Entergy Texas	2011	Electric Depreciation Study
Texas	Public Utility Commission of Texas	38929	Oncor	2011	Electric Depreciation Study
Texas	Texas Commission on Environmental Quality	Matter 37050-R	Southwest Water Company	2011	WasteWater Depreciation Study
Texas	Texas Commission on Environmental Quality	Matter 37049-R	Southwest Water Company	2011	Water Depreciation Study
Alaska	Regulatory Commission of Alaska	U-10-070	Inside Passage Electric Cooperative	2010	Electric Depreciation Study
Georgia	Georgia Public Service Commission	31647	Atlanta Gas Light	2010	Gas Depreciation Study
Maine/ New Hampshire	FERC	10-896	Granite State Gas Transmission	2010	Gas Depreciation Study
Multi State – SE US	FERC	RP10-21-000	Florida Gas Transmission	2010	Gas Depreciation Study
Multistate	NA	NA	Constellation Energy	2010	Fossil Generation Depreciation Study
Multistate	NA	NA	Constellation Energy Nuclear	2010	Nuclear Generation Depreciation Study
Texas	Texas Railroad Commission	10041	Atmos Amarillo	2010	Gas Depreciation Study
Texas	Texas Railroad Commission	10000	Atmos Pipeline Texas	2010	Gas Depreciation Study
Texas	Railroad Commission of Texas	10038	CenterPoint South TX	2010	Gas Depreciation Study
Texas	Public Utility Commission of Texas	36633	City Public Service of San Antonio	2010	Electric Depreciation Study
Texas	Public Utility Commission of Texas	38339	CenterPoint Electric	2010	Electric Depreciation Study
Texas	Public Utility Commission of Texas	38147	Southwestern Public Service Company	2010	Electric Technical Update
Texas	Public Utility Commission of Texas	38480	Texas New Mexico Power	2010	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-09-015	Alaska Electric Light and Power	2009-2010	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-10-043	Utility Services of Alaska	2009-2010	Water Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
California	California Public Utility Commission	A10071007	California American Water	2009-2010	Water and Waste Water Depreciation Study
Michigan	Michigan Public Service Commission	U-16054	Consumers Energy	2009-2010	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-16055	Consumers Energy/DTE Energy	2009-2010	Ludington Pumped Storage Depreciation Study
Wyoming	Wyoming Public Service Commission	30022-148-GR10	Source Gas	2009-2010	Gas Depreciation Study
Colorado	Colorado Public Utilities Commission	09AL-299E	Public Service of Colorado	2009	Electric Depreciation Study
Iowa	NA		Cedar Falls Utility	2009	Telecommunications, Water, and Cable Utility
Michigan	Michigan Public Service Commission	U-15963	Michigan Gas Utilities Corporation	2009	Gas Depreciation Study
Michigan	Michigan Public Service Commission	U-15989	Upper Peninsula Power Company	2009	Electric Depreciation Study
Michigan	Michigan Public Service Commission	In Progress	Edison Sault	2009	Electric Depreciation Study
Mississippi	Mississippi Public Service Commission	09-UN-334	CenterPoint Energy Mississippi	2009	Gas Depreciation Study
New York	New York Public Service Commission		Key Span	2009	Generation Depreciation Study
North Carolina	North Carolina Utilities Commission		Piedmont Natural Gas	2009	Gas Depreciation Study
South Carolina	Public Service Commission of South Carolina		Piedmont Natural Gas	2009	Gas Depreciation Study
Tennessee	Tennessee Regulatory Authority	09-000183	AGL – Chattanooga Gas	2009	Gas Depreciation Study
Tennessee	Tennessee Regulatory Authority	11-00144	Piedmont Natural Gas	2009	Gas Depreciation Study
Texas	Railroad Commission of Texas	9869	Atmos Energy	2009	Shared Services Depreciation Study
Texas	Railroad Commission of Texas	9902	CenterPoint Energy Houston	2009	Gas Depreciation Study
Arizona	NA	NA	Arizona Public Service	2008	Fixed Asset Consulting
Louisiana	Louisiana Public Service Commission	U-30689	Cleco	2008	Electric Depreciation Study
Multiple States	NA	NA	Constellation Energy	2008	Generation Depreciation Study
New Mexico	New Mexico Public Regulation Commission	07-00319-UT	Southwestern Public Service Company	2008	Testimony – Depreciation

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
North Dakota	North Dakota Public Service Commission	PU-07-776	Northern States Power Company - Minnesota	2008	Net Salvage
Texas	Public Utility Commission of Texas	35717	Oncor	2008	Electric Depreciation Study
Texas	Public Utility Commission of Texas	35763	Southwestern Public Service Company	2008	Electric Production, Transmission, Distribution and General Plant Depreciation Study
Wisconsin	Wisconsin	05-DU-101	WE Energies	2008	Electric, Gas, Steam and Common Depreciation Studies
Colorado	Colorado Public Utilities Commission	Filed – no docket to date	Public Service Company of Colorado	2007-2008	Electric Depreciation Study
Colorado	Colorado Public Utilities Commission	10AL-963G	Public Service Company of Colorado	2007-2008	Gas Depreciation Study
Minnesota	Minnesota Public Utilities Commission	E015/D-08-422	Minnesota Power	2007-2008	Electric Depreciation Study
Multiple States	Railroad Commission of Texas	9762	Atmos Energy	2007-2008	Shared Services Depreciation Study
Multiple States	None		Tennessee Valley Authority	2007-2008	Electric Generation and Transmission Depreciation Study
Michigan	Michigan Public Service Commission	U-15629	Consumers Energy	2006-2009	Gas Depreciation Study
Multiple States	NA	NA	Constellation Energy	2007	Generation Depreciation Study
Texas	Public Utility Commission of Texas	34040	Oncor	2007	Electric Depreciation Study
Arkansas	Arkansas Public Service Commission	06-161-U	CenterPoint Energy – Arkla Gas	2006	Gas Distribution Depreciation Study and Removal Cost Study
Colorado	Colorado Public Utilities Commission	06-234-EG	Public Service Company of Colorado	2006	Electric Depreciation Study
Multiple States	Multiple	NA	CenterPoint Energy	2006	Shared Services Depreciation Study
Nevada	NA	NA	Nevada Power/Sierra Pacific	2006	ARO Consulting

2022 RATE CASE
ONCOR ELECTRIC DELIVERY COMPANY LLC
EXHIBIT DAW-2, Book Depreciation Accrual Rate Study
FOR THE TEST YEAR ENDING December 31, 2021
SPONSOR: DANE A. WATSON

ONCOR

ALLIANCE
CONSULTING GROUP

ONCOR ELECTRIC DELIVERY COMPANY LLC
DEPRECIATION RATE STUDY
AT DECEMBER 31, 2021

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PURPOSE

The purpose of this study is to develop depreciation rates for the depreciable transmission, distribution, and general property as recorded on the books of Oncor Electric Delivery Company ("Oncor" or "Company") as of December 31, 2021. The depreciation rates were designed to recover the total remaining undepreciated investment, adjusted for net salvage, over the remaining life of Oncor's property on a straight-line basis. Non-depreciable property, property being recovered through the leasehold agreements, and any assets with a remaining net book value from the AMS surcharge were excluded from this study. Oncor is a regulated electric transmission and distribution company principally engaged in providing delivery services to retail electric providers ("REPs") that sell power in the north-central, eastern, and western parts of Texas. Oncor provides the essential service of delivering electricity safely, reliably, and economically to end-use consumers through its distribution systems, as well as providing transmission grid connections to merchant power plants and interconnection to other transmission grids in Texas.

The assets for Oncor have changed since the last depreciation study was adjudicated in Docket No. 46957. In Oncor's last base rate, Docket No. 46957, the Commission's Order was predicated on Oncor and the company known at that time as Sharyland Distribution & Transmission Services, LLC ("Sharyland") reaching closing on a transaction to exchange assets (Oncor was to acquire primarily distribution assets, while Sharyland was to receive certain Oncor CREZ transmission assets). The Sharyland transaction did close, and the asset exchange took place in 2017.

Additionally, in Docket No. 48929, the Commission approved a transaction that resulted in Oncor's acquisition of the electric transmission assets previously held by Sharyland and/or Sharyland Utilities, L.P., and a new wholly owned subsidiary of Oncor, Oncor Electric Delivery Company NTU LLC ("Oncor NTU"), was created to hold those assets. The assets now held by Oncor NTU include mostly transmission, distribution, and general plant. The Oncor NTU assets are currently being depreciated at the depreciation rates approved for Sharyland in Docket No. 45414, which retained the existing depreciation rates from Docket No. 41474. I have prepared one depreciation study that combines Oncor and Oncor NTU assets. At the Company's direction, this study recommends one set of combined depreciation and amortization rates to be applied to both companies, since Oncor will operate, maintain, and construct Oncor NTU transmission facilities consistent with the same business practices currently used by Oncor.

STUDY RESULTS

Depreciation and amortization rates for assets currently being recovered through the AMS surcharge are addressed by Oncor's accounting witness Mr. W. A. Ledbetter. The recommended depreciation rates for all other Oncor depreciable property (excluding meter surcharge-related assets) are shown in Exhibit DAW-2, Appendix A (Appendix A). These rates translate into an annual depreciation accrual for Intangible, Transmission, Distribution, and General plant of approximately $897.1 million, excluding the AMS-deployed assets that were being recovered through the AMS surcharge before the surcharge ceased. Exhibit DAW-2, Appendix B (Appendix B) shows a comparison of current versus proposed depreciation expense by account. In Appendix B, this study includes the amortization and depreciation rates recommended by Witness Ledbetter for assets were being recovered through the AMS surcharge before the surcharge ceased These accruals are based on Oncor's depreciable investment at December 31, 2021. The proposed lives and curves on which these calculations are based are shown in Exhibit DAW-2, Appendix C (Appendix C), and the remaining lives based on these parameters are shown in Exhibit DAW-2, Appendix D (Appendix D). Also shown in Appendix D are the calculations of Vintage Group amortization rates for General Plant assets. Appendix B shows the effect of the change in lives and curves on depreciation accrual by account. Appendix E (Appendix E) addresses the development of net salvage parameters for all plant accounts.

Oncor adopted Vintaged Group Amortization consistent with FERC Rule AR-15 as of January 1, 2008. The General Plant accounts where Oncor adopted Vintaged Group Amortization are Accounts 391 through 398 (excluding a portion of Account 397). This process provides for the amortization of general plant over the same life as recommended in this study, with a separate amortization to allocate deficit or excess reserve as necessary. At the end of the amortized life, property will be retired from the books. Implementation of this approach did not affect the annual expense accrued by Oncor and provides for the timely retirement of assets and the simplification of accounting for general property. The use of Vintage Group Amortization was approved by the Public Utility Commission of

Texas in Docket No. 35717, and this study continues the use of the same methodology for those accounts. The study's workpapers include the amortization schedules for this approach. However, in the Vintage Group Amortization accounts, there has been a change in the assets within Accounts 391 (Office Furniture and Equipment), 392 (Transportation Equipment), and Account 394 (Tools, Shop, and Garage, Equipment). In Account 391, 93 percent of the assets are Computer Equipment and other Technology related assets (a dramatic increase since the time that the original life and depreciation rate was established). Computer equipment has a shorter life than the currently used 15-year life for furniture and equipment account. In Account 392, the assets have been divided into subsets that have more similar characteristics: automobiles/ light trucks, heavy trucks, and trailers, which have proposed lives of 7, 10, and 15 years respectively. In Account 394, 55% of the current assets are small tools, which have a shorter life than the currently used 35 years. Certain accounts were not included in the scope of the depreciation study, such as leasehold improvements and non-depreciable land in Accounts 349, 374, and 388. The table below recaps the changes by functional group.

2022 RATE CASE
ONCOR TOTAL
COMPARISON OF DEPRECIATION RATES
FOR THE TEST YEAR ENDING DECEMBER 31, 2021

Function	Original Cost	Existing Annual Accrual	Proposed Annual Accrual	Difference
	$	$	$	$
Intangible	$ 920,182,465	$ 57,858,477	$ 79,420,212	$ 21,561,735
Transmission	12,954,286,845	374,568,318	324,561,451	(50,006,866)
Distribution Substation	2,666,947,433	47,956,303	55,631,763	7,675,460
Distribution	13,012,776,489	349,146,802	376,623,772	27,476,969
General	859,675,800	33,453,919	60,839,924	27,386,005
Total	30,413,869,031	862,983,819	897,077,121	34,093,303

Plant amounts exclude AMS surcharge assets, leasehold improvements, and non-depreciable plant.

GENERAL DISCUSSION

Definition

The term "depreciation" as used in this study is considered in the accounting sense; that is, a system of accounting that distributes the cost of assets, less net salvage (if any), over the estimated useful life of the assets in a systematic and rational manner. It is a process of allocation, not valuation. This expense is systematically allocated to accounting periods over the life of the properties. The amount allocated to any one accounting period does not necessarily represent the loss or decrease in value that will occur during that particular period. The Company accrues depreciation on the basis of the original cost of all depreciable property included in each functional property group. At retirement, the full cost of depreciable property, less the net salvage value, is charged to the depreciation reserve.

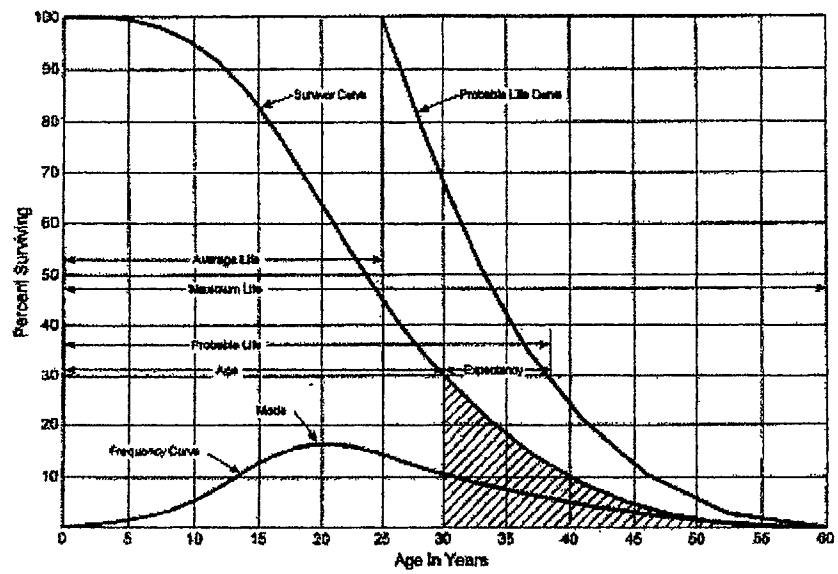
Basis of Depreciation Estimates

Annual and accrued depreciation were calculated in this study by the straight-line, broad group, remaining-life depreciation system. In this system, the annual depreciation expense for each group is computed by dividing the original cost of the asset group (less allocated depreciation reserve less estimated net salvage) by its respective average remaining life. The resulting annual accrual amounts were divided by the original cost of the depreciable property in each account to determine the depreciation rate. The calculated remaining lives and annual depreciation accrual rates were based on attained ages of plant in service and the estimated service life and salvage characteristics of each depreciable group and were computed in a direct weighting by multiplying each vintage or account balance times its remaining life and dividing by the plant investment in service at December 31, 2021. The computations of the annual depreciation rates are shown in Appendix A, and the weighted remaining life calculations are shown in Appendix D.

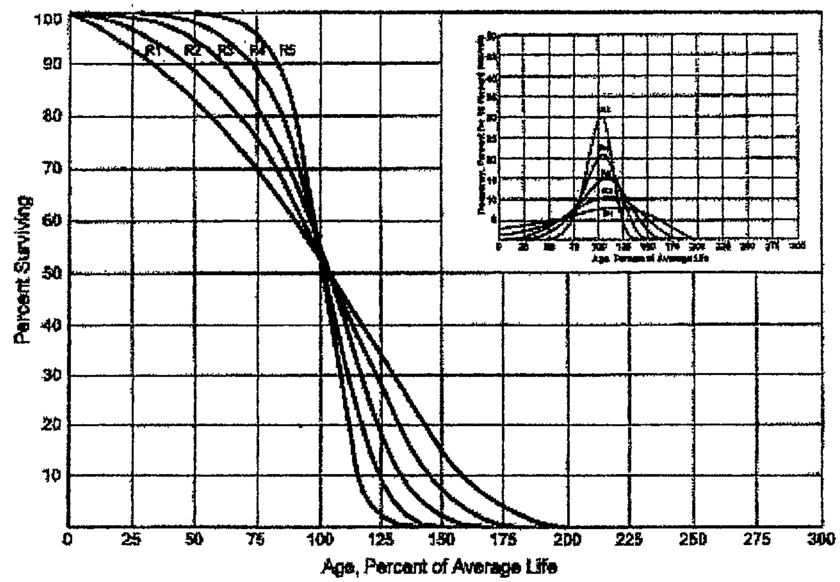
A variety of life estimation approaches were incorporated into the analyses of Oncor data. Simulated Plant Record (SPR) analysis and Actuarial Analysis are both mortality analysis techniques commonly used for electric utility property. In depreciation studies prior to Docket No. 35717, Oncor has used SPR analysis to evaluate lives of most asset groups. In Docket No. 35717, actuarial analysis was used for Accounts 353-356 and 362 and for General accounts. In Docket 46957, rapid growth in the Transmission and Distribution substation account made the data base of aged retirements insufficient for actuarial analysis. This depreciation study uses both actuarial and SPR analysis for Accounts 353-362. This issue will be discussed more in a later section of this report. Mass Distribution accounts (Account 364 – 369 and 371-373) were analyzed using SPR analysis. For the accounts using actuarial analysis, experience bands varied depending on the amount of data. The widest possible experience band varied depending on the historic data available: the 1990-2021 experience band was the widest used for Account 390 (Structures and Improvements); the 2000-2021 experience band was the widest used for Account 397 (Communication Equipment Depreciable); and the 2009-2021 experience band was the widest used for Account 370 (Meters), excluding AMS. Judgment was used to a greater or lesser degree on all accounts. Each approach used in this study is more fully described in a later section.

Survivor Curves

To fully understand depreciation projections in a regulated utility setting, there must be a basic understanding of survivor curves. Individual assets within a group do not normally have identical lives or investment amounts. The average life of a group can be determined by comparing actual experience against various survivor curves. A survivor curve represents the percentage of property remaining in service at various age intervals. The most widely used set of representative survivor curves are the Iowa Survivor Curves (Iowa Curves). The Iowa Curves are the result of an extensive investigation of life characteristics of physical property made at Iowa State College Engineering Experiment Station in the first half of the twentieth century. Through common usage, revalidation, and regulatory acceptance, these curves have become a descriptive standard for the life characteristics of industrial property. An example of an Iowa Curve is shown below.



There are four families in the Iowa Curves which are distinguished by the relation of the age at the retirement mode (largest annual retirement frequency) and the average life. The four families are designated as "R"— Right, "S" — Symmetric, "L" — Left, and "O" — Origin Modal. First, for distributions with the mode age greater than the average life, an "R" designation (i.e., Right modal) is used. The family of "R" moded curves is shown below.



Second, an "S" designation (i.e., Symmetric modal) is used for the family whose mode age is symmetric about the average life. Third, an "L" designation (i.e., Left modal) is used for the family whose mode age is less than the average life. Fourth, a special case of left modal dispersion is the "O" or origin modal curve family. Within each curve family, numerical designations are used to describe the relative magnitude of the retirement frequencies at the mode. A "6" indicates that the retirements are not greatly dispersed from the mode (i.e., high mode frequency) while a "1" indicates a large dispersion about the mode (i.e., low mode frequency). For example, a curve with an average life of 30 years and an "L3" dispersion is a moderately dispersed, left modal curve that can be designated as a 30 L3 Curve. An SQ, or square, survivor curve occurs where no dispersion is present (i.e., units of common age retire simultaneously).

For Transmission, Distribution, and General Property accounts, a survivor curve pattern was selected based on analyses of historical data, as well as other factors, such as general changes relevant to the Company's operations. The blending of judgment concerning current conditions and future trends, along with the matching of historical data permits the depreciation analyst to make an informed selection of an account's average life and retirement dispersion pattern. Iowa Curves were used to depict the estimated survivor curves for each account.

Actuarial Analysis

Actuarial analysis (retirement rate method) was used in evaluating historical asset retirement experience where vintage data were available and sufficient retirement activity was present. In actuarial analysis, interval exposures (total property subject to retirement at the beginning of the age interval, regardless of vintage) and age interval retirements are calculated. The complement of the ratio of interval retirements to interval exposures establishes a survivor ratio. The survivor ratio is the fraction of property surviving to the end of the selected age interval, given that it has survived to the beginning of that age interval. Survivor ratios for all of the available age intervals were chained by successive multiplications to establish a series of survivor factors, collectively known as an observed life table. The observed life table shows the experienced mortality characteristic of the account and may be compared to standard mortality curves such as the Iowa Curves. Many accounts were analyzed using this method. Placement bands were used to illustrate the composite history over a specific era, and experience bands were used to focus on retirement history for all vintages during a set period. Matching data in observed life tables for each experience and placement band to an Iowa Curve requires visual examination. As stated in Depreciation Systems by Wolf and Fitch, "the analyst must decide which points or sections of the curve should be given the most weight. Points at the end of the curve are often based on fewer exposures and may be given less weight than those points based on larger samples" (page 46). Some analysts chose to use mathematical fitting as a tool to narrow the population of curves using a least squares technique. Use of the least squares approach does not imply a statistical validity, however, because the underlying data does not meet criteria for independence between vintages and the same average price for property units through time. Thus, Depreciation Systems cautions, "... the results of mathematical fitting should be checked visually and the final determination of best fit made by the analyst" (page 48). This study uses the visual matching approach to match Iowa Curves, since mathematical fitting produces theoretically possible curve matches. Visual examination and experienced judgment allow the depreciation professional to make the final determination as to the best curve type.

Detailed information for each account is shown later in this study and in workpapers.

Simulated Plant Record Procedure

The SPR - Balances approach is one of the commonly accepted approaches to analyze mortality characteristics of utility property. SPR was applied to several accounts within the Distribution function due to the unavailability of vintaged transactional data. In this method, an Iowa Curve and average service life are selected as a starting point of the analysis and its survivor factors applied to the actual annual additions to give a sequence of annual balance totals. These simulated balances are compared with the actual balances by using both graphical and statistical analysis. Through multiple comparisons, the mortality characteristics (as defined by an average life and Iowa Curve) that are the best match to the property in the account can be found.

The Conformance Index (CI) is one measure used to evaluate various SPR analyses. CIs are also used to evaluate the "goodness of fit" between the actual data and the Iowa Curve being referenced. The sum of squares difference (SSD) is a summation of the difference between the calculated balances and the actual balances for the band or study year being analyzed. This difference is squared and then summed to arrive at the SSD.

$$SSD = \sum_{1}^{n} (Calculated\ Balance_i - Observed\ Balance_i)^2$$

Where n is the number of years in the test band.

This calculation can then be used to develop other calculations, which the analyst feels might give a better indication for the "goodness of fit" for the representative curve under consideration. The residual measure (RM) is the square root of the average squared differences as developed above. The residual measure is calculated as follows:

$$\boxed{RM = \sqrt{\left(\frac{SSD}{n}\right)}}$$

The CI is developed from the residual measure and the average observed plant balances for the band or study year being analyzed. The calculation of conformance index is shown below:

$$CI = \frac{\sum_1^n Balances_i / n}{RM}$$

The retirement experience index (REI) gives an indication of the maturity of the account and is the percent of the property retired from the oldest vintage in the band at the end of the study year. Retirement indices range from 0 percent to 100 percent and an REI of 100 percent indicates that a complete curve was used. A retirement index less than 100 percent indicates that the survivor curve was truncated at that point. The originator of the SPR method, Alex Bauhan, suggests ranges of value for the CI and REI. The relationship for CI proposed by Bauhan is shown below[1]:

CI	Value
Over 75	Excellent
50 to 75	Good
25 to 50	Fair
Under 25	Poor

The relationship for REI proposed by Bauhan[2] is shown below:

REI	Value
Over 75	Excellent
50 to 75	Good
33 to 50	Fair
17 to 33	Poor
Under 17	Valueless

Despite the fact there has not been empirical research to validate Bauhan's conclusions, depreciation analysts have used these measures in analyzing SPR results for nearly 60 years, since the SPR method was developed.

[1] Public Utility Depreciation Practices, p. 96.
[2] Public Utility Depreciation Practices, p. 97.

Each of these statistics provides the analyst with a different perspective of the comparison between a band of simulated or calculated balances and the observed or actual balances in the account being studied. Although one statistic is not necessarily superior over the others, the conformance index is the one many analysts use in depreciation studies. The depreciation analyst should carefully weigh the data from REIs to ensure that a mature curve is being used to estimate life.

Statistics are useful in analyzing mortality characteristics of accounts as well as determining a range of service lives to be analyzed using the detailed graphical method. However, these statistics reduce the information down to one, or at most, a few numbers for comparison. Visual matching through comparison between actual and calculated balances expands the analysis by permitting the analyst to view many points of data at a time. The goodness of fit should be visually compared to plots of other Iowa Curve dispersions and average lives for the selection of the appropriate curve and life. Detailed information for each account is shown later in this study and in workpapers.

Judgment

Any depreciation study requires informed judgment by the analyst conducting the study. A knowledge of the property being studied, company policies and procedures, general trends in technology and industry practice, and a sound basis of understanding depreciation theory are needed to apply this informed judgment. In this depreciation study, judgment was used in areas such as survivor curve modeling and selection, depreciation method selection, simulated plant record method analysis, and actuarial analysis.

Where there are multiple factors, activities, actions, property characteristics, statistical inconsistencies, property mix in accounts or a multitude of other considerations that affect the analysis (potentially in various directions), judgment is used to take all of these considerations and synthesize them into a general direction or understanding of the characteristics of the property.

Individually, no one consideration in these cases may have a substantial impact on the analysis, but overall, the collective effect of these considerations may shed light on the use and characteristics of assets. Judgment may also be defined as deduction, inference, wisdom, common sense, or the ability to make sensible decisions. There is no single correct result from statistical analysis; hence, there is no answer absent judgment.

Theoretical Depreciation Reserve

The book accumulated provision for depreciation within each function was allocated among transmission, distribution, and general accounts through the use of the theoretical depreciation reserve model. This study used a reserve model that relied on a prospective concept relating future retirement and accrual patterns for property, given current life and salvage estimates.

The theoretical reserve of a property group is developed from the estimated remaining life of the group, the total life of the group, and estimated net salvage. The theoretical reserve represents the portion of the group cost that would have been accrued if current forecasts were used throughout the life of the group for future depreciation accruals. The computation involves multiplying the vintage balances within the group by the theoretical reserve ratio for each vintage. The straight-line remaining-life theoretical reserve ratio at any given age (RR) is calculated as:

$$RR = 1 - \frac{(Average\ Remaining\ Life)}{(Average\ Service\ Life)} * (1 - Net\ Salvage\ Ratio)$$

DETAILED DISCUSSION

Depreciation Study Process

This depreciation study encompassed four distinct phases. The first phase involved data collection and field interviews. The second phase was where the initial data analysis occurred. The third phase was where the information and analysis were evaluated. After the first three stages were complete, the fourth phase began. This phase involved the calculation of deprecation rates and documentation of the corresponding recommendations.

During the Phase 1 data collection process, historical data was compiled from continuing property records and general ledger systems. Data was validated for accuracy by extracting and comparing to multiple financial system sources: Projects System (Construction ledger), Fixed Asset System (continuing property ledger), General Ledger, and interfaces from other operating systems. Audit of this data was validated against historical data from prior periods, historical general ledger sources, and field personnel discussions. This data was reviewed extensively so that it could be put in the proper format for a depreciation study. Further discussion on data review and adjustment is found in the Salvage Consideration section of this study. Also as part of the Phase 1 data collection process, numerous discussions were conducted with engineers and field operations personnel to obtain information that would be helpful in formulating life and salvage recommendations in this study. One of the most important elements in performing a proper depreciation study is to understand how the Company utilizes assets and the environment of those assets. Understanding industry and geographical norms for mortality characteristics are important factors in selecting life and salvage recommendations; however, care must be used not to apply them rigorously to any particular company since no two companies would have the same exact forces of retirement acting upon their assets. Interviews with engineering and operations personnel are important in allowing the analyst to obtain information that is helpful when evaluating the output from the life and net salvage programs in relation to the Company's actual asset utilization and environment. Information that was gleaned in these discussions is found both in the Detailed Discussion portions of the Life Analysis and Salvage Analysis sections, and also in workpapers. In addition, Alliance personnel possess a significant understanding of the property and its forces of retirement due to years of day-to-day exposure to property and operations of electric utility property.

Phase 2 is where the SPR and actuarial analysis were performed. Phase 2 and Phase 3 (to be discussed in the next paragraph) overlap to a significant degree. The detailed property records information was used in Phase 2 to develop observed life tables for life analysis and SPR graphs and statistics. Net salvage analysis consists of compiling historical salvage and removal data by account to determine values and trends in gross salvage and removal cost. This information was then carried forward into Phase 3 for the evaluation process.

Phase 3 is the evaluation process, which synthesized analysis, interviews, and operational characteristics into a final selection of asset lives and net salvage parameters. The historical analysis from Phase 2 was further enhanced by the incorporation of recent or future changes in the characteristics or operations of assets that were revealed in Phase 1. The preliminary results were then reviewed and discussed with accounting and operations personnel. Phases 2 and 3 validated the asset characteristics as seen in the accounting transactions with actual Company operational experience.

Finally, Phase 4 involved the calculation of accrual rates, making recommendations and documenting the conclusions in a final report. The calculation of accrual rates is found in Appendix A. Recommendations for the various accounts are contained within the detailed discussion section of this report. The depreciation study flow diagram shown as Figure 1[3] documents the steps used in conducting this study. Depreciation Systems,[4] documents the same basic processes in performing a depreciation study which are: a statistical analysis, evaluation of statistical analysis, discussions with management, forecast

[3] Introduction to Depreciation for Public Utilities and Other Industries, AGA EEI, 2013

[4] Wolf & Fitch, Depreciation Systems, Iowa State Press, 1994, p. 289.

assumptions, writes logic supporting forecasts and estimation, and writes final report.

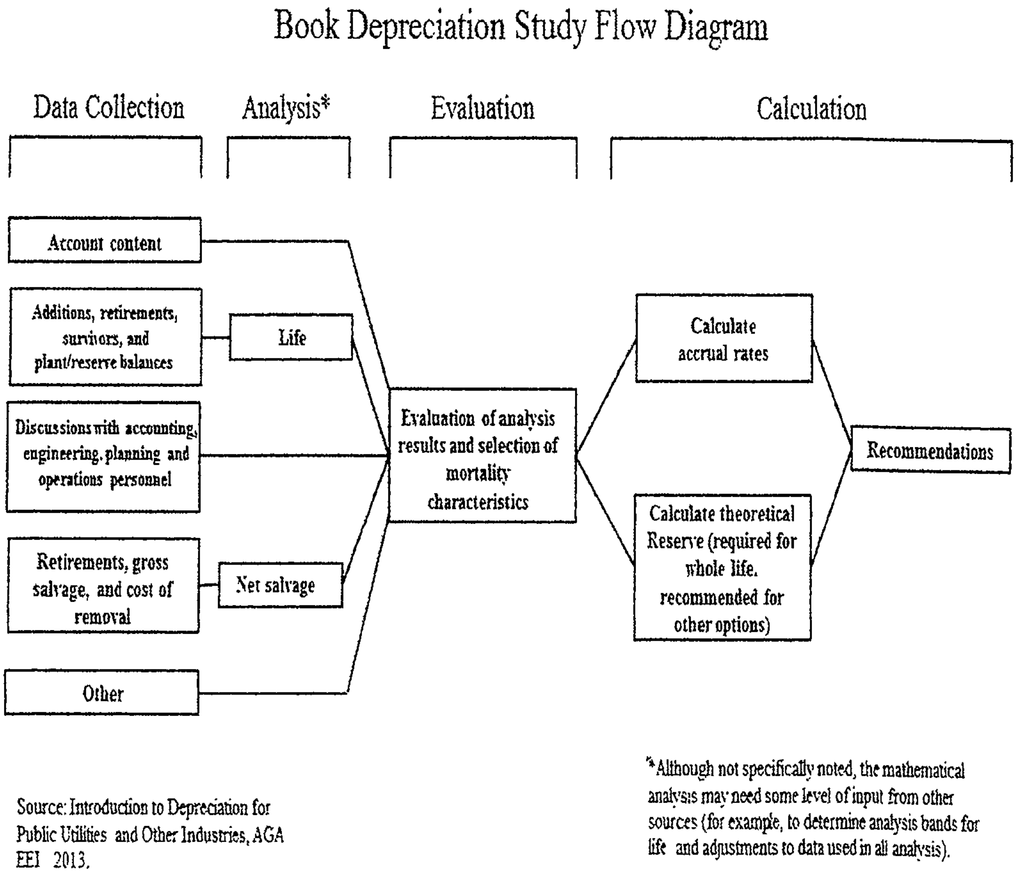


Figure 1

ONCOR ELECTRIC DELIVERY
DEPRECIATION STUDY PROCESS

Transmission, Distribution and General Calculation Process

Annual depreciation expense amounts for Transmission excluding Substations, Transmission Substations, Distribution Substation, Distribution excluding Substations, and General accounts were calculated by the straight line, remaining life depreciation system.

In a whole life representation, the annual accrual rate is computed by the following equation,

$$AnnualAccrualRate = \frac{(100\% - NetSalvagePercent)}{AverageServiceLife}$$

Use of the remaining life depreciation system adds a self-correcting mechanism, which accounts for any differences between theoretical and book depreciation reserve over the remaining life of the group. With the straight line, remaining life, average life group system using Iowa Curves, composite remaining lives were calculated according to standard broad group expectancy techniques, noted in the formula below:

$$Composite\,\mathrm{Re}\,mainingLife = \frac{\sum V\,\mathrm{int}\,ageOriginalCost * \mathrm{Re}\,mainingLife}{\sum TotalOriginalCost}$$

For each plant account, the difference between the surviving investment, adjusted for estimated net salvage, and the allocated book depreciation reserve, was divided by the composite remaining life to yield the annual depreciation expense as noted in this equation.

$$AnnualDepreciationExpense = \frac{OriginalCost - Book\,\mathrm{Re}\,serve - (OriginalCost) * (1 - NetSalvage\%)}{Composite\,\mathrm{Re}\,mainingLife}$$

where the net salvage percent represents future net salvage.

Within a group, the sum of the group annual depreciation expense amounts, as a percentage of the depreciable original cost investment summed, gives the annual depreciation rate as shown below:

$$AnnualDepreciationRate = \frac{\sum AnnualDepreciationExpense}{\sum OriginalCost}$$

These calculations are shown in Appendix A. The calculations of the theoretical depreciation reserve values and the corresponding remaining life calculations are shown in Appendix D. Book depreciation reserves are maintained on a function level basis and theoretical reserve computation was used to compute composite remaining life and allocated depreciation for each account.

LIFE ANALYSIS

Account 303 Intangible Plant

In Docket No. 35717, the Company began to depreciate its intangible assets using group depreciation. In Docket 46957, the assets in this account were stratified into three separate groups: 5-year, 8-year, and 15-year life assets. In this deprecation study, two additional changes are recommended. For the first change, a 3-year category has been added to the other categories. The second change adds an Iowa Curve dispersion that models the fact that some assets within each group will retire at a different age within each subgroup. All subgroups are proposed to have an R2 dispersion. Company subject matter experts with the Technology group assesses and assigns depreciable lives to the technology systems and assets it manages based on a review of various criteria, including significant changes associated digital security risks; the software support lifecycle policies maintained by the major third-party vendors, such as IBM, Oracle, and Microsoft; the anticipated life of the functions provided by the technology systems or assets; the maximum term of an agreement provided by the vendor; and the categorization of the technology system or asset.

The Technology group continues to monitor trends in the software industry relating to product lifecycles, such as trends in technical support and licensing models. Since Oncor's last base-rate case, as part of the Technology group's ongoing review of the depreciable lives, it has determined that it is still appropriate to continue using the five-year, eight-year, and 15-year life categories that have historically been used, but the Technology group is proposing that a new three-year life group category be used for hosted software applications with three-year fixed-term agreements. Hosted software applications include those applications that are either owned by a third party and licensed by the Technology group for a fixed period of time, or that are owned by Oncor but were developed by a third party and are hosted by the third party for a fixed period of time. During this review, the Technology group determined that the third parties who provide hosting services would only support three- or five-year fixed terms agreements, resulting

in the need for a new 3-year life group category.

In conducting its comprehensive review of service life groups for technology systems and assets, the Technology group primarily relied on vendor-defined premier technical support criteria or fixed-term agreements. For applets that are coded on vendor server-based software applications, the applet assumes the same service life group as the vendor application due to its dependency on the application. The rationale in reviewing and adjusting where appropriate the 15-year service life group is comprised of several factors. For an Oncor-developed and -owned software application, the service life determination is based on the software application's development lifecycle, which includes current industry-defined premier technical support criteria as a reference, plus the time used to develop new or enhanced functionality. For a software system assigned a 15-year service life, the assignment determination is based on several factors including each component's vendor-defined premier technical support criteria and the impact of enhancing or replacing one of the components (which ultimately requires a re-architecture of the system's end-to-end processes, cybersecurity protection and controls, infrastructure, integration services, and new functional requirements). As an example, based on these factors, the Technology group assigned a 15-year service life group to the Customer Care and Billing System project.

The Technology group is currently assigning end-use computer applications and hosted software applications with five-year fixed term agreements to the five-year service life group. Vendor server-based software applications or Oncor-coded applets using a vendor's server-based software application are assigned to the eight-year service life group. Oncor-developed and -owned software applications or software systems are assigned to the 15-year service life group. The Technology group considers a software system to be a logical grouping of integrated software applications used to support specific functional requirements that cannot be accomplished by an individual application or its features.

After Docket 46957, the Company installed large systems for Customer Care and Billing ("CC&B") and Aegis. In the distribution cost recovery ("DCRF") cases, the Company proposed a 15-year life and settlement agreements adopted a settlement life of 25 years. In this proceeding, those assets are recommended to have a 15-year life. This review took place under the direction of Company Senior Vice President and Chief Information Officer, who provided the categorization by life to me in order to set depreciation rates for each subgroup.

The table below shows the plant amounts categorized by sub-group.

Asset Type	Plant at 12/31/21
Intangible 3 year	408,078
Intangible 5 year	32,215,865
Intangible 8 year	328,240,028
Intangible 15 year	559,318,494

Transmission Accounts, FERC Accounts 350-358

The transmission business unit has experienced significant changes in load and operations since deregulation began. Prior to 2002, TXU Electric Company would dispatch its own generation across the system in conjunction with the operation of the transmission system. On January 1, 2002, TXU Electric Company was unbundled into three separate business units, with Oncor becoming a transmission and distribution utility.

ERCOT (Electric Reliability Council of Texas) is the grid operator across most of the state. Utilities are experiencing changing patterns of load and sources of generation that must go across the transmission system. In 2000-2002, the focus of capital expenditures was on growth, connections to new independent power producers, and other interconnects. Much of the construction during 2000-2002 involved new 345 kV lines and transmission substations. In 2003-2007, Oncor began a concentrated effort of rebuilding transmission lines, transmission substations, and distribution substations in the Metroplex area. This rebuilding activity has continued since 2007 with the exception of the 2009-2013 period where the focus was on Competitive Renewable Energy Zones (CREZ).

The CREZ is an area where renewable generation facilities will be installed and from which transmission facilities were built to various other areas of the state to deliver renewable power to end-user customers in the most cost-effective manner. The CREZ project is the Public Utility Commission (PUC) of Texas' response to a public mandate to increase renewable energy in Texas to serve the electric needs of the state.

The Texas Legislature passed Senate Bill (SB) 7 in 1999, which restructured the state's electric industry. As a result of SB 7, the Texas Legislature established a renewable portfolio standard for electric power generation, with the intent to install more than 2,000 megawatts (MW) of generation capacity form renewable energy technologies by Jan.1, 2009. Through Senate Bill 20 (SB 20), in 2005 the Texas Legislature raised the amount of renewable power generation to nearly 6,000 MW to be installed by Jan 1, 2015.

SB 20 further requires the PUC to set a target of 10,000 MW of renewable generation capacity by Jan. 1, 2025. Ultimately the CREZ effort allowed Texas to build up to 18,456 MW of renewable generation.

Oncor was one of several transmission service providers that was formally assigned by the PUC to construct the new transmission lines as a part of CREZ. During the period between 2007-2015, a significant portion of the capital budget for transmission was directed toward new infrastructure which included grid expansion efforts and CREZ projects to name a few. At the time of the last depreciation study, a greater portion of the transmission capital budget was to support the buildout of new infrastructure as opposed to replacing existing infrastructure. The table below provides a comparison in spending over the periods and the types of spending by timeframe when the current depreciation parameters were approved.

Projected Capital Spending 2017

	New Infrastructure			Upgraded Infrastructure	
	History	Forecast		History	Forecast
	2007-2015	2017-2021		2007-2015	2017-2021
Transmission	64%	26%		36%	74%
Distribution	57%	50%		43%	50%
IT	95%	96%		5%	4%
Total Oncor	**63%**	**40%**		**37%**	**60%**
Total Oncor (ex IT)	***61%***	***36%***		***39%***	***64%***

As time has passed, capital spending has shifted to focus on replacement/upgraded infrastructure rounded out by new infrastructure buildout as needed. The forecasted increase in capital infrastructure replacements and upgrades will result in an increase in retirements in both the transmission and distribution FERC accounts outlined in this document. The table below provides these forecasts.

Projected Capital Spending 2022

	New Infrastructure			Upgraded Infrastructure	
	History	Forecast		History	Forecast
	2007-2021	2022-2026		2007-2021	2022-2026
Transmission	49%	34%		51%	66%
Distribution	52%	51%		48%	49%
IT	95%	95%		5%	5%
Total Oncor	**55%**	**44%**		**45%**	**56%**
Total Oncor (ex IT)	***52%***	***41%***		***48%***	***59%***

Historical indications related to retirements and the lives of the various accounts are not considered to be completely representative of future expectations. Some accounts are analyzed by actuarial analysis and others by SPR analysis (which has significantly more years of data). Each account is discussed in detail in the next section.