The information is being provided in electronic format in compliance with RFP General Instruction No. 15. Portions of the information are highly sensitive and will be made available only after execution of a certification to be bound by the draft protective order set forth in Section VII of this Rate Filing Package or a protective order issued in this docket.

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

Testimony Workpapers/Nichols

WP_Nichols – MISO Transmission Cost Estimation Guide for MTEP21.pdf

Testimony Workpapers/Highly Sensitive Confidential/Nichols

Nichols WP_HSC_Index.docx
Nichols Testimony WP – IHS Data Reference.pdf
Nichols Testimony WP – Project Cost Study Workbook.xlsx

Transmission Cost Estimation Guide

For MTEP21

April 27, 2021

Purpose Statement

The MISO transmission planning process focuses on making the benefits of an economically efficient electricity market available to customers by identifying transmission projects that provide access to electricity at the lowest total electric system cost. As a part of this process, MISO identifies essential transmission projects that will improve the reliability and efficiency of energy delivery in the region. Those projects are included in the MISO Transmission Expansion Plan (MTEP), an annual publication that is collaboration between MISO planning staff and stakeholders.

Certain types of projects as identified in MTEP require cost estimates to justify the business case for recommendation to MISO's Board of Directors. MISO provides cost estimates for these certain types of projects in order to evaluate alternatives. MISO's transmission cost estimation guide for MTEP21 describes the approach and cost data that MISO uses in developing its cost estimates. This document's assumptions and cost data are reviewed yearly with stakeholders.

All cost estimate data in this document are in 2021 US Dollars. All applicable taxes are included within the cost subcategories.

Executive Summary

In MISO's planning process, estimated project costs are necessary to evaluate alternatives and recommend projects. The MISO Transmission Expansion Plan (MTEP) may result in a project(s) to be eligible as a Market Efficiency Project (MEP) or in a portfolio of Multi-value Projects (MVP). Eligibility for MEPs and MVPs include a benefit-to-cost ratio requirement - MISO determines the benefits through its planning process, and costs are estimated.

Estimating project costs requires review and coordination throughout the planning process. At the onset of the MCPS, stakeholders submit solution ideas that contain their cost estimate for a potential project. MISO utilizes stakeholders' cost estimate for initial screening of potential projects.

If a potential project passes the initial screening phase, MISO evaluates the costs of a potential project, and provides its planning cost estimate. MISO's planning cost estimates allow all potential projects' costs to be compared to each other using the same cost data and indicative assumptions.

If a potential project continues to show benefits in excess of cost, a more refined scoping cost estimate is created. If the project is not eligible for the Competitive Transmission Process (CTP), the local Transmission Owner will provide the cost estimate and will discuss and review the project scope of work with MISO. If the project is eligible for the Competitive Transmission Process, MISO will provide the scoping cost estimate. MISO's scoping cost estimate is specific for that individual potential project and MISO may adjust any of its cost estimate assumptions and/or any of its unit costs as necessary for that specific potential project. For any facility upgrades included in the project, MISO will discuss its estimate assumptions with the facility owner.

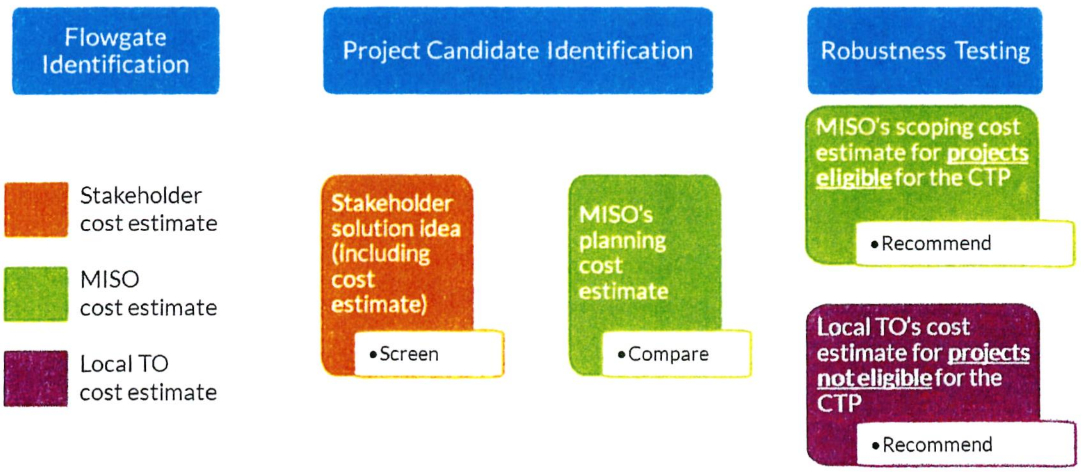


Table of Contents

1. **Total Project Implementation Cost** **4**

2. **Project Costs** **6**

   2.1 Common Cost Categories among all project types 6

   2.2 A/C and HVDC Transmission Lines 8

   2.3 A/C Substations 21

   2.4 HVDC Converter Stations 29

3. **Initial assumptions** **31**

   3.1 A/C and HVDC Transmission Lines 31

   3.2 A/C Substations 34

4. **Exploratory Costs** **37**

   4.1 A/C and HVDC Transmission Lines 37

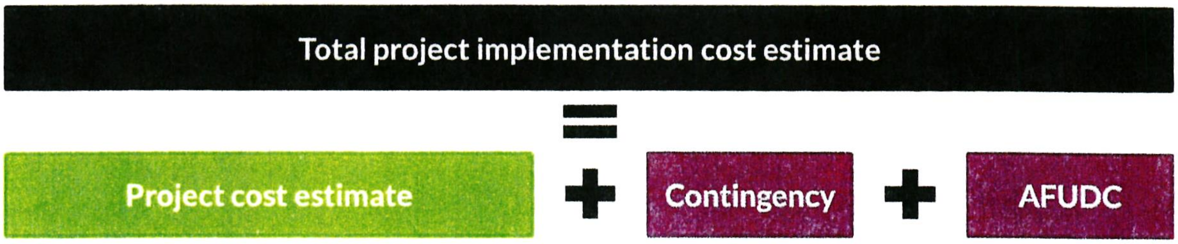
   4.2 A/C Substations 39

   4.3 HVDC Converter Stations 40

5. **Costs Over Time** **41**

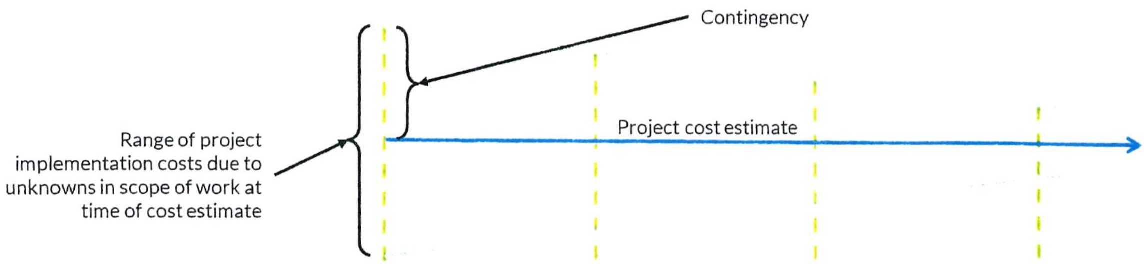
1. Total Project Implementation Cost

Cost estimates that MISO provides are intended to be inclusive of all costs required to implement the project – the total project implementation cost for a potential project. Included in the total project implementation cost estimate is the project cost (as further described in this guide), contingency, and Allowance for Funds Used During Construction (AFUDC).



Contingency

Contingency is a cost adder to account for all the uncertainties/unpredictability and level of scope definition at the time of estimation. As more investigation is completed for a cost estimate (and a project), less contingency is carried as a cost in the cost estimate. MISO has three cost estimates types it provides, with different levels of contingency shown below.



Cost estimate type	Exploratory cost estimate	Planning cost estimate	Scoping cost estimate	Competitive proposal
Level of design investigation	Generic $/mile per State	Desktop analysis	Desktop analysis and local outreach	Field analysis
Contingency adder (% of project cost)	30%	20%	15%	Observed: ~5%

MISO researched industry practices for project cost estimating approaches and has included an instructive reference from the AACE (formerly the Association for the Advancement of Cost Engineering) International©. The cost estimates that MISO provides generally align with the classes in the table below as described:

Class 5 – MISO's exploratory cost estimate

Class 4 – MISO's planning cost estimate

Class 3 – MISO's scoping cost estimate

	Primary Characteristic	*Secondary Characteristic*		
ESTIMATE CLASS	**MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical variation in low and high ranges [a]
Class 5	0% to 2%	Concept screening	Capacity factored, parametric models, judgment, or analogy	L -20% to -50% H. +30% to +100%
Class 4	1% to 15%	Study or feasibility	Equipment factored or parametric models	L· -15% to -30% H: +20% to +50%
Class 3	10% to 40%	Budget authorization or control	Semi-detailed unit costs with assembly level line items	L: -10% to -20% H. +10% to +30%
Class 2	30% to 75%	Control or bid/tender	Detailed unit cost with forced detailed take-off	L: -5% to -15% H: +5% to +20%
Class 1	65% to 100%	Check estimate or bid/tender	Detailed unit cost with detailed take-off	L -3% to -10% H. +3% to +15%

Notes. [a] The state of process technology, availability of applicable reference cost data, and many other risks affect the range markedly The +/- value represents typical percentage variation of actual costs from the cost estimate after application of contingency (typically at a 50% level of confidence) for given scope

AFUDC

AFUDC is a cost adder to account for the cost of debt and/or the cost of equity required to develop and place the project in service. AFUDC is assumed to be the same value for all the cost estimates MISO provides and is assumed to be 7.5% of the sum of the project cost and contingency.

2. Project Costs

Project cost is the cost to construct and install a project. Project cost estimates are categorized into smaller subcategories of cost that are then estimated for each individual project. Some cost category unit costs are common to all project types, while some are unique to the project type. All the unit costs MISO uses in its cost estimates are described below in this section and in general, align with the cost categories MISO uses in its Request for Proposals in its Competitive Transmission Process and all costs include applicable taxes within their subcategory.

2.1 Common Cost Categories among all project types

Project Management

Project implementation scheduling and project management activities and resources for the project. Project management costs are estimated to be 5.5% of the project cost.

Administrative & General Overhead (A&G)

Projected overhead costs that will be allocated to the Project for the period prior to placing the project in service. Administrative & General Overhead (A&G) is estimated to be 1.5% of the project cost.

Engineering, environmental studies, and testing and commissioning

Engineering (including route and site evaluation), environmental studies, and testing and commissioning for the project. Engineering, environmental studies, and testing and commissioning costs are estimated to be 3.0% of the project cost.

Right-of-Way, land acquisition, and regulatory and permitting

Right-of-Way and land acquisition costs are costs to have an easement on the land for projects to be installed, and are typically charged to FERC plant accounts 350 and 359. MISO assumes that new right-of-way is required for all projects except transmission line rebuild projects. MISO has three categories of land costs: pasture, crop, and urban/suburban. Pasture land values are based on USDA published values[1]. MISO utilizes the USDA pasture price as its initial cost for land value as it is a public resource that is updated yearly. MISO assumes that crop land is 3 times more expensive per acre than pasture land and that suburban/urban land is 5 times more expensive than pasture land. Based on its desktop analysis, MISO will determine the land type encountered for each potential project and estimate accordingly. Regulatory and permitting costs include application to state commission boards for approval for construction including public outreach and open houses.

[1] United States Department of Aguriculture Land Values 2020 Summary - https://www.nass.usda.gov/Publications/Todays_Reports/reports/land0820.pdf

All land costs are based upon the acreage of land that the new transmission line would traverse or the substation or HVDC converter station would be sited. The total land affected for a transmission line is the line length multiplied by the right-of-way width of the line. The right-of-way widths that MISO considers are intended to be indicative of right-of-way widths for transmission lines in each voltage class and correlate with the number of structures per mile MISO assumes. Different project conditions (e.g., more or less transmission line structures per mile) in different locations may have a wider or narrower right-of-way width than the indicative value MISO assumes.

Finally, certain states have unique circumstances to be accounted for in their cost estimates. Wisconsin projects involving transmission lines with nominal voltage of 345kV and above have a one-time environmental impact fee in the amount of 5% of the total implementation cost of the transmission line – MISO will include this additional cost in its cost estimate for projects in Wisconsin. Minnesota has a "buy the farm" statute where additional land may be required to be purchased in addition to the right-of-way required for the transmission line – MISO may consider additional land requirements for projects in Minnesota.

Land costs

State – land	Right-of-Way cost per acre			Acquisition cost per acre	Regulatory & permitting cost per acre
	Pasture	Crop	Suburban & Urban		
Arkansas	$2,716	$8,149	$13,581	$12,608	$2,627
Illinois	$3,280	$9,840	$16,400	$12,608	$2,627
Indiana	$2,460	$7,380	$12,300	$12,608	$2,627
Iowa	$2,757	$8,272	$13,786	$12,608	$2,627
Kentucky	$3,126	$9,379	$15,631	$12,608	$2,627
Louisiana	$2,942	$8,825	$14,709	$12,608	$2,627
Michigan	$2,665	$7,995	$13,325	$12,608	$2,627
Minnesota	$1,722	$5,166	$8,610	$12,608	$8,773
Mississippi	$2,511	$7,534	$12,556	$12,608	$2,627
Missouri	$2,050	$6,150	$10,250	$12,608	$2,627
Montana	$697	$2,091	$3,485	$12,608	$2,627
North Dakota	$810	$2,429	$4,049	$12,608	$4,386
South Dakota	$1,076	$3,229	$5,381	$12,608	$3,520
Texas	$1,722	$5,166	$8,610	$12,608	$2,627
Wisconsin	$2,306	$6,919	$11,531	$12,608	$8,773

2.2 A/C and HVDC Transmission Lines

MISO's cost estimation guide contains costs both for alternating current (A/C) transmission lines and for high voltage direct current (HVDC) transmission lines. Both types of transmission lines rely on some similar project costs (i.e., land costs, conductor costs), and some unique costs dependent on the scope of work (i.e., structure costs).

MISO's A/C and HVDC transmission line cost estimates are sub-divided into smaller subcategories as shown below. The smaller subcategories of costs align with MISO's Request for Proposal for Competitive Transmission Projects. MISO's cost estimation guide includes estimated for costs for A/C transmission in voltage classes ranging from 69kV to 500kV, and HVDC transmission in voltage classes from ±250kV to ±600kV.

HVDC transmission has two major components – Transmission Line and Converter station. With the advancement of technology, both components of HVDC transmission have many options and customization for a specific need. For the purposes of creating a cost estimate, MISO will assume a bipole HVDC transmission line with a ground electrode return. Ground electrodes are assumed to be located at each end of the transmission line and connected by a ground electrode line.

Structures

Costs estimated to procure and install structures (inclusive of its required foundation) for new potential transmission line projects. Costs shown below encompass cost subcategories of material, foundations, hardware, and installation typically charged to FERC plant accounts 354 and 355. All structures are designed for the highest applicable NESC loading criteria in the MISO region.

MISO's transmission line cost estimates are comprised of four different structure types:

- Tangent structures are the most commonly used structures where the transmission line alignment is relatively straight and the line angle is between 0° and 2°. Tangent structures support the conductor using a suspension insulator assembly. The suspension insulator assembly consists of insulator and hardware to provide necessary electrical insulation and strength for load transfer. The shieldwire (OPGW) is attached to the shieldwire suspension assembly near the top of the structure.
- Running angle structures are used where the line alignment changes direction and the line angle is between 2° and 45°. Running angle structures support the conductor with a suspension insulator assembly similar to tangent and small angle structures. The shieldwire (OPGW) is attached to a shieldwire suspension assembly near top of structure.
- Non-Angled deadend structures are partial deadend structures and not designed for full terminal loads and the line angle is between 5° to 45°. They are designed to withstand some unbalanced wire tensions in one direction of one or all wires on one face of the structure.

- Angled deadend structures are designed for full terminal loads for all wires and the line angle is between 0° and 90°.

The steel weights and foundation sizes MISO considers for its steel pole and steel tower structure unit costs are intended to be indicative for structures at different voltage classes and are not tied directly to any one structure design for that structure type.

The single and double circuit wood pole structures are included in the guide to address some of the project specific needs involving wood pole construction. The wood pole structure costs that MISO considers for its unit costs are intended to be an indicative value for the structures at different voltage classes and are not tied directly to any one structure design for that structure type.

All structures have the following unit costs as shown in the tables below:

- Material cost includes the cost of design, manufacture (material, labor, equipment) and delivery of the structure to site (laydown yard) and is based on the estimated steel weight.
- Installation cost is the cost to haul, assemble, and install the structure, insulators, and grounding assemblies. This cost includes access to the structure location, and restoration.
- Hardware cost includes material cost for insulator, line hardware and grounding assemblies.
- Foundation cost includes material and installation of the foundations including the cost to procure and install anchor bolts and is based on the estimated foundation size.

Steel structures are assumed to be supported on a concrete drilled pier foundation. Wood pole structures are assumed to be embedded directly in the ground and embedment cost is included in the Installation cost. Drilled pier foundation size for a structure is indicated as concrete volume required per structure in cubic yards.

A/C Transmission – Steel Pole – Single circuit

			Tangent structure				
Voltage class	69kV line	115kV line	138kV line	161kV line	230kV line	345kV line	500kV line
Steel weight (lbs.)	7,000	7,900	8,400	9,300	11,100	22,300	35,100
Foundation size (Cu. Yd)	5.5	6.0	8.0	9.0	13.0	21.0	41.0
Material	$16,072	$18,138	$19,286	$21,353	$25,486	$51,201	$80,590
Installation	$24,108	$27,208	$28,930	$32,029	$38,228	$76,801	$120,577
Hardware	$4,232	$4,937	$5,291	$5,996	$7,053	$9,437	$10,332
Foundation	$7,572	$8,259	$11,013	$12,389	$17,895	$28,908	$56,440
			Running angle structure				
Voltage class	69kV line	115kV line	138kV line	161kV line	230kV line	345kV line	500kV line
Steel weight (lbs.)	11,600	13,000	13,900	15,300	18,300	37,900	59,700
Foundation size (Cu. Yd)	9.0	10.5	13.0	14.0	19.5	30.0	54.5
Material	$26,634	$29,848	$31,914	$35,129	$42,017	$87,018	$137,071
Installation	$39,950	$44,772	$47,872	$52,693	$63,025	$130,528	$205,607
Hardware	$4,232	$4,937	$5,291	$5,996	$7,053	$9,437	$10,332
Foundation	$12,389	$14,455	$17,895	$19,272	$26,844	$41,297	$75,024
			Non-angled deadend structure				
Voltage class	69kV line	115kV line	138kV line	161kV line	230kV line	345kV line	500kV line
Steel weight (lbs.)	14,000	15,800	16,800	18,600	22,200	42,400	66,700
Foundation size (Cu. Yd)	11.0	12.0	15.0	16.5	22.5	33.5	60.0
Material	$32,144	$36,277	$38,573	$42,706	$50,971	$97,350	$153,143
Installation	$48,216	$54,415	$57,859	$64,058	$76,457	$146,026	$229,715
Hardware	$8,345	$9,735	$11,821	$11,821	$13,908	$33,920	$53,358
Foundation	$15,142	$16,519	$22,714	$22,714	$30,973	$46,116	$82,595
			Angled deadend structure				
Voltage class	69kV line	115kV line	138kV line	161kV line	230kV line	345kV line	500kV line
Steel weight (lbs.)	20,400	23,000	24,500	27,100	32,400	48,100	80,700
Foundation size (Cu. Yd)	15.0	16.5	20.0	21.5	29.0	41.5	72.0
Material	$46,838	$52,808	$56,252	$62,222	$74,390	$110,438	$185,287
Installation	$70,258	$79,212	$84,378	$93,332	$111,586	$165,656	$277,931
Hardware	$8,345	$9,735	$10,431	$11,821	$13,908	$33,920	$53,358
Foundation	$20,649	$22,714	$27,532	$29,597	$39,921	$57,128	$99,113

A/C Transmission – Steel Tower – Single circuit

			Tangent structure				
Voltage class	69kV line	115kV line	138kV line	161kV line	230kV line	345kV line	500kV line
Steel weight (lbs.)	6,100	6,900	7,300	8,100	10,100	20,300	27,000
Foundation size (Cu. Yd)	8.5	11.5	13.5	14.5	15.5	19.5	33.5
Material	$11,692	$13,226	$13,992	$15,526	$19,359	$38,910	$51,752
Installation	$17,539	$19,839	$20,989	$23,289	$29,039	$58,366	$77,628
Hardware	$4,232	$4,937	$5,291	$5,996	$7,053	$9,437	$10,332
Foundation	$11,701	$15,831	$18,584	$19,961	$21,337	$26,844	$46,116
			Running angle structure				
Voltage class	69kV line	115kV line	138kV line	161kV line	230kV line	345kV line	500kV line
Steel weight (lbs.)	9,200	10,400	11,000	12,200	15,200	30,500	39,800
Foundation size (Cu. Yd)	16.0	19.0	19.5	22.0	24.5	39.0	72.5
Material	$17,634	$19,934	$21,084	$23,384	$29,135	$58,461	$76,287
Installation	$26,451	$29,901	$31,626	$35,077	$42,702	$87,692	$114,430
Hardware	$4,232	$4,937	$5,291	$5,996	$7,053	$9,437	$10,332
Foundation	$22,025	$26,155	$26,844	$30,285	$33,727	$53,686	$99,302
			Non-angled deadend structure				
Voltage class	69kV line	115kV line	138kV line	161kV line	230kV line	345kV line	500kV line
Steel weight (lbs.)	10,400	11,700	12,400	13,800	17,200	34,500	45,900
Foundation size (Cu. Yd)	21.5	25.0	25.5	28.5	34.0	48.5	96.0
Material	$19,934	$22,426	$23,768	$26,451	$32,968	$66,128	$87,979
Installation	$29,901	$33,639	$35,632	$39,667	$49,452	$99,192	$131,969
Hardware	$8,345	$9,735	$10,431	$11,821	$13,908	$33,920	$53,358
Foundation	$29,597	$34,414	$35,103	$39,233	$46,804	$66,764	$132,151
			Angled deadend structure				
Voltage class	69kV line	115kV line	138kV line	161kV line	230kV line	345kV line	500kV line
Steel weight (lbs.)	13,400	15,200	16,100	17,800	22,200	44,700	59,400
Foundation size (Cu. Yd)	33.5	38.0	39.0	43.0	52.0	90.0	176.0
Material	$25,684	$29,135	$30,860	$34,118	$42,552	$85,679	$113,855
Installation	$38,527	$43,702	$46,290	$51,177	$63,828	$128,519	$170,782
Hardware	$8,345	$9,735	$10,431	$11,821	$13,908	$33,920	$53,358
Foundation	$46,116	$52,310	$53,686	$59,193	$71,582	$123,892	$242,277

A/C Transmission – Steel Pole – Double circuit

			Tangent structure				
Voltage class	69kV line	115kV line	138kV line	161kV line	230kV line	345kV line	500kV line
Steel weight (lbs.)	11,300	12,700	13,500	14,900	18,600	36,000	50,300
Foundation size (Cu. Yd)	8.0	10.0	14.5	17.5	23.0	46.5	78.5
Material	$25,945	$29,159	$30,996	$34,210	$42,706	$82,656	$115,489
Installation	$38,917	$43,739	$46,494	$51,316	$64,058	$123,984	$173,233
Hardware	$8,239	$9,612	$10,298	$11,672	$13,732	$18,478	$20,244
Foundation	$11,013	$13,766	$19,961	$24,091	$31,661	$64,011	$108,062
			Running angle structure				
Voltage class	69kV line	115kV line	138kV line	161kV line	230kV line	345kV line	500kV line
Steel weight (lbs.)	15,000	16,800	17,900	19,700	24,600	47,700	70,400
Foundation size (Cu. Yd)	13.0	15.5	21.5	25.5	32.5	61.0	99.0
Material	$34,440	$38,573	$41,098	$45,231	$56,482	$109,519	$161,638
Installation	$51,660	$57,859	$61,648	$67,847	$84,722	$164,279	$242,458
Hardware	$8,239	$9,612	$10,298	$11,672	$13,732	$18,478	$20,244
Foundation	$17,895	$21,337	$29,597	$35,103	$44,739	$83,971	$136,281
			Non-angled deadend structure				
Voltage class	69kV line	115kV line	138kV line	161kV line	230kV line	345kV line	500kV line
Steel weight (lbs.)	16,700	18,700	19,900	22,000	27,400	54,000	75,500
Foundation size (Cu. Yd)	15.5	18.5	25.0	29.5	37.0	68.5	109.0
Material	$38,343	$42,935	$45,690	$50,512	$62,910	$123,984	$173,348
Installation	$57,515	$64,403	$68,536	$75,768	$94,366	$185,976	$260,022
Hardware	$16,457	$19,201	$20,573	$23,316	$27,430	$67,466	$106,330
Foundation	$21,337	$25,467	$34,414	$40,609	$50,933	$94,296	$150,047
			Angled deadend structure				
Voltage class	69kV line	115kV line	138kV line	161kV line	230kV line	345kV line	500kV line
Steel weight (lbs.)	26,000	29,200	31,100	34,300	42,800	84,600	118,200
Foundation size (Cu. Yd)	20.0	24.0	32.0	37.0	46.0	81.5	127.0
Material	$59,696	$67,043	$71,406	$78,753	$98,269	$194,242	$271,387
Installation	$89,544	$100,565	$107,108	$118,129	$147,403	$291,362	$407,081
Hardware	$16,457	$19,201	$20,573	$23,316	$27,430	$67,466	$106,330
Foundation	$27,532	$33,038	$44,050	$50,933	$63,322	$112,191	$174,825

A/C Transmission – Steel Tower – Double circuit

			Tangent structure				
Voltage class	69kV line	115kV line	138kV line	161kV line	230kV line	345kV line	500kV line
Steel weight (lbs.)	9,200	10,400	11,000	12,200	15,200	36,000	41,900
Foundation size (Cu. Yd)	13.0	17.0	19.5	21.0	22.0	31.5	48.5
Material	$17,634	$19,934	$21,084	$23,384	$29,135	$69,003	$80,312
Installation	$26,451	$29,901	$31,626	$35,077	$43,702	$103,505	$120,468
Hardware	$8,239	$9,612	$10,298	$11,672	$13,732	$18,478	$20,244
Foundation	$17,895	$23,402	$26,844	$28,908	$30,285	$43,363	$66,764
			Running angle structure				
Voltage class	69kV line	115kV line	138kV line	161kV line	230kV line	345kV line	500kV line
Steel weight (lbs.)	13,800	15,600	16,500	18,300	22,800	53,100	62,900
Foundation size (Cu. Yd)	22.5	28.0	34.5	37.5	46.5	59.0	87.5
Material	$26,349	$29,901	$31,626	$35,077	$43,702	$101,779	$120,564
Installation	$39,677	$44,852	$47,440	$52,615	$65,553	$152,670	$180,846
Hardware	$8,239	$9,612	$10,298	$11,672	$13,732	$18,478	$20,244
Foundation	$30,973	$38,544	$47,492	$51,622	$64,011	$81,218	$120,451
			Non-angled deadend structure				
Voltage class	69kV line	115kV line	138kV line	161kV line	230kV line	345kV line	500kV line
Steel weight (lbs.)	16,100	18,200	19,300	21,400	26,600	61,200	71,200
Foundation size (Cu. Yd)	28.5	34.5	43.0	48.5	70.5	86.5	126.5
Material	$30,860	$34,885	$36,993	$41,018	$50,986	$117,305	$136,473
Installation	$46,290	$52,327	$55,490	$61,528	$76,478	$175,958	$204,709
Hardware	$16,457	$19,201	$20,573	$23,316	$27,430	$67,466	$106,330
Foundation	$39,233	$47,492	$59,193	$66,764	$97,049	$119,074	$174,137
			Angled deadend structure				
Voltage class	69kV line	115kV line	138kV line	161kV line	230kV line	345kV line	500kV line
Steel weight (lbs.)	21,200	23,900	25,300	28,100	35,000	79,200	92,200
Foundation size (Cu. Yd)	43.0	50.5	61.5	68.5	99.0	125.0	236.0
Material	$40,635	$45,810	$48,494	$53,861	$67,086	$151,807	$176,724
Installation	$60,953	$68,716	$72,741	$80,792	$100,629	$227,710	$265,087
Hardware	$16,457	$19,201	$20,573	$23,316	$27,430	$67,466	$106,330
Foundation	$59,193	$69,518	$84,660	$94,265	$136,281	$172,072	$324,672

A/C Transmission – Wood Pole – Single circuit

			Tangent structure				
Voltage class	69kV line	115kV line	138kV line	161kV line	230kV line	345kV line	500kV line
Material	$4,518	$8,457	$8,563	$11,399	$12,345	N/A	N/A
Installation	$12,608	$13,133	$14,709	$21,013	$31,519	N/A	N/A
Hardware	$4,413	$4,991	$5,463	$6,041	$7,880	N/A	N/A
			Running angle structure				
Voltage class	69kV line	115kV line	138kV line	161kV line	230kV line	345kV line	500kV line
Material	$7,932	$14,814	$14,971	$19,962	$21,591	N/A	N/A
Installation	$22,063	$23,009	$25,741	$36,772	$55,158	N/A	N/A
Hardware	$7,722	$8,721	$9,561	$10,559	$13,816	N/A	N/A
			Angled deadend structure				
Voltage class	69kV line	115kV line	138kV line	161kV line	230kV line	345kV line	500kV line
Material	$9,035	$16,968	$17,126	$22,799	$24,690	N/A	N/A
Installation	$25,215	$26,266	$29,418	$42,025	$63,038	N/A	N/A
Hardware	$8,825	$9,981	$10,927	$12,083	$15,759	N/A	N/A

A/C Transmission – Wood Pole – Double circuit

			Tangent structure				
Voltage class	69kV line	115kV line	138kV line	161kV line	230kV line	345kV line	500kV line
Material	$7,460	$13,974	N/A	N/A	N/A	N/A	N/A
Installation	$20,802	$21,695	N/A	N/A	N/A	N/A	N/A
Hardware	$7,302	$8,247	N/A	N/A	N/A	N/A	N/A
			Running angle structure				
Voltage class	69kV line	115kV line	138kV line	161kV line	230kV line	345kV line	500kV line
Material	$13,080	$24,427	N/A	N/A	N/A	N/A	N/A
Installation	$36,404	$37,980	N/A	N/A	N/A	N/A	N/A
Hardware	$12,765	$14,394	N/A	N/A	N/A	N/A	N/A
			Angled deadend structure				
Voltage class	69kV line	115kV line	138kV line	161kV line	230kV line	345kV line	500kV line
Material	$14,919	$27,999	N/A	N/A	N/A	N/A	N/A
Installation	$41,650	$43,338	N/A	N/A	N/A	N/A	N/A
Hardware	$14,858	$16,495	N/A	N/A	N/A	N/A	N/A

HVDC Transmission – Steel Pole – Single circuit

		Tangent structure		
Voltage class	± 250kV line	± 400kV line	± 500kV line	± 600kV line
Steel weight (lbs.)	14,773	19,943	21,938	26,325
Foundation size (Cu. Yd)	17.0	23.0	26.0	31.0
Material	$33,990	$45,886	$50,475	$60,570
Installation	$50,986	$68,830	$75,713	$90,856
Hardware	$4,587	$5,843	$6,355	$6,663
Foundation	$23,448	$31,655	$35,268	$42,322
		Running angle structure		
Voltage class	± 250kV line	± 400kV line	± 500kV line	± 600kV line
Steel weight (lbs.)	25,126	33,920	37,313	44,775
Foundation size (Cu. Yd)	23.0	31.0	34.0	41.0
Material	$57,812	$78,047	$85,851	$103,022
Installation	$86,718	$117,069	$128,777	$154,532
Hardware	$5,734	$7,303	$7,944	$8,328
Foundation	$31,570	$42,618	$46,880	$56,257
		Non-angled deadend structure		
Voltage class	± 250kV line	± 400kV line	± 500kV line	± 600kV line
Steel weight (lbs.)	28,072	37,898	41,688	50,025
Foundation size (Cu. Yd)	25.0	34.0	38.0	45.0
Material	$64,590	$87,198	$95,917	$115,101
Installation	$96,886	$130,796	$143,876	$172,651
Hardware	$9,046	$21,909	$23,831	$24,984
Foundation	$34,756	$46,920	$51,612	$61,935
		Angled deadend structure		
Voltage class	± 250kV line	± 400kV line	± 500kV line	± 600kV line
Steel weight (lbs.)	33,965	45,852	50,438	60,525
Foundation size (Cu. Yd)	30.0	41.0	45.0	54.0
Material	$78,148	$105,500	$116,051	$139,260
Installation	$117,222	$158,250	$174,075	$208,890
Hardware	$9,046	$21,909	$23,831	$24,984
Foundation	$41,706	$56,304	$61,935	$74,322

HVDC Transmission – Steel Tower – Single circuit

	Tangent structure			
Voltage class	± 250kV line	± 400kV line	± 500kV line	± 600kV line
Steel weight (lbs.)	10,227	15,341	16,875	20,250
Foundation size (Cu. Yd)	13.0	19.0	21.0	25.0
Material	$19,556	$29,333	$32,267	$38,720
Installation	$29,333	$44,001	$48,401	$58,082
Hardware	$4,587	$5,843	$6,355	$6,663
Foundation	$17,465	$26,197	$28,817	$34,580
	Running angle structure			
Voltage class	± 250kV line	± 400kV line	± 500kV line	± 600kV line
Steel weight (lbs.)	16,751	22,614	24,875	29,850
Foundation size (Cu. Yd)	31.0	41.0	45.0	54.0
Material	$32,030	$43,241	$47,564	$57,077
Installation	$48,045	$64,861	$71,346	$85,616
Hardware	$5,734	$7,303	$7,944	$8,328
Foundation	$41,996	$56,695	$62,364	$74,837
	Non-angled deadend structure			
Voltage class	± 250kV line	± 400kV line	± 500kV line	± 600kV line
Steel weight (lbs.)	19,318	26,080	28,688	34,425
Foundation size (Cu. Yd)	40.0	55.0	60.0	72.0
Material	$36,969	$49,867	$54,855	$65,826
Installation	$55,480	$74,801	$82,282	$98,738
Hardware	$9,046	$21,909	$23,831	$24,984
Foundation	$55,609	$75,072	$82,579	$99,095
	Angled deadend structure			
Voltage class	± 250kV line	± 400kV line	± 500kV line	± 600kV line
Steel weight (lbs.)	25,000	33,750	37,125	44,550
Foundation size (Cu. Yd)	74.0	100.0	110.0	132.0
Material	$47,804	$64,535	$70,988	$85,186
Installation	$71,705	$96,802	$106,482	$127,779
Hardware	$9,046	$21,909	$23,831	$24,984
Foundation	$101,950	$137,632	$151,396	$181,674

Project specific environmental circumstances of an individual project may lead to additional installation costs. Where a new transmission line traverses a forested area, wetland area, or mountainous terrain, the following additional costs are considered.

Additional structure installation costs

Voltage class	69kV – 600kV line
Forested clearing cost (per acre)	$5,305
Wetland (per acre)	Matting & construction difficulties: $61,921 Wetland mitigation credits: $49,672
Mountainous terrain (per acre)	$6,897

Removal cost of existing transmission line and/or substation involves complete removal or retirement of existing transmission line or substation equipment. The removal costs include all plant, tools, equipment, machinery, skill, supervision and labor.

Transmission line removal/retirement $/mile

Voltage class	69kV line	115kV line	138kV line	161kV line	230kV line	345kV line	500kV line
Wood pole – single circuit	$194,366	$226,192	$236,391	$249,524	$278,416	N/A	N/A
Wood pole – double circuit	$315,188	$362,466	N/A	N/A	N/A	N/A	N/A

Conductor

Costs estimated to procure and install conductor required for transmission line projects typically charged to FERC plant account 356. Conductor costs are based upon the conductor selected and the length of the transmission line. MISO assumes conductor length adder of 4% for sag and wastage per conductor. Conductor type and size are based on economic planning model considerations for the required ampacity and based on Business Practice Manual 029 to assign appropriate conductor type. See initial assumptions to see MISO's indicative conductor selection and ratings for different voltage classes.

Potential projects may involve re-conductoring or upgrading existing conductor size to allow more power transfer by increasing ampacity of the existing circuit. In providing cost estimates for re-conductoring project scope, MISO assumes that the existing structures including foundations, insulators and hardware are adequate to support the new conductor size and configuration and discusses this assumption with the Transmission Owner. The costs of new conductor and installation are considered for the estimate of the retrofit projects.

MISO primarily considers ACSR (Aluminum Conductor Steel Reinforce), ACSS (Aluminum Conductor Steel Supported) conductor types in its cost estimates. Where required, MISO would consider the cost for T2 to be equivalent to two conductors of that size to the same cost when creating its cost estimate.

Conductors have the following unit costs as shown in the tables below:

- Material cost is the cost of manufacturing and deliver conductor to site (laydown yard).
- Installation cost is the cost to haul conductor reels, install, and sag and clip conductor on transmission structures.
- Accessories are the sleeves, spacers, and dampers material and installation cost required for a transmission line.

Conductor costs (<1000 kcmil)

Conductor	Material cost per 1000 feet		Installation cost per 1000 feet	Accessories cost per 1000 feet
	ACSR	ACSS		
266.8 kcmil "Waxwing"	$566	$552	$770	$245
266.8 kcmil "Partridge"	$683	$706	$954	$245
336.4 kcmil "Merlin"	$604	$673	$875	$245
336.4 kcmil "Linnet"	$696	$806	$1,028	$245
336.4 kcmil "Oriole"	$868	$894	$1,210	$245
397.5 kcmil "Chickadee"	$745	$784	$1,050	$245
397.5 kcmil "Ibis"	$895	$955	$1,269	$245
397.5 kcmil "Lark"	$884	$1,060	$1,329	$245
477 kcmil "Pelican"	$873	$960	$1,257	$245
477 kcmil "Flicker"	$838	$1,004	$1,261	$245
477 kcmil "Hawk"	$1,043	$1,115	$1,481	$245
477 kcmil "Hen"	$1,162	$1,192	$1,617	$245
556.5 kcmil "Osprey"	$1,049	$1,060	$1,449	$245
556.5 kcmil "Parakeet"	$1,230	$1,225	$1,689	$245
556.5 kcmil "Dove"	$1,163	$1,281	$1,676	$245
636 kcmil "Kingbird"	$1,013	$1,192	$1,509	$245
636 kcmil "Rook"	$1,148	$1,379	$1,729	$245
636 kcmil "Grosbeak"	$1,315	$1,435	$1,887	$245
666.6 kcmil "Flamingo"	$1,356	$1,590	$1,994	$245
795 kcmil "Coot"	$1,343	$1,490	$1,942	$245
795 kcmil "Tern"	$1,269	$1,512	$1,903	$245
795 kcmil "Cuckoo"	$1,413	$1,700	$2,129	$245
795 kcmil "Condor"	$1,468	$1,700	$2,169	$245
795 kcmil "Drake"	$1,590	$1,599	$2,192	$245
900 kcmil "Canary"	$1,800	$1,755	$2,445	$245
954 kcmil "Rail"	$1,677	$1,706	$2,325	$245
954 kcmil "Cardinal"	$1,836	$1,892	$2,561	$245

Conductor costs (>1000 kcmil)

Conductor	Material cost per 1000 feet		Installation cost per 1000 feet	Accessories cost per 1000 feet
	ACSR	ACSS		
1033.5 kcmil "Ortolan"	$1,839	$2,274	$2,811	$245
1033.5 kcmil "Curlew"	$2,028	$1,921	$2,718	$245
1113 kcmil "Bluejay"	$1,954	$2,440	$3,002	$245
1192.5 kcmil "Bunting"	$1,822	$2,042	$2,648	$245
1272 kcmil "Bittern"	$2,111	$2,185	$2,951	$245
1272 kcmil "Pheasant"	$2,307	$2,527	$3,315	$245
1351.5 kcmil "Dipper"	$2,283	$2,770	$3,456	$245
1351.5 kcmil "Martin"	$2,829	$2,462	$3,651	$245
1431 kcmil "Bobolink"	$2,588	$2,881	$3,749	$245
1590 kcmil "Lapwing"	$2,669	$2,826	$3,772	$245
1590 kcmil "Falcon"	$3,150	$3,153	$4,333	$245
1780 kcmil "Chukar"	$3,432	$3,676	$4,878	$245
2156 kcmil "Bluebird"	$4,043	$4,492	$5,851	$245
2167 kcmil "Kiwi"	$3,661	$5,354	$6,134	$245
2312 kcmil "Thrasher"	$4,194	$4,801	$6,162	$245
2515 kcmil "Joree"	$4,458	$5,034	$6,504	$245

OPGW and shieldwire

Costs estimated to procure and install Optical Groundwire (OPGW) and/or shieldwire required for transmission line projects typically charged to FERC plant account 356. Unless otherwise specified by the solution idea, MISO assumes one OPGW and one steel shieldwire per transmission circuit. MISO assumes conductor and shieldwire length adder of 4% for sag and wastage per conductor, OPGW, and shieldwire. Optical Groundwire (OPGW) and shieldwire are installed at the top of structures to protect the conductors below from direct lightning strikes and includes fiber optic cable. OPGW and shield wires have the following unit costs as shown in the tables below:

- Material cost is the cost of manufacturing and delivery of the OPGW or shieldwire to site (laydown yard).
- Installation cost is the cost to haul the OPGW and shieldwire reels, install, and sag and clip conductor on transmission structures.

OPGW and shieldwire costs

Wire	Material cost per 1000 feet	Installation cost per 1000 feet
Shieldwire	$551	$828
OPGW	$2,495	$3,742

2.3 A/C Substations

Substation cost estimates are sub-divided in to the cost categories as shown in the table below. MISO provides cost estimates for both substation upgrades and for new substation sites. For planning cost estimates, MISO assumes size (acreage) requirements and equipment quantities based on general assumptions for the project area – see section for initial assumptions in this guide. Both the size of the substation facilities and the equipment quantities are dependent upon the voltage class of the facility and the number of new line/transformer positions being considered. For scoping cost estimates that are upgrades of existing substations, MISO discusses its scope of work assumptions with the existing substation owner. If the substation is a new facility, MISO follows requirements in its Business Practice Manual 029 (BPM-029).

Site work

Costs estimated to prepare the land for a substation including clearing, grading, grounding and physical security. Depending on the terrain encountered for a specific substation site (e.g., forested area, or wetlands), additional costs may be required. Where specialized site components are required (e.g. specialized gates, access protection, import/export of soil) MISO will add those costs to its cost estimate and will call them out separately.

Site work unit costs

Voltage class	69kV – 500kV
Level ground with light vegetation (per acre)	$357,095
Forested land (per acre)	+$5,305
Wetland (per acre)	+$61,921 for matting and construction difficulties +$49,672 for wetland mitigation credits

Access Road

Access roads are estimated based on the length of the road. Access roads allow entry to the substation site from the nearest drivable public road. For the access road into a substation, MISO uses Google Earth to estimate the length of the access road required. Access road costs are estimated to be $538,125 per mile.

Electrical Equipment Material, Electrical Equipment Installation, Steel Structure Material, Steel Structure Installation, and Substation Foundation

Costs estimated to procure and install material and steel structures. Costs are divided into the following subcategories:

- Material cost is the cost to procure and deliver electrical equipment materials to site (laydown yard).
- Installation cost is the cost to assemble and place on foundation or steel structure.
- As applicable, Jumpers, conduit, wiring, and grounding cost includes material and installation of the electrical jumpers and fittings to connect to adjacent electrical equipment, above grade conduit, landing control cables on terminal block in equipment, and the above grade ground grid connection.
- Steel structure material cost includes the cost of design, manufacture (material, labor, equipment) and delivery of the structure to site (laydown yard) and is based on the estimated steel weight.
- Steel structure installation cost is the cost to place the steel stand on the foundation.
- Foundation cost includes material and installation of the foundations including the cost to procure and install anchor bolts and is based on the estimated foundation size.

Circuit breaker unit costs

Voltage class	69kV	115kV	138kV	161kV	230kV	345kV	500kV
Foundation size (Cu. Yd)	3.6	4.5	5.3	6.7	8.0	8.8	19.8
Material cost	$42,025	$52,531	$55,158	$57,784	$99,809	$330,422	$434,959
Installation cost	$7,880	$8,405	$8,931	$9,456	$10,506	$15,759	$21,013
Jumpers, conduit, wiring, grounding	$8,405	$9,456	$10,506	$12,608	$15,759	$21,013	$26,266
Foundation cost	$4,956	$6,195	$7,296	$9,223	$11,013	$12,113	$27,256

Disconnect switch (3-phase) unit costs

Voltage class	69kV	115kV	138kV	161kV	230kV	345kV	500kV
Foundation size (Cu. Yd)	3.4	4.2	5.2	6.5	7.8	8.0	18.0
Steel stand weight (pounds)	1500	1750	2000	2500	3500	4000	5000
Material cost	$10,506	$13,133	$15,759	$18,386	$21,013	$36,772	$52,531
Installation cost	$6,304	$7,354	$8,405	$9,456	$10,506	$15,759	$21,013
Jumpers, and grounding	$4,203	$4,728	$5,253	$6,304	$7,880	$10,506	$13,133
Steel stand material cost	$3,444	$4,018	$4,592	$5,740	$8,036	$9,184	$11,480
Steel stand installation cost	$3,961	$4,621	$5,281	$6,601	$9,241	$10,599	$13,202
Foundation cost	$4,680	$5,782	$7,159	$8,948	$10,737	$11,013	$24,778

Bus support, bus, and fittings (3-phase) unit costs

Voltage class	69kV	115kV	138kV	161kV	230kV	345kV	500kV
Foundation size (Cu. Yd)	3.1	3.9	4.8	6.0	7.2	9.6	14.4
Steel stand weight (pounds)	1000	1250	1500	1750	2000	3000	4500
Material cost	$6,041	$7,565	$8,721	$9,167	$9,613	$11,373	$13,107
Installation cost	$7,250	$9,077	$10,464	$11,000	$11,536	$13,648	$15,728
Steel stand material cost	$2,296	$2,870	$3,444	$4,018	$4,592	$6,888	$10,332
Steel stand installation cost	$2,640	$3,301	$3,961	$4,621	$5,281	$7,921	$11,882
Foundation cost	$4,267	$5,369	$6,607	$8,259	$9,912	$13,215	$19,822

Voltage Transformer (set of 3) unit costs

Voltage class	69kV	115kV	138kV	161kV	230kV	345kV	500kV
Foundation size (Cu. Yd)	1.8	2.3	2.7	3.4	4.0	8.0	12.1
Steel stand weight (pounds)	1250	1350	1425	1500	1750	2000	2500
Material cost	$21,013	$23,640	$26,266	$28,893	$36,772	$44,126	$84,050
Installation cost	$2,101	$2,364	$2,627	$2,889	$3,152	$4,203	$5,253
Jumpers, conduit, wiring, grounding	$6,304	$7,092	$7,880	$9,456	$11,819	$15,759	$19,696
Steel stand material cost	$2,870	$3,100	$3,272	$3,444	$4,018	$4,592	$5,740
Steel stand installation cost	$3,301	$3,565	$3,763	$3,961	$4,621	$5,281	$6,601
Foundation cost	$2,477	$3,166	$3,717	$4,680	$5,506	$11,013	$16,656

Current Transformer (set of 3) unit costs

Voltage class	69kV	115kV	138kV	161kV	230kV	345kV	500kV
Foundation size (Cu. Yd)	1.8	2.3	2.7	3.4	4.0	8.0	12.1
Steel stand weight (pounds)	1250	1350	1425	1500	1750	2000	2500
Material cost	$64,850	$81,056	$110,421	$121,452	$132,537	$220,868	$386,525
Installation cost	$2,101	$2,364	$2,627	$2,889	$3,152	$4,203	$5,253
Jumpers, conduit, wiring, grounding	$6,304	$7,092	$7,880	$9,456	$11,819	$15,759	$19,696
Steel stand material cost	$2,870	$3,100	$3,272	$3,444	$4,018	$4,592	$5,740
Steel stand installation cost	$3,301	$3,565	$3,763	$3,961	$4,621	$5,281	$6,601
Foundation cost	$2,477	$3,166	$3,717	$4,680	$5,506	$11,013	$16,656

Deadend structure unit cost is the cost associated with one angled deadend structure. The unit cost utilized for a deadend structure installed in a substation is same unit cost is used for transmission line estimates.

Removal cost of existing substation equipment includes all plant, tools, equipment, machinery, skill, supervision and labor. For any substation equipment that is required to be removed, MISO will utilize its installation cost for that item and consider it equivalent as the cost of removal.

Power transformer unit cost is the cost associated with one power transformer. Power transformer cost varies based on the low side voltage winding and high side voltage winding. Unit cost includes all material, shipping, foundation, and installation costs with that transformer. For a scoping cost estimate, MISO will discuss power transformer pricing with vendors.

Power transformer ($/MVA)

Voltage class	69kV	115kV	138kV	161kV	230kV	345kV	500kV
69kV	$4,961	$4,039	$4,469	$4,705	$5,217	$6,406	$8,262
115kV	$4,039	$5,494	$4,469	$4,705	$5,217	$6,089	$7,472
138kV	$4,469	$4,469	$6,089	$4,961	$5,217	$6,089	$7,472
161kV	$4,705	$4,705	$4,961	$6,745	$5,494	$6,406	$7,862
230kV	$5,217	$5,217	$5,217	$5,494	$7,472	$6,406	$7,862
345kV	$6,406	$6,089	$6,089	$6,406	$6,406	$9,102	$8,0262
500kV	$8,262	$7,472	$7,472	$7,862	$7,862	$8,262	$12,198

Grid supporting devices unit costs are the costs associated to procure and install devices to support the grid. Unit costs include all material, shipping, foundation, and installation costs. Additional substation upgrades to add a bus position for interconnection of grid supporting devices are not included in the costs shown in the table below and will be included in a cost estimate if needed. Certain grid supporting devices are nominally rated less than transmission voltage (i.e., less than 69kV). In order to connect those devices to the transmission system, they must be stepped up to a transmission voltage. Energy Storage costs are focused on transmission applications which historically tend to be smaller with less economies of scale than large wholesale installations. For its cost guide for MTEP21, MISO referenced Lazard's Levelized Cost of Storage Analysis Version 6.0[2] for energy storage costs specifically with a transmission application. MISO will research energy storage costs annually in order to stay up-to-date with market costs which historically have declined year-over-year. For a scoping cost estimate, MISO will discuss grid supporting device pricing with vendors.

[2] Lazard's Levelized Cost of Storage Analysis – Version 6.0. https://www.lazard.com/media/451566/lazards-levelized-cost-of-storage-version-60-vf2.pdf

Grid supporting devices unit costs

Voltage class	69kV	115kV	138kV	161kV	230kV	345kV	500kV
Reactor ($/MVAr)	$14,262	$14,262,	$14,262	$14,262	$14,262	$14,262	$14,262
Capacitor bank ($/MVAr)	$10,506	$10,506	$10,506	$10,506	$10,506	$10,506	$10,506
Static VAr Compensator ($/MVAr)	$101,043	$101,043	$101,043	$101,043	$101,043	$101,043	$101,043
STATCOM ($/MVAr)	$200,000	$200,000	$200,000	$200,000	$200,000	$200,000	$200,000
Synchronous condenser ($/MVAr)	$150,000/MVAr + $150/kw (step-up to 69kV)						
Energy storage (lithium ion)	Battery system: $300/kwh + Inverter: $80/kw + $150/kw (step-up to 69kV)						

Control Enclosure and communication system

Cost estimated for one control enclosure of approximately 500 square feet. Material and installation cost are the cost to procure and deliver one control enclosure to site (laydown yard), offload and placement of the control enclosure on the foundation and wiring of the AC/DC systems to field equipment. Control enclosure includes AC panels, DC panels, cable tray, and all other typical components. Relay panels are considered separately. Battery and battery charger costs is the material and installation cost for the batteries in the control enclosure and their associated battery charger. Communication equipment costs are the cost to account for communication equipment placed inside the substation (e.g. fiber patch panel, remote terminal unit, human machine interface). Station service power is the cost to provide station service power to the control enclosure. Foundation size is the amount of cubic yards of concrete required for the foundation. Foundation cost is the combination of the material and installation cost for the foundation and is based on the estimated foundation size.

Control enclosure unit costs

Voltage class	69kV	115kV	138kV	161kV	230kV	345kV	500kV
Foundation size (Cu. Yd)	18.0	18.0	18.0	18.0	18.0	18.0	18.0
Material and installation cost	$315,188	$315,188	$315,188	$315,188	$315,188	$315,188	$315,188
Battery and battery charger	$105,063	$105,063	$105,063	$105,063	$105,063	$105,063	$105,063
Communication equipment	$105,063	$105,063	$105,063	$105,063	$105,063	$157,594	$157,594
Station service power	$115,569	$115,569	$115,569	$115,569	$115,569	$136,581	$136,581
Foundation cost	$24,778	$24,778	$24,778	$24,778	$24,778	$24,778	$24,778

Relay Panels

Costs estimated for one relay panel per voltage class. Material cost is the cost to procure and deliver one relay panel to site (laydown yard). Procurement of the relay panel includes all the relays and devices in the panel, and all the internal wiring for the devices in each individual relay panel. Installation cost includes: placement of relay panel in control enclosure; wiring from field equipment; inter-panel wiring to other relay panels inside control enclosure.

Relay panel unit costs

Voltage class	69kV	115kV	138kV	161kV	230kV	345kV	500kV
Material cost	$19,699	$24,558	$30,731	$34,671	$38,348	$51,218	$64,088
Installation cost	$39,399	$49,117	$61,462	$69,341	$76,696	$102,436	$128,176

Control Cable, Conduit, and Cable Trench

Control cable unit cost is the cost associated with 1000 feet of control cable. Material cost is the cost to procure and deliver 1000 feet of control cable to site (laydown yard). Installation cost includes placing and pulling control cable in conduit and/or cable trench and bringing the control cable to its end point where it will be landed. Final wiring of landing on terminal blocks is included in other unit costs.

Control cable unit costs

Voltage class	69kV	115kV	138kV	161kV	230kV	345kV	500kV
Material cost per 1000 feet	$3,152	$3,152	$3,152	$3,152	$3,152	$4,203	$4,203
Installation cost per 1000 feet	$5,253	$5,253	$5,253	$5,253	$5,253	$5,253	$5,253

Conduit unit cost is the cost associated with 1000 feet of conduit. Material cost is the cost to procure and deliver 1000 feet of conduit to site (laydown yard). Included in the material cost is the conduit along with applicable fittings and connectors. Installation cost includes excavation, placement of conduit, and utilizing all applicable fittings and connectors.

Conduit unit costs

Voltage class	69kV	115kV	138kV	161kV	230kV	345kV	500kV
Material cost per 1000 feet	$3,152	$3,152	$3,152	$3,152	$3,152	$3,152	$3,152
Installation cost per 1000 feet	$42,025	$42,025	$42,025	$42,025	$42,025	$42,025	$42,025

Cable trench unit cost is the cost associated with 1 foot of cable trench inclusive of lid/cover. Material cost is the cost to procure and deliver 1 foot of cable trench to site (laydown yard). Installation cost includes excavation, and placement of cable trench. Placement of control cables in cable trench is included in the control cable installation cost.

Cable trench unit costs

Voltage class	69kV	115kV	138kV	161kV	230kV	345kV	500kV
Material cost per 1 foot	$52	$52	$52	$52	$52	$52	$52
Installation cost per 1 foot	$210	$210	$210	$210	$210	$210	$210

2.4 HVDC Converter Stations

Converter stations are required at each endpoint of an HVDC transmission line in order to interconnection with the A/C transmission system. MISO includes in its guide two converter station design types - line-commutated thyristor valve technology (LCC) and Voltage-Source transistor technology (VSC).

In addition to only a converter station, there would also be A/C substation equipment needed to interconnect. Typical interconnection voltages would be 230kV A/C for a ±250kV HVDC transmission line, 345kV A/C for a ±400kV HVDC transmission line, and 500kV A/C for a ±500kV and ±600kV HVDC transmission line. For the purposes of creating a cost estimate, in the tables below, MISO assumes its exploratory costs for a new 4-position, breaker-and-a-half substation for the A/C substation costs connected with a new converter station.

At each converter station, MISO assumes a ground electrode is installed. Historically, HVDC electrodes have been installed to provide a low resistance path during both monopolar and bipolar operations, using earth as a conductive medium. Although this option of return path in HVDC is less expensive, there are environmental and regulatory implications. For the purpose of the cost estimate, MISO assumes that those concerns are permitted by respective authorities and addressed by the developer.

The ground electrode is a structure with a conductor, or a group of conductors embedded in the soil directly or surrounded by conductive medium providing an electric path to ground. The electrodes are generally located relatively close to the converter stations. MISO's unit cost of a ground electrode includes engineering study, permitting, material, labor and land. In addition to the ground electrode, there is also the ground electrode line which is an electrical connection between conversions and ground electrode. The cost of overhead ground electrode line includes supporting structures, foundations, conductor material and labor. MISO assumes 20 miles of ground electrode line at each of the HVDC transmission line.

Line Commutated Converter (LCC) Stations are composed of thyristor valves and are located indoors to provide safe, clean and controlled operating environment. The cost of bipolar converter station valve hall includes land and land acquisition, building, DC switching station equipment including DC filters, converter transformer, insulation, control devices and services. LCC stations require A/C filters which are included in the converter station costs. Reactive power compensation is assumed to be a Static Var Compensator, which the costs are shown in section 3.2.

Converter Station
Line Commutated Converter (LCC) – one end

Voltage class	± 250kV line	± 400kV line	± 500kV line	± 600kV line
Power Transfer	500MW	1500MW	2000MW	2400MW
Assumed Reactive Power Need	167MVAR	500MVAR	667MVAR	800MVAR
Ground electrode line length	20 miles	20 miles	20 miles	20 miles
Valve hall	$30.8M	$112.8M	$153.8M	$189.6M
A/C filters	$3.1M	$11.3M	$15.4M	$19.0M
Reactive power	$16.9M	$50.5M	$67.4M	$80.9M
A/C Substation	$11.0M	$16.1M	$23.4M	$23.4M
Ground electrode	$2.8M	$3.7M	$3.8M	$4.0M
Ground electrode line	$4.1M	$10.3M	$12.3M	$15.4M

Voltage Source Converter (VSC) Stations are composed of IGBT valves and are located indoors to provide safe, clean and controlled operating environment. The cost of bipolar converter station valve hall includes land and land acquisition, building, DC switching station equipment including DC filters, converter transformer, insulation, control devices and services. It is assumed that VSC converter stations do not require any additional reactive power support and they can inherently provide power with a 0.95 leading to a 0.95 lagging power factor.

Converter Station
Voltage Source Converter (VSC) – one end

Voltage class	± 250kV line	± 400kV line	± 500kV line	± 600kV line
Power Transfer	500MW	1500MW	2000MW	2400MW
Ground electrode line length	20 miles	20 miles	20 miles	20 miles
Valve hall	$73.8.M	$235.8M	$317.8M	$389.5M
A/C Substation	$11.0M	$16.1M	$23.4M	$23.4M
Ground electrode	$2.8M	$3.7M	$3.8M	$4.0M
Ground electrode line	$4.1M	$10.3M	$12.3M	$15.4M

3. Initial assumptions

To create a cost estimate, MISO must make initial assumptions about the scopes of work for potential projects. This section lists out all the initial assumptions MISO makes. As more information becomes known, scope of work assumptions is refined. The assumptions are not an indication of how a potential project should be built, but merely an instrument to provide a cost estimate.

3.1 A/C and HVDC Transmission Lines

Line length

The line length for a transmission line is a consideration for determining its cost estimate for a potential project. For exploratory and planning cost estimates, the line length is determined by the straight-line distance between the two substations plus a 30%-line length adder. This 30%-line length adder is intended to account for routing constraints that will be determined upon further development of the potential transmission line project. For scoping cost estimates, the line length is determined by a MISO-created proxy route based upon a desktop study. For new potential projects, MISO considers new right-of-way. For retrofit/re-conductor projects, MISO assumes that the existing right-of-way is adequate. MISO does not share its assumed proxy route information with stakeholders, as the route could be perceived as a MISO endorsed/preferred route. MISO's proxy route is merely an instrument to support the MISO's transmission line cost estimate. MISO utilizes Google Earth to determine route length, land types, and terrain types encountered.

Right-of-Way width

The right-of-way widths that MISO considers are intended to be indicative of right-of-way widths for transmission lines in each voltage class. Different project conditions in different locations may have a wider or narrower right-of-way width than the indicative value MISO assumes. MISO's assumptions for right-of-way width are in the tables below:

Right-of-Way width

A/C Transmission (single and double circuit)							
Voltage class	69kV line	115kV line	138kV line	161kV line	230kV line	345kV line	500kV line
Feet	80	90	95	100	125	175	200

HVDC transmission (single circuit)				
Voltage class	± 250kV line	± 400kV line	± 500kV line	± 600kV line
Feet	130	180	200	215

Structures per mile

In order to create a cost estimate for transmission lines, MISO makes indicative assumptions about the quantity of structures per mile required. The indicative assumptions are not connected to any specific project. For A/C Transmission, MISO assumes steel pole structure type for 69kV – 345kV, and steel tower structure type for 500kV. For HVDC, MISO assumes steel pole structure type for 250kV, and steel tower structure for 400kV – 600kV. The quantity of structures per mile that MISO assumes for its cost estimates are shown in the tables below:

Structures per mile – A/C transmission
Steel tower & steel pole (single circuit / double circuit)

Voltage class	69kV line	115kV line	138kV line	161kV line	230kV line	345kV line	500kV line
Tangent structures	9 / 9.5	8.5 / 9	8 / 8.5	7 / 7.5	5 / 7	4.5 / 6	3.0 / 5
Running angle structures	1 / 1	1 / 1	1 / 1	1 / 1	1 / 1	1 / 1	1 / 1
Non-angled deadend structures	0.25 / 0.25	0.25 / 0.25	0.25 / 0.25	0.25 / 0.25	0.25 / 0.25	0.25 / 0.25	0.25 / 0.25
Angled deadend structures	0.25 / 0.25	0.25 / 0.25	0.25 / 0.25	0.25 / 0.25	0.25 / 0.25	0.25 / 0.25	0.25 / 0.25

Structures per mile – A/C transmission
Wood pole (single circuit / double circuit)

Voltage class	69kV line	115kV line	138kV line	161kV line	230kV line	345kV line	500kV line
Tangent structures	15.5 / 18.5	13.5 / 16.5	13.5 / N/A	10.5 / N/A	7.5 / N/A	N/A / N/A	N/A / N/A
Running angle structures	1 / 1	1 / 1	1 / N/A	1 / N/A	1 / N/A	N/A / N/A	N/A / N/A
Angled deadend structures	0.5 / 0.5	0.5 / 0.5	0.5 / N/A	0.5 / N/A	0.5 / N/A	N/A / N/A	N/A / N/A

Structures per mile – HVDC transmission
Steel tower & steel pole (single circuit)

Voltage class	± 250kV line	± 400kV line	± 500kV line	± 600kV line
Tangent structures	4.5	4.0	3.5	3.0
Running angle structures	0.5	0.5	0.5	0.5
Non-angled structures	0.25	0.25	0.25	0.25
Angled structures	0.25	0.25	0.25	0.25

Conductor selection

Conductor selection for MISO's exploratory cost estimates are shown in the table below. The conductor selected is intended to be typical for a circuit in the voltage class. Specific solution ideas may necessitate different conductors than as shown below.

Conductor selection per circuit – A/C Transmission

Voltage class	69kV line	115kV line	138kV line	161kV line	230kV line	345kV line	500kV line
Conductor size	477kcmil	795kcmil	795kcmil	795kcmil	795kcmil	795kcmil	954kcmil
Conductor type	ACSS	ACSS	ACSS	ACSS	ACSS	ACSS	ACSR
Conductor quantity	1	1	1	1	1	2	3
Amp rating	1175	1650	1650	1650	1650	3000	3000
Power rating (MVA)	140	329	394	460	657	1792	2598

Conductor selection per circuit – HVDC Transmission

Voltage class	± 250kV line	± 400kV line	± 500kV line	± 600kV line
Conductor size	1590kcmil	1590kcmil	1590kcmil	1590kcmil
Conductor type	ACSR	ACSR	ACSR	ACSR
Conductor quantity per pole	1	2	2	2
Power transfer	500MW	1500MW	2000MW	2400MW

Land and Terrain type

A significant cost driver for transmission line projects is the land and terrain types encountered. MISO recognizes that different States present different environments to be accounted for in its cost estimates. In order to provide exploratory cost estimates on a State-by-State basis, MISO makes different assumptions on the land and terrain encountered unique to each State in the MISO footprint. The indicative assumptions in the tables below are not tied to any specific project and are intended for the sole purpose of providing MISO's exploratory cost estimate.

Land and terrain type per State

State	Land type (pasture, crop, and suburban/urban land sum to 100% per State)			Terrain type (level ground, forested, and wetland terrain sum to 100% per State)		
	Pasture land	Crop land	Suburban/ Urban	Level ground	Forested	Wetland
Arkansas	25%	65%	10%	40%	55%	5%
Illinois	25%	65%	10%	55%	40%	5%
Indiana	25%	65%	10%	80%	15%	5%
Iowa	10%	80%	10%	80%	15%	5%
Kentucky	25%	65%	10%	65%	25%	10%
Louisiana	25%	65%	10%	55%	25%	20%
Michigan	25%	65%	10%	50%	40%	10%
Minnesota	10%	80%	10%	70%	25%	5%
Mississippi	25%	65%	10%	55%	25%	20%
Missouri	25%	65%	10%	40%	55%	5%
Montana	70%	20%	10%	85%	10%	5%
North Dakota	70%	20%	10%	90%	5%	5%
South Dakota	50%	40%	10%	90%	5%	5%
Texas	65%	25%	10%	50%	30%	20%
Wisconsin	25%	65%	10%	70%	25%	5%

3.2 A/C Substations

In order to provide exploratory cost estimates for substations, MISO makes indicative assumptions for the quantity of equipment required for substation upgrades and for new substations. The indicative assumptions for substation equipment tables below are not tied to any specific project and are intended for the sole purpose of providing MISO's exploratory cost estimate.

Initial assumptions – bus ratings

Voltage class	69kV	115kV	138kV	161kV	230kV	345kV	500kV
Amp rating	1200	2000	2000	2000	2000	3000	3000
Power rating (MVA)	143	398	478	558	797	1792	2598

Substation upgrade – add 1 position (ring / breaker-and-a-half / double-breaker bus)

Scope of work	69kV	115kV	138kV	161kV	230kV	345kV	500kV
Land required (acre)	0.4 / 0.5 / 0.6	0.5 / 0.6 / 0.7	0.5 / 0.6 / 0.8	0.6 / 0.7 / 0.8	0.6 / 0.8 / 0.9	0.8 / 0.9 / 1.1	1.3 / 1.6 / 1.9
Access road (mile)	0 / 0 / 0	0 / 0 / 0	0 / 0 / 0	0 / 0 / 0	0 / 0 / 0	0 / 0 / 0	0 / 0 / 0
Circuit breakers (each)	1 / 2 / 2	1 / 2 / 2	1 / 2 / 2	1 / 2 / 2	1 / 2 / 2	1 / 2 / 2	1 / 2 / 2
Disconnect switches (each)	2 / 4 / 4	2 / 4 / 4	2 / 4 / 4	2 / 4 / 4	2 / 4 / 4	2 / 4 / 4	2 / 4 / 4
Voltage transformers (set of 3)	1 / 1 / 2	1 / 1 / 2	1 / 1 / 2	1 / 1 / 2	1 / 1 / 2	1 / 1 / 2	1 / 1 / 2
Bus support, bus, and fittings (3-phase)	4 / 4 / 6	4 / 4 / 6	4 / 4 / 6	4 / 4 / 6	4 / 4 / 6	6 / 6 / 8	8 / 8 / 10
Deadend structure	1 / 1 / 1	1 / 1 / 1	1 / 1 / 1	1 / 1 / 1	1 / 1 / 1	1 / 1 / 1	1 / 1 / 1
Control enclosure	0 / 0 / 0	0 / 0 / 0	0 / 0 / 0	0 / 0 / 0	0 / 0 / 0	0 / 0 / 0	0 / 0 / 0
Relay panel(s)	1 / 2 / 2	1 / 2 / 2	1 / 2 / 2	1 / 2 / 2	1 / 2 / 2	1 / 2 / 2	1 / 2 / 2
Cable trench (foot), conduit (10 feet), control cable (100 feet)	50 / 70 / 90	50 / 70 / 100	50 / 80 / 100	50 / 80 / 110	60 / 80 / 110	60 / 90 / 120	70 / 110 / 140

Substation upgrade – add 2 positions (ring / breaker-and-a-half / double-breaker bus)

Scope of work	69kV	115kV	138kV	161kV	230kV	345kV	500kV
Land required (acre)	0.8 / 1.0 / 1.2	0.9 / 1.1 / 1.4	1.0 / 1.3 / 1.5	1.1 / 1.4 / 1.7	1.2 / 1.5 / 1.8	1.5 / 1.9 / 2.3	2.5 / 3.1 / 3.8
Access road (mile)	0 / 0 / 0	0 / 0 / 0	0 / 0 / 0	0 / 0 / 0	0 / 0 / 0	0 / 0 / 0	0 / 0 / 0
Circuit breakers (each)	2 / 3 / 4	2 / 3 / 4	2 / 3 / 4	2 / 3 / 4	2 / 3 / 4	2 / 3 / 4	2 / 3 / 4
Disconnect switches (each)	4 / 6 / 8	4 / 6 / 8	4 / 6 / 8	4 / 6 / 8	4 / 6 / 8	4 / 6 / 8	4 / 6 / 8
Voltage transformers (set of 3)	2 / 2 / 2	2 / 2 / 2	2 / 2 / 2	2 / 2 / 2	2 / 2 / 2	2 / 2 / 2	2 / 2 / 2
Bus support, bus, and fittings (3-phase)	8 / 8 / 12	8 / 8 / 12	8 / 8 / 12	8 / 8 / 12	8 / 8 / 12	12 / 12 / 16	16 / 16 / 20
Deadend structure	2 / 2 / 2	2 / 2 / 2	2 / 2 / 2	2 / 2 / 2	2 / 2 / 2	2 / 2 / 2	2 / 2 / 2
Control enclosure	0 / 0 / 0	0 / 0 / 0	0 / 0 / 0	0 / 0 / 0	0 / 0 / 0	0 / 0 / 0	0 / 0 / 0
Relay panel(s)	2 / 3 / 4	2 / 3 / 4	2 / 3 / 4	2 / 3 / 4	2 / 3 / 4	2 / 3 / 4	2 / 3 / 4
Cable trench (foot), conduit (10 feet), control cable (100 feet)	90/ 135/ 180	95/ 143/ 190	100/ 150/ 200	105/ 158/ 210	110/ 165/ 220	120/ 180/ 240	140/ 210/ 280

New substation – 4 positions (ring / breaker-and-a-half / double-breaker bus)

Scope of work	69kV	115kV	138kV	161kV	230kV	345kV	500kV
Land required (acre)	1.6 / 2.0 / 2.4	1.8 / 2.3 / 2.7	2.0 / 2.5 / 3.0	2.2 / 2.8 / 3.3	2.4 / 3.0 / 3.6	3.0 / 3.8 / 4.5	5.0 / 6.3 / 7.5
Access road (mile)	1 / 1 / 1	1 / 1 / 1	1 / 1 / 1	1 / 1 / 1	1 / 1 / 1	1 / 1 / 1	1 / 1 / 1
Circuit breakers (each)	4 / 6 / 8	4 / 6 / 8	4 / 6 / 8	4 / 6 / 8	4 / 6 / 8	4 / 6 / 8	4 / 6 / 8
Disconnect switches (each)	8 / 12 / 16	8 / 12 / 16	8 / 12 / 16	8 / 12 / 16	8 / 12 / 16	8 / 12 / 16	8 / 12 / 16
Voltage transformers (set of 3)	4 / 6 / 6	4 / 6 / 6	4 / 6 / 6	4 / 6 / 6	4 / 6 / 6	4 / 6 / 6	4 / 6 / 6
Bus support, bus, and fittings (3-phase)	12 / 14 / 16	12 / 14 / 16	12 / 14 / 16	12 / 14 / 16	12 / 14 / 16	14 / 16 / 20	20 / 24 / 32
Deadend structure	4 / 4 / 4	4 / 4 / 4	4 / 4 / 4	4 / 4 / 4	4 / 4 / 4	4 / 4 / 4	4 / 4 / 4
Control enclosure	1 / 1 / 1	1 / 1 / 1	1 / 1 / 1	1 / 1 / 1	1 / 1 / 1	1 / 1 / 1	1 / 1 / 1
Relay panel(s)	6 / 8 / 10	6 / 8 / 10	6 / 8 / 10	6 / 8 / 10	6 / 8 / 10	6 / 8 / 10	6 / 8 / 10
Cable trench (foot), conduit (10 feet), control cable (100 feet)	180 / 270 / 360	190 / 290 / 380	200 / 300 / 400	210 / 320 / 420	220 / 330 / 440	240 / 360 / 480	280 / 420 / 560

New substation – 6 positions (ring / breaker-and-a-half / double-breaker bus)

Scope of work	69kV	115kV	138kV	161kV	230kV	345kV	500kV
Land required (acre)	2.0 / 2.5 / 3.0	2.3 / 2.8 / 3.4	2.5 / 3.1 / 3.8	2.8 / 3.4 / 4.1	3.0 / 3.8 / 4.5	3.8 / 4.7 / 5.6	6.3 / 7.8 / 9.4
Access road (mile)	1 / 1 / 1	1 / 1 / 1	1 / 1 / 1	1 / 1 / 1	1 / 1 / 1	1 / 1 / 1	1 / 1 / 1
Circuit breakers	6 / 9 / 12	6 / 9 / 12	6 / 9 / 12	6 / 9 / 12	6 / 9 / 12	6 / 9 / 12	6 / 9 / 12
Disconnect switches	12 / 18 / 24	12 / 18 / 24	12 / 18 / 24	12 / 18 / 24	12 / 18 / 24	12 / 18 / 24	12 / 18 / 24
Voltage transformers (set of 3)	6 / 8 / 8	6 / 8 / 8	6 / 8 / 8	6 / 8 / 8	6 / 8 / 8	6 / 8 / 8	6 / 8 / 8
Bus support, bus, and fittings (3-phase)	14 / 16 / 20	14 / 16 / 20	14 / 16 / 20	14 / 16 / 20	14 / 16 / 20	16 / 20 / 24	24 / 32 / 40
Deadend structure	6 / 6 / 6	6 / 6 / 6	6 / 6 / 6	6 / 6 / 6	6 / 6 / 6	6 / 6 / 6	6 / 6 / 6
Control enclosure	1 / 1 / 1	1 / 1 / 1	1 / 1 / 1	1 / 1 / 1	1 / 1 / 1	1 / 1 / 1	1 / 1 / 1
Relay panel(s)	8 / 11 / 14	8 / 11 / 14	8 / 11 / 14	8 / 11 / 14	8 / 11 / 14	8 / 11 / 14	8 / 11 / 14
Cable trench (foot), conduit (10 feet), control cable (100 feet)	270 / 410 / 540	290 / 430 / 570	300 / 450 / 600	320 / 470 / 630	330 / 500 / 600	360 / 540 / 720	420 / 630 / 840

4. Exploratory Costs

In the planning process it can be helpful to explore many different project ideas quickly to assess broadly if they would be viable. MISO provides exploratory cost estimates which are intended for projects with low levels of scope definition. Exploratory cost estimates are high-level cost estimates which MISO does not recommend using for any solution idea in the regular planning cycle due to the breadth of the assumptions used to derive the unit costs and lower level of granularity regarding specific project components. The exploratory cost estimates provided below are based on the assumptions and cost data as shown in this guide. Before a potential project is recommended for approval to MISO's Board of Directors, MISO completes a thorough scoping cost estimate, all the details of which are shared with stakeholders for their review and comment. In the tables below, MISO is providing its exploratory cost estimate in a $/mile cost as defined by its voltage class and by the State where the potential project would be developed.

4.1 A/C and HVDC Transmission Lines

Exploratory cost estimate – A/C Transmission
New single circuit transmission line $/mile

Location – State	69kV line	115kV line	138kV line	161kV line	230kV line	345kV line	500kV line
Arkansas	$1.5M	$1.7M	$1.8M	$1.8M	$1.9M	$3.1M	$3.3M
Illinois	$1.6M	$1.7M	$1.8M	$1.9M	$2.0M	$3.2M	$3.3M
Indiana	$1.5M	$1.7M	$1.7M	$1.8M	$1.9M	$3.0M	$3.2M
Iowa	$1.5M	$1.7M	$1.8M	$1.8M	$1.9M	$3.1M	$3.3M
Kentucky	$1.6M	$1.8M	$1.9M	$1.9M	$2.1M	$3.3M	$3.5M
Louisiana	$1.8M	$2.0M	$2.1M	$2.1M	$2.3M	$3.6M	$3.9M
Michigan	$1.6M	$1.8M	$1.9M	$1.9M	$2.1M	$3.3M	$3.5M
Minnesota	$1.6M	$1.7M	$1.8M	$1.9M	$2.0M	$3.2M	$3.4M
Mississippi	$1.8M	$1.9M	$2.0M	$2.1M	$2.3M	$3.6M	$3.8M
Missouri	$1.5M	$1.7M	$1.8M	$1.8M	$1.9M	$3.1M	$3.2M
Montana	$1.4M	$1.6M	$1.6M	$1.7M	$1.7M	$2.8M	$3.0M
North Dakota	$1.4M	$1.6M	$1.7M	$1.7M	$1.8M	$2.9M	$3.0M
South Dakota	$1.4M	$1.6M	$1.7M	$1.7M	$1.8M	$2.9M	$3.0M
Texas	$1.7M	$1.9M	$2.0M	$2.0M	$2.2M	$3.5M	$3.7M
Wisconsin	$1.6M	$1.8M	$1.8M	$1.9M	$2.0M	$3.2M	$3.4M

Includes contingency (30%) and AFUDC (7.5%)

Exploratory cost estimate – A/C Transmission
New double circuit transmission line $/mile

Location – State	69kV line	115kV line	138kV line	161kV line	230kV line	345kV line	500kV line
Arkansas	$2.2M	$2.5M	$2.6M	$2.7M	$3.2M	$5.2M	$5.4M
Illinois	$2.2M	$2.5M	$2.6M	$2.7M	$3.2M	$5.2M	$5.4M
Indiana	$2.2M	$2.4M	$2.6M	$2.6M	$3.1M	$5.1M	$5.3M
Iowa	$2.2M	$2.5M	$2.6M	$2.7M	$3.1M	$5.1M	$5.4M
Kentucky	$2.3M	$2.5M	$2.7M	$2.8M	$3.3M	$5.3M	$5.6M
Louisiana	$2.4M	$2.7M	$2.9M	$3.0M	$3.5M	$5.7M	$6.0M
Michigan	$2.3M	$2.5M	$2.7M	$2.8M	$3.3M	$5.3M	$5.6M
Minnesota	$2.2M	$2.5M	$2.6M	$2.7M	$3.2M	$5.2M	$5.5M
Mississippi	$2.4M	$2.7M	$2.9M	$2.9M	$3.5M	$5.6M	$5.9M
Missouri	$2.2M	$2.4M	$2.6M	$2.6M	$3.1M	$5.1M	$5.3M
Montana	$2.1M	$2.3M	$2.5M	$2.5M	$3.0M	$4.9M	$5.1M
North Dakota	$2.1M	$2.3M	$2.5M	$2.5M	$3.0M	$4.9M	$5.1M
South Dakota	$2.1M	$2.3M	$2.5M	$2.5M	$3.0M	$4.9M	$5.2M
Texas	$2.4M	$2.7M	$2.8M	$2.9M	$3.4M	$5.5M	$5.8M
Wisconsin	$2.2M	$2.5M	$2.7M	$2.7M	$3.2M	$5.3M	$5.5M

Includes contingency (30%) and AFUDC (7.5%)

Exploratory cost estimate – A/C Transmission
Rebuild and reconductor transmission line $/mile

Location – All States	69kV line	115kV line	138kV line	161kV line	230kV line	345kV line	500kV line
Rebuild – single circuit	$1.4M	$1.5M	$1.6M	$1.6M	$1.7M	N/A	N/A
Rebuild – double circuit	$2.0M	$2.3M	N/A	N/A	N/A	N/A	N/A
Reconductor – per circuit	$0.30M	$0.34M	$0.34M	$0.35M	$0.33M	$0.54M	$0.65M

Includes contingency (30%) and AFUDC (7.5%)

Exploratory cost estimate – HVDC Transmission
New bipole transmission line $/mile

Location – State	250kV line	400kV line	500kV line	600kV line
Arkansas	$2.0M	$2.4M	$2.5M	$2.7M
Illinois	$2.1M	$2.4M	$2.5M	$2.7M
Indiana	$2.0M	$2.3M	$2.4M	$2.5M
Iowa	$2.1M	$2.3M	$2.5M	$2.6M
Kentucky	$2.2M	$2.5M	$2.7M	$2.9M
Louisiana	$2.4M	$2.9M	$3.1M	$3.3M
Michigan	$2.2M	$2.5M	$2.7M	$2.8M
Minnesota	$2.1M	$2.4M	$2.6M	$2.7M
Mississippi	$2.4M	$2.8M	$3.0M	$3.2M
Missouri	$2.0M	$2.3M	$2.4M	$2.6M
Montana	$1.8M	$2.1M	$2.2M	$2.3M
North Dakota	$1.9M	$2.1M	$2.2M	$2.4M
South Dakota	$1.9M	$2.1M	$2.2M	$2.4M
Texas	$2.3M	$2.7M	$2.9M	$3.1M
Wisconsin	$2.1M	$2.5M	$2.6M	$2.8M

Includes contingency (30%) and AFUDC (7.5%)

4.2 A/C Substations

In the planning process it can be helpful to explore many different project ideas quickly to assess broadly if they would be viable. MISO provides exploratory cost estimates which are intended for projects with low levels of scope definition. Exploratory cost estimates are high-level cost estimates which MISO does not recommend using for any solution idea in the regular planning cycle due to the breadth of the assumptions used to derive the unit costs and lower level of granularity regarding specific project components. The exploratory cost estimates provided below are based on the assumptions and cost data as shown in this guide. Before a potential project is recommended for approval to MISO's Board of Directors, MISO completes a thorough scoping cost estimate, all the details of which are shared with stakeholders for their review and comment.

Substations have a variety of layouts and arrangements. MISO's exploratory cost estimates for substations are intended to capture the most common substation arrangements that are estimated in MISO's planning process. The arrangements selected for the exploratory indicative cost estimates in this section are not an all-inclusive list for substation arrangements. Exploratory cost estimates are provided for both substation upgrades and new substations. Bus ratings per voltage class are included in the indicative assumptions and are aligned line ratings assumed by MISO for its transmission line project cost estimates.

Exploratory cost estimate – substation upgrade

Scope of work	69kV	115kV	138kV	161kV	230kV	345kV	500kV
Add 1 position (ring bus)	$1.1M	$1.3M	$1.5M	$1.6M	$1.9M	$3.0M	$4.7M
Add 1 position (breaker-and-a-half bus)	$1.5M	$1.8M	$2.0M	$2.3M	$2.7M	$4.4M	$6.5M
Add 1 position (double-breaker bus)	$1.7M	$2.0M	$2.3M	$2.5M	$3.0M	$4.7M	$7.0M
Add 2 positions (ring bus)	$2.3M	$2.6M	$2.9M	$3.3M	$3.8M	$6.0M	$9.3M
Add 2 positions (breaker-and-a-half bus)	$2.8M	$3.2M	$3.7M	$4.1M	$4.8M	$7.6M	$11.5M
Add 2 positions (double-breaker bus)	$3.5M	$4.1M	$4.6M	$5.1M	$6.0M	$9.5M	$14.1M

Includes contingency (30%) and AFUDC (7.5%)

Exploratory cost estimate – new substation

Scope of work	69kV	115kV	138kV	161kV	230kV	345kV	500kV
4 positions (ring bus)	$6.6M	$7.3M	$8.0M	$8.7M	$9.8M	$14.0M	$20.2M
4 positions (breaker-and-a-half bus)	$7.9M	$8.8M	$9.7M	$10.6M	$12.1M	$17.5M	$25.4M
4 positions (double-breaker bus)	$9.1M	$10.2M	$11.3M	$12.3M	$14.1M	$21.0M	$30.6M
6 positions (ring bus)	$8.4M	$9.3M	$10.3M	$11.2M	$12.8M	$18.7M	$27.3M
6 positions (breaker-and-a-half bus)	$10.1M	$11.4M	$12.6M	$13.7M	$15.9M	$23.8M	$34.8M
6 positions (double-breaker bus)	$11.8M	$13.4M	$14.9M	$16.3M	$18.9M	$28.6M	$41.9M

Incudes contingency (30%) and AFUDC (7.5%)

4.3 HVDC Converter Stations

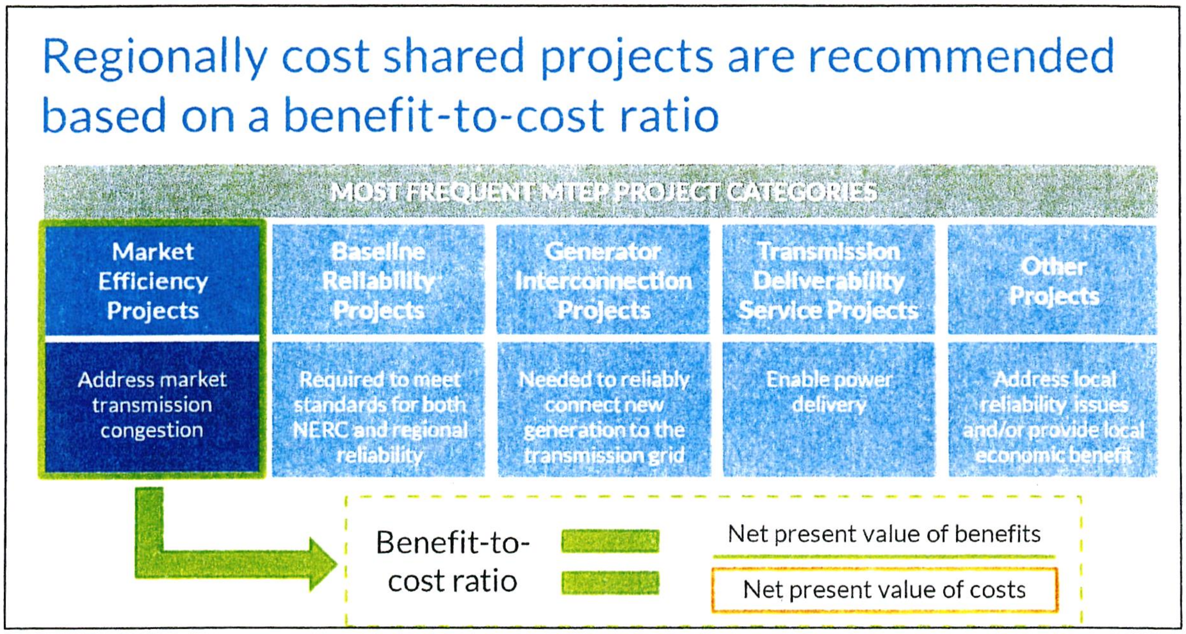
Exploratory cost estimate – HVDC Transmission Converter Station (one end)

Location – All States	250kV line	400kV line	500kV line	600kV line
Line Commutated Converter	$106M	$315M	$424M	$510M
Voltage Source Converter	$140M	$409M	$549M	$664M

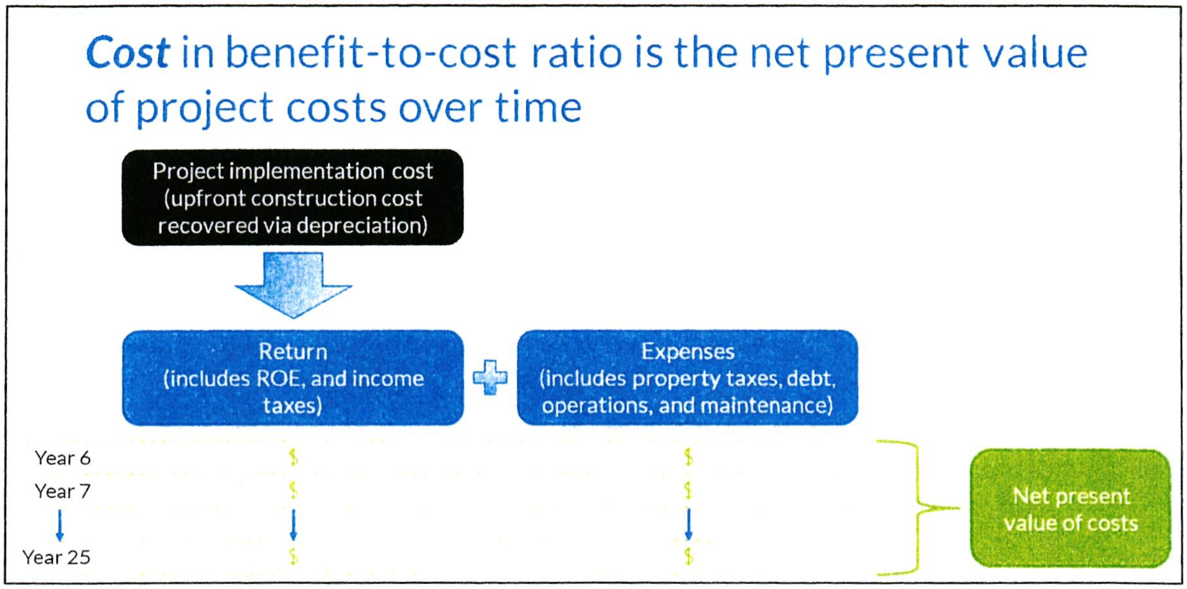
Includes contingency (30%) and AFUDC (7.5%)

5. Costs Over Time

In MISO's yearly MTEP, certain types of projects may be identified to be recommended to our Board that are justified on a benefit-to-cost ratio requirement. In order to evaluate alternatives in the planning process, MISO estimates the net present value of costs over time of differing solution ideas that may also be differing technology types (e.g., energy storage project vs. transmission line project).



In order to estimate costs over time, MISO estimates depreciation costs, expense factors, and return factors for transmission projects. Expense factors and return factors vary by State to account for state-level differences in taxes (e.g., income taxes and property taxes).



In its estimate of costs over time, MISO makes assumptions about the following cost inputs:

Year #	Present Value Discount Rate	Gross Plant Project Cost ISD Yr.$ (PI)	Net Plant Project Cost ISD Yr.$ (PI)	Annual Depreciation Factor	Return Factor subject to decrease in net plant	Expense Factor	Annual Cost to be Recovered	Net Present Value Cost

Year(s)

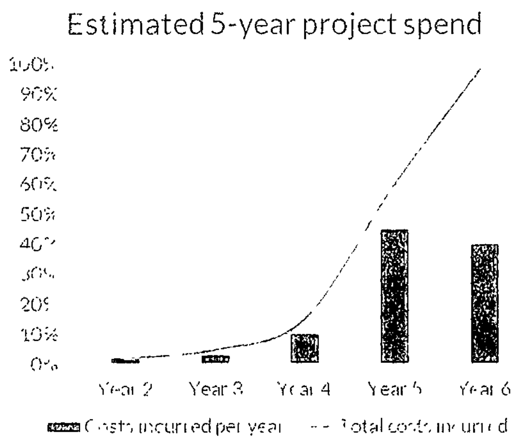
MISO defines the Project Costs to be used in the benefit-to-cost ratio as the present value of the annual revenue requirements projected for the first 20 years of the project's life (Attachment FF Section II.C.7). An example of the years used in the calculation for a project that will take 5 years to construct is that years 6 through 25 will be the first 20 annual revenue requirement years. The present value cost calculation is over the same period for which the project benefits are determined.

Present Value Discount Rate

Calculated by MISO annually as the after-tax weighted average cost of capital of the Transmission owners that make up the Transmission Provider Transmission System. MISO's estimated costs over time will use the same discount rate as used to determine benefits.

Gross Plant (nominal cost estimate)

The nominal cost to construct the project is also the amount used for the annual revenue requirements calculation. The present year project cost estimate is converted to nominal cost by factoring a construction spend per year and an annual inflation rate of 2.5%. The graph and table below show how an example $100M project is expressed as a nominal cost estimate at an assumed 5-year project development time span.



Example: Project cost = $100M, Contingency = $20M, AFUDC = $9M
Present year project implementation cost = $129M
Nominal project implementation cost = $146.6M

Estimated 5-year project spend

Year	2*	3	4	5	6	Subtotal
Costs incurred per year	2%	3%	10%	45%	40%	100%
Present year project implementation cost	$2.6M	$3.9M	$12.9M	$58.0M	$51.6M	$129.0M
Convert to nominal dollars at 2.5% inflation rate. Nominal cost = present year cost * (1 + inflation rate) ^ (project year)						
Nominal project implementation cost	$2.7M	$4.2M	$14.2M	$65.7M	$59.8M	$146.6M

Net Plant and Annual Depreciation Factor

The Gross plant less depreciation based on a 40-Year asset life, which is 2.5% depreciation per year.

Return Factor and Expense Factor (by State)

The Return Factor accounts for the cost of equity and income taxes. The return factor changes annually as it is a factor of net gross plant which is reduced annually as a result of depreciation. The Expense Factor accounts for property taxes, the cost of debt, and operations and maintenance. For energy storage installations, in addition to the Expense Factor below, MISO will assume replacement of the inverters every 10 years after project is in service, and replacement of the battery system every 15 years after the project is in service Both factors are based on Attachment O's and GG's provided by MISO Transmission Owners and vary by State as shown in the table below·

Expense Factor and Return Factor (by State)

State	Expense Factor	Return Factor (adjusted for the first year of depreciation)
Arkansas	2.73%	8.28%
Illinois	3.40%	8.47%
Indiana	2.91%	8.41%
Iowa	3.16%	8.63%
Kentucky	2.84%	8.25%
Louisiana	2.54%	8.37%
Michigan	3.34%	8.25%
Minnesota	3.03%	8.49%
Mississippi	2.73%	8.18%
Missouri	2.95%	8.26%
Montana	2.90%	8.29%
North Dakota	3.23%	8.20%
South Dakota	3.15%	7.86%
Texas	3.45%	7.86%
Wisconsin	3.45%	8.37%

Annual cost to be recovered

Calculation of the estimated annual revenue requirement which is the sum of the depreciation factor, the expense factor, and the return factor multiplied by the Gross Transmission Plant value.

Net Present Value Cost

Appling the discount rate to the first 20 years of the annual revenue requirement results in the NPV cost to be used in the benefit-to-cost ratio. Net Present Value Cost is calculated per year by multiplying the annual cost to be recovered by the Present Value Discount Rate for their respective years.

Example

For example, if we were estimating the costs over time for a project in Arkansas, that had a nominal cost estimate of $172.0M, and we use a discount rate of 7.00%, based on the approach we described above, the net present value of cost over the first 20 years of in-service life would be $174.1M as shown in the table below:

Year #	Present Value Discount Rate	Gross Plant Project Cost ISD Yr.$ (PI)	Net Plant Project Cost ISD Yr.$ (PI)	Annual Depreciation Factor	Return Factor subject to decrease in net plant	Expense Factor	Annual Cost to be Recovered	Net Present Value Cost
MTEP Year	1.000							
1	0.935							
2	0.873							
3	0.816							
4	0.763							
5	0.713				8.28%			
6	0.666	$195,567,182	$190,678,003	2.50%	8.07%	2.73%	$26,016,045	$17,335,590
7	0.623	$195,567,182	$185,788,823	2.50%	7.86%	2.73%	$25,611,281	$15,949,419
8	0.582	$195,567,182	$180,899,643	2.50%	7.66%	2.73%	$25,206,516	$14,670,422
9	0.544	$195,567,182	$176,010,464	2.50%	7.45%	2.73%	$24,801,752	$13,490,510
10	0.508	$195,567,182	$171,121,284	2.50%	7.24%	2.73%	$24,396,987	$12,402,191
11	0.475	$195,567,182	$166,232,105	2.50%	7.04%	2.73%	$23,992,223	$11,398,532
12	0.444	$195,567,182	$161,342,925	2.50%	6.83%	2.73%	$23,587,458	$10,473,114
13	0.415	$195,567,182	$156,453,746	2.50%	6.62%	2.73%	$23,182,694	$9,619,994
14	0.388	$195,567,182	$151,564,566	2.50%	6.42%	2.73%	$22,777,929	$8,833,674
15	0.362	$195,567,182	$146,675,387	2.50%	6.21%	2.73%	$22,373,165	$8,109,065
16	0.339	$195,567,182	$141,786,207	2.50%	6.00%	2.73%	$21,968,400	$7,441,457
17	0.317	$195,567,182	$136,897,027	2.50%	5.80%	2.73%	$21,563,636	$6,826,495
18	0.296	$195,567,182	$132,007,848	2.50%	5.59%	2.73%	$21,158,871	$6,260,147
19	0.277	$195,567,182	$127,118,668	2.50%	5.38%	2.73%	$20,754,107	$5,738,683
20	0.258	$195,567,182	$122,229,489	2.50%	5.17%	2.73%	$20,349,342	$5,258,657
21	0.242	$195,567,182	$117,340,309	2.50%	4.97%	2.73%	$19,944,578	$4,816,877
22	0.226	$195,567,182	$112,451,130	2.50%	4.76%	2.73%	$19,539,813	$4,410,393
23	0.211	$195,567,182	$107,561,950	2.50%	4.55%	2.73%	$19,135,049	$4,036,479
24	0.197	$195,567,182	$102,672,771	2.50%	4.35%	2.73%	$18,730,284	$3,692,612
25	0.184	$195,567,182	$97,783,591	2.50%	4.14%	2.73%	$18,325,520	$3,376,462
								$174,140,771

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

I. POSITION AND QUALIFICATIONS 2
II. PURPOSE OF DIRECT TESTIMONY 2
III. T&D OPERATIONS 3
  A. T&D Operations Organization 3
  B. Oncor O&M Costs Associated with T&D Operations 4
IV. TRANSMISSION GRID OPERATIONS 5
V. MAJOR INITIATIVES SINCE DECEMBER 31, 2016 9
  A. TMS Replacement 9
  B. Telecommunications Refresh Program ("TRP") Project 12
  C. New Backup Control Center 15
  D. Sharyland Operations Transition 17
  E. Operation Services Provided to Oncor NTU 20
  F. Operation Services Provided to Sharyland 22
VI. OPERATIONS DURING WINTER STORM URI 23
  A. Pre-storm Planning and Preparation 23
  B. Winter Storm Timeline 25
  C. Assessment of Oncor's Performance 29
  D. Lessons Learned and Areas for Improvement 32
VII. SUMMARY AND CONCLUSION 35
AFFIDAVIT 37
EXHIBITS 38

Exhibit CMM-1 T&D Operations Organizational Chart
Exhibit CMM-2 T&D Operations Organizational Functions
Exhibit CMM-3 Winter Storm Uri Operational Timeline

DIRECT TESTIMONY OF COLLIN M. MARTIN

I. POSITION AND QUALIFICATIONS

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

A. My name is Collin M. Martin. I am employed by Oncor Electric Delivery Company LLC ("Oncor" or "Company"). My business address is 2233-B Mountain Creek Parkway, Dallas, Texas 75211. I hold the position of Senior Director, Transmission Grid Operations ("TGO").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I hold a Bachelor of Science and a Master of Engineering in electrical engineering from Texas A&M University and am a licensed Professional Engineer in Texas. I have been employed by Oncor for 19 years in roles spanning many aspects of engineering, operations, and support functions, including System Protection, Transmission Operations, TGO, Asset Management, Program Management, and Transmission Engineering.

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

A. No, I have not.

II. PURPOSE OF DIRECT TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my direct testimony is to:

- introduce Oncor's Transmission & Distribution ("T&D") Operations organization, its role within the Company, and organizational leadership;
- introduce the divisions comprising T&D Operations, their functions and leadership, including my own group, TGO;
- provide an overview of some of Oncor's major operations-related initiatives since its last base-rate case, including a Transmission Management System ("TMS") replacement project, a refresh of its

telecommunication facilities, the establishment of a new back-up control center ("BCC"), and the transition of operational control for certain newly-acquired assets from Sharyland Utilities, L.P. and Sharyland Distribution & Transmission Services, L.L.C. (collectively, "Sharyland") to Oncor;

- describe how Oncor prepared for, and operated during, Winter Storm Uri and assessed the lessons learned from that event; and
- explain why Oncor's operation and maintenance ("O&M") expense costs associated with T&D Operations, and TGO specifically, are reasonable and necessary.

Q, DO YOU SPONSOR ANY EXHIBITS SUBMITTED BY ONCOR IN THIS PROCEEDING?

A. Yes. I sponsor Exhibits CMM-1, CMM-2, and CMM-3. These exhibits and this direct testimony were prepared by me or under my direction, supervision, or control and are, to the best of my knowledge and belief, true and correct. My direct testimony is organized consistent with the topics set forth above.

III. T&D OPERATIONS

A. T&D Operations Organization

Q. WHAT IS THE ROLE OF ONCOR'S T&D OPERATIONS ORGANIZATION?

A. The T&D Operations organization provides 24/7 system operations of Oncor's T&D facilities. To manage this sizeable undertaking, the organization is divided into seven divisions, each of which specializes in a discrete set of responsibilities critical to the safe and reliable operation of Oncor's T&D systems.

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE ORGANIZATIONAL STRUCTURE OF T&D OPERATIONS.

A. Each of the seven divisions within T&D Operations reports to Mark Carpenter, Oncor's Senior Vice President of T&D Operations. The seven divisions include:

- T&D Services;
- TGO;
- East Distribution Operations Center ("EDOC");
- West Distribution Operations Center ("WDOC");
- Environment and North American Electric Reliability Corporation ("NERC") Compliance;
- System Operations Distribution Administration; and
- Supervisory Control and Data Acquisition ("SCADA") Automation.

A chart depicting the organizational structure of T&D Operations, and additional details regarding the activities and leadership of each division, are included as Exhibit CMM-1 and Exhibit CMM-2 to my direct testimony, respectively.

B. Oncor O&M Costs Associated with T&D Operations

Q. PLEASE BRIEFLY SUMMARIZE ONCOR'S O&M ACTIVITIES ASSOCIATED WITH T&D OPERATIONS.

A. Stated generally, T&D Operations' O&M activities include all the activities required to operate the electric grid on a daily basis. This includes control room operations, system monitoring, coordinating outage restoration, coordinating with regulatory agencies and other utilities, conducting system analyses, maintaining records, and a host of other activities.

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE COSTS ASSOCIATED WITH ONCOR'S T&D OPERATIONS' O&M ACTIVITIES.

A. The 2021 O&M costs for Oncor's T&D Operations organization were $37,318,249. Of this amount, approximately $28.6 million is attributable to salaries and wages for full-time employees across the departments described in Exhibit CMM-2. Other major cost drivers for T&D Operations are contractor costs, outside services, and material and supplies. Outside services include costs associated with facilities maintenance, consulting services, and security services. Each of these categories together account for approximately 93% of T&D Operations' total O&M costs.

Q. ARE ONCOR'S T&D OPERATIONS' O&M COSTS REASONABLE AND NECESSARY?

A. Yes. T&D Operations' O&M dollars are largely spent on the people, activities, and facilities necessary to safely and reliably operate Oncor's T&D networks and to fulfill Oncor's environmental, compliance, and regulatory obligations. These people and the facilities that house them are absolutely essential to Oncor's ability to reliably operate the grid. Oncor's skilled and experienced workforce allows the Company to operate the grid efficiently and cost-effectively.

IV. TRANSMISSION GRID OPERATIONS

Q. PLEASE BRIEFLY DESCRIBE THE THREE WORK GROUPS WITHIN TGO THAT REPORT DIRECTLY TO YOU.

A. TGO consists of three primary work groups, including 24/7 control room staff, clearance coordination staff, and support engineering staff.

Q. PLEASE EXPLAIN THE KEY SERVICES TGO PROVIDES.

A. TGO is responsible for the safe and reliable remote operation of Oncor's transmission grid in coordination with the Electric Reliability Council of Texas, Inc. ("ERCOT") and other Transmission Operators across the system. In support of this objective, Oncor's 24/7 control room operations staff monitor and control transmission and substation facilities to ensure equipment is loaded within the applicable ratings. The control room operations team is also responsible for managing transmission voltages and reactive reserves using available dynamic and static reactive devices.

Following an outage on transmission or substation equipment, control room staff respond to direct the restoration of service, thereby reducing customer outage time and restoring system integrity. They also develop and implement switching orders to safely and reliably remove equipment from service as necessary for maintenance and construction activities. Oncor coordinates all switching actions, whether reactive or planned, with ERCOT, distribution personnel, and any potentially affected Transmission Operator or Generator Operator. Control room staff are trained to quickly respond to various system emergencies, including short supply and "Black Start" conditions. Control room staff are NERC-certified and must maintain their certification over time.

Oncor's clearance coordination staff is responsible for scheduling and coordinating all planned maintenance and construction activities with the control room. This includes proactively identifying and addressing any outage conflicts or otherwise infeasible outages before submitting the outage requests to ERCOT. It also includes working with ERCOT, Oncor's transmission districts, Oncor's construction management teams, Oncor's Transmission Program Management Office, and neighboring Transmission Operators and Generator Operators to develop outage schedules that will not jeopardize system reliability. Oncor obtains ERCOT approval before implementing outages unless failure to act prior to ERCOT approval could lead to an event that poses a threat to people, equipment, or public safety.

Oncor's support engineering staff performs operational power-flow and contingency analysis studies of the transmission grid. Engineers may be engaged by control room staff to provide support in assessing system conditions, identifying reliability issues and solutions, and resolving constraints. Additionally, support engineers perform seasonal assessments to develop various types of mitigation plans that are used by control room staff to ensure reliable operation during expected system conditions and following specific contingencies. Support engineers also support Oncor's clearance coordination staff by performing outage studies. These studies assist in identifying outages that may need to be rescheduled to maintain system reliability or to address market impacts. When it becomes necessary to obtain outages for critical maintenance and construction activities, these studies assist in identifying mitigating actions that can enable otherwise infeasible outages to proceed. Oncor's support engineering staff are also responsible for preparing procedures to guide control room staff in their response to various system emergencies, including short-supply and Black Start conditions.

Oncor has implemented processes and procedures to ensure its adherence to all compliance and regulatory obligations related to reliability and ERCOT market issues. All TGO personnel are responsible for maintaining a working knowledge of these processes and procedures, and specific personnel may be assigned to compile evidence necessary to demonstrate Oncor's compliance with regulatory obligations, including compliance with NERC Reliability Standards.

Q. PLEASE EXPLAIN ONCOR'S O&M COSTS THAT ARE ATTRIBUTABLE TO TGO.

A. The annual O&M costs for the TGO organization in 2021 were $9,157,814. This amount is included in the approximately $37 million in overall O&M costs described above. Of this amount, approximately $7.3 million is attributable to salaries and wages for TGO's approximately 60 full-time employees. Other major cost drivers for TGO are: (1) outside services, including facility maintenance, security services, and O&M costs paid to AEP to perform O&M activities for Oncor's share of the East Direct Current ("DC") Tie, which is jointly owned by Oncor, AEP Texas, AEP SWEPCO, and CenterPoint; and (2) rent and building expenses, such as utilities and janitorial services. Together, these categories account for almost 96% of TGO's 2021 O&M costs.

Q. WHAT HAVE BEEN THE PRIMARY DRIVERS OF ANY INCREASES IN TGO'S O&M COSTS SINCE ONCOR'S LAST BASE-RATE CASE?

A. TGO's O&M costs have generally remained consistent since Oncor's last base-rate case. The one notable exception to this is the increase in resources needed to safely and reliably operate assets Oncor acquired from Sharyland. This is in addition to the organic growth and associated construction and maintenance activities on Oncor's existing system, particularly in the west Texas area, where Oncor has seen substantial system growth since its last base-rate case as surging oil and gas production has driven a corresponding increase in electric demand.

Q. ARE TGO'S O&M COSTS REASONABLE AND NECESSARY?

A. Yes. TGO's O&M costs are overwhelmingly spent on the people and facilities necessary to safely and reliably operate Oncor's transmission grid. TGO's O&M costs are reasonable and necessary.

Q. WHY IS IT IMPORTANT FOR ONCOR TO RECOVER THE COSTS ASSOCIATED WITH ONCOR'S TRANSMISSION GRID OPERATIONS?

A. The expenses associated with TGO represent prudent investments to ensure the safe, reliable operation of Oncor's transmission system in accordance with the applicable regulatory requirements and reliability standards. These expenses represent the people, facilities, and tools that are necessary for Oncor to efficiently operate its system in coordination with ERCOT and other transmission service providers in ERCOT. As I describe below, even during the extreme conditions experienced during Winter Storm Uri, Oncor's system performed exceptionally well. This is largely thanks to the efforts of the people at TGO and Oncor's rigorous operational standards, practices, and procedures. If Oncor is not allowed to recover the costs required to operate the grid, Oncor's operations would have to be scaled back, which would put reliability at risk.

V. MAJOR INITIATIVES SINCE DECEMBER 31, 2016

A. TMS Replacement

Q. PLEASE EXPLAIN WHAT THE TMS IS AND WHY IT IS CRITICAL TO THE OPERATION OF ONCOR'S ELECTRIC GRID.

A. TMS is the system Oncor uses to manage the day-to-day operation of its transmission grid and the tool that Oncor uses to remotely monitor and control its transmission and substation facilities. It consists of real-time SCADA, system visualization capabilities, transmission network analysis applications, an operational data historian, an operator training simulator, and many other functions. The TMS communicates and interfaces with over 1,200 transmission facility locations to provide monitoring, situational awareness, and control of the Oncor transmission grid.

Robust availability and reliability of the TMS are essential because Oncor relies on the TMS for each of the following critical services:

- monitoring the overall transmission network and individual facilities, including energization status, equipment positions, alarms, operating limits, and various analog measurements to quantify the operating conditions;
- restoring the system with remote restoration capability;
- providing operations data to ERCOT and neighboring entities through Inter-control Center Communications Protocol ("ICCP") links over the ERCOT Wide-Area Network;
- monitoring and controlling facilities necessary to meet all Nuclear Plant Interface Requirements;
- implementing planned switching with monitoring and remote control capability for construction projects to support Texas growth, equipment repair, and maintenance for safety, grid reliability, and compliance;

- meeting load shed obligations to maintain system reliability when there is insufficient generation in ERCOT to meet the demand; and
- implementing the Black Start Plan with remote control capability to restore the integrity of Oncor's portion of the ERCOT system following a partial or complete blackout in ERCOT.

Q. PLEASE BRIEFLY DESCRIBE THE TMS REPLACEMENT PROJECT, INCLUDING BACKGROUND ON THE NEED FOR THE PROJECT.

A. Before the TMS replacement project, Oncor used a system to remotely manage the operation of its transmission grid that was installed in the mid-1990s. After numerous hardware and software updates, the most recent version of that system had reached the end of its useful life. Accordingly, Oncor engaged in a comprehensive review to investigate the market for a successor and determine a path forward. This culminated in Oncor replacing the system with a new TMS, provided by an energy and industry recognized technology vendor. In her direct testimony, Company witness Ms. Malia A. Hodges discusses the scope of work related to the TMS replacement project, the factors Oncor considered in deciding whether to upgrade or replace the TMS, and the alternative options considered before ultimately selecting the most suitable vendor for the TMS replacement.

Q. WHY WAS THE PREVIOUS TMS NO LONGER VIABLE?

A. As I mentioned, the previous TMS was installed about 25 years ago, and Oncor's installed version had begun showing its age. For each station added, the TMS requires at least one Remote Terminal Unit ("RTU") to collect operations data and execute remote control commands. Oncor's system currently includes roughly 1,500 RTUs, and Oncor has added an average of over 60 new RTUs each year since December 31, 2016. Oncor's previous TMS could only accommodate a limited number of RTUs and was approaching its maximum capacity, meaning a new TMS or another update would soon be required for Oncor to expand its transmission system or add new stations. The system databases and many of its third-party tools were nearing the end of their vendor support periods, the existing server models were no longer being manufactured and were incompatible with newer models, and servers and associated hardware had begun failing at an accelerating rate. Moreover, the previous system was programmed using mostly Fortran, a now-obsolete programming language, further limiting efficiency and reliability when interfacing with other third-party security and maintenance tools. Together, these factors severely limited Oncor's ability to maintain and expand its system using the previous TMS.

Q. DID ONCOR CONSIDER ANOTHER UPGRADE OF THE PREVIOUS SYSTEM RATHER THAN A REPLACEMENT?

A. Yes. However, the subsequent version of the previous product was a combination of several product lines and would have required a large data and display conversion effort. Ultimately, this would have essentially been a new TMS, due to the magnitude of the software and hardware upgrades required. Given the significant expense and effort this would entail, and given that Oncor had not conducted a comprehensive market review since the original installation, it was prudent for Oncor to explore the market and assess the full range of options before proceeding with an upgrade.

Q. WHAT ARE THE OPERATIONAL BENEFITS OF THE NEW SYSTEM COMPARED TO THE SIEMENS SYSTEM IT REPLACED?

A. The new TMS provides scalability that will support Oncor's growth for the foreseeable future. It employs more robust data validation tools, while preserving critical components such as Outage Management System integration and Training Simulator. It also includes more advanced maintenance tools that improve the way Oncor satisfies Critical Infrastructure Protection requirements promulgated by NERC. The selected product is more standardized across its customer base, which eliminates the need for special coding for individual utilities and can result in more robust patches and upgrades. The updated architecture provides improved security, while also allowing better integration with Oncor's other corporate systems. Further, the new system provides additional operational tools, including a State Estimator and contingency analysis tools, which are used for situational awareness only, but can also be employed to support ERCOT in monitoring operational security as needed. Finally, the new system offers better visualization of operational conditions on the transmission system, including a Graphical Information System, and will have better vendor support and self-service. In sum, the selected product undoubtedly provides for more efficient operation of the TMS.

Q. WHEN DID ONCOR TRANSFER ITS OPERATIONS TO THE NEW TMS?

A. Oncor transitioned operations to the new TMS on May 18, 2021.

Q. IS THE TMS REPLACEMENT USED AND USEFUL?

A. Yes. The TMS is in use and critical to Oncor's safe and reliable operation of Oncor's transmission system.

Q. WHAT WAS THE TOTAL CAPITAL PROJECT COST OF THE TMS REPLACEMENT?

A. The total capital project cost, including Oncor employee labor, third-party contract labor, and replacement of the TMS IT network, was approximately $53 million. These costs are reasonable and necessary, as they will ensure that Oncor can continue to safely and reliably operate its transmission system while meeting the increasing demand for electric power within ERCOT. Further support for the TMS replacement is included in the direct testimony of Company witness Ms. Hodges.

B. Telecommunications Refresh Program ("TRP") Project

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE TRP PROJECT.

A. Oncor, like most utilities, uses third-party telecommunication facilities to monitor its transmission system. Historically, communication links to stations required copper land lines that Oncor leased from telecommunications companies. However, in recent years, telecommunications companies have been focused on replacing older copper wires with more modern technologies like fiber-optic cables. As a result, maintenance of the existing copper land lines has been a low priority for many telecommunications companies.

One consequence of the deterioration of the copper land line networks has been a reduction in the remote-control capability and visibility for RTUs, which were in decline for years before reaching their lowest availability in 2017. To improve data transfer performance and RTU communication within Oncor's system, bring Oncor's telecommunications tools up to date, and make them ready for the future, Oncor began the TRP project, which will replace the aging telecommunications infrastructure with predominantly Oncor-owned solutions.

Q. WHY IS THE TELECOMMUNICATIONS NETWORK SO CRITICAL TO ONCOR TGO'S FUNCTION?

A. The remote control and monitoring functions of the TMS are crucial to grid operations and require a robust telecommunications network to function. SCADA functionality allows Oncor TGO to fulfill the critical operations objectives I described above, such as monitoring the transmission network, system restoration, load-shed obligations, Black Start, and others. SCADA will not function unless each of its components is operational, which includes the TMS, RTUs, and the telecommunications network to connect them. TGO will lose visibility and control capability of a station if the associated station communication channel is inoperable, even with an operable TMS and station RTU.

Q. DOES THE REPLACEMENT INFRASTRUCTURE SIGNIFICANTLY OUTPERFORM THE AGING TELECOMMUNICATIONS NETWORK?

A. Yes. In executing the TRP project, Oncor has invested in long-haul and short-haul fiber connections, backhaul microwave system upgrades, procurement of 700 megahertz spectrum, and associated network upgrades. The new solutions also include point-to-point radio, point-to-multipoint radio, and other technologies to improve substation communication. As a result, the RTUs that have already transitioned to a TRP solution are consistently performing at 99% or greater availability, compared with a combined average of 93.6% just a few years ago, and the average system-wide performance has increased to 99%.

Q. WHAT ARE SOME OF THE BENEFITS OF ONCOR CONTROLLING ITS OWN TELECOMMUNICATIONS INFRASTRUCTURE?

A. Installing Oncor-owned and -managed communication infrastructure has many benefits. Perhaps most importantly, it eliminates Oncor's reliance on telecommunications companies for facilities essential to the operation of its electric grid. This allows Oncor to prioritize and coordinate maintenance needs and outage response related to its communication infrastructure. It also ensures that the current and future capacity needs of the TMS are not limited by inadequate data transfer capabilities. Oncor can utilize available capacity above the TMS requirements for other corporate needs, such as securely downloading supplemental station event data, physical security information, and maintenance information. An independently owned communication network also safeguards availability during short-supply events, Black Start situations, or other situations where public systems may become overloaded or incapacitated.

Q. HOW MUCH HAS ONCOR INVESTED IN THE TRP PROJECT?

A. Oncor has invested approximately $168 million in the TRP project.

Q. ARE THE TRP PROJECT INVESTMENTS REASONABLE AND NECESSARY?

A. Yes. As I mentioned, the existing network was in a long-term state of decay, and Oncor's ability to monitor and control its RTUs was becoming compromised as a result. Accordingly, an upgrade was necessary for the continued safe and reliable operation of Oncor's transmission system. Oncor, and ultimately its customers, are already reaping operational benefits where replacement solutions have been installed. Further, installing predominantly Oncor-owned solutions will keep the network under Company control, ensuring that Oncor is able to maintain and operate its system at optimal efficiency with minimal dependence on third-party entities. Additional information on the TRP project is available in the direct testimony of Company witness Ms. Hodges.

C. New Backup Control Center

Q. PLEASE EXPLAIN THE NEED TO ESTABLISH A NEW BCC FROM AN OPERATIONS STANDPOINT.

A. Oncor established a new BCC to address concerns with the previous BCC's aging electrical and heating, ventilation, and air conditioning ("HVAC") systems and to provide additional space necessary to house a fully-staffed control room. The previous location did not have a number of important capabilities, including automatic throw-over schemes for electrical security and adequate redundant HVAC for operations and server areas. The aging uninterruptible power supply ("UPS") system's ability to sustain power to critical assets also required upgrading.

The previous BCC also lacked sufficient space to adequately house all of Oncor's operations personnel. Increased demand for electric power in Texas has led to a commensurate increase in Oncor's operational activity, which has driven the need for additional personnel, requiring more space than the previous facility could offer.

Finally, the decision to establish a new BCC was due in part to the fact that Oncor had decided to vacate the downtown Fort Worth office building in which the BCC was then located and move to a new location.

Q. HOW IS THE NEW BCC LOCATION SUPERIOR TO THE FORMER LOCATION?

A. The new BCC facility includes new electrical transfer switches that detect loss of power and transfer to an alternate source for power restoration. New HVAC systems were also installed that are capable of providing cooling to critical equipment in the event that part of the cooling system becomes unavailable. Additionally, the installation of new UPS systems provides a power source to critical equipment during the power transfer process. These upgrades provide the reliability necessary for control room operations.

In addition, the new BCC facility offers a better layout and added space for control room operations. The added space has been invaluable to TGO as Oncor has responded to the COVID-19 pandemic, as it has facilitated a greater level of social distancing in the control room.

Q. DID THE TMS REPLACEMENT IMPACT THE CHANGEOVER TO A NEW BCC?

A. Yes. Oncor timed its establishment of a new BCC to coincide with the TMS replacement project in order to accomplish both projects more cost-effectively. Establishing the new BCC after the TMS replacement project had already occurred would have required the new system to be installed once in the existing BCC, and then again in the new BCC. On the other hand, establishing a new BCC prior to the TMS replacement project would have required an initial installation of the old system in the new location, followed by an installation of the new TMS system shortly thereafter. Timing the two to coincide with one another reduced the overall costs and effort associated with the TMS replacement project.

Q. WHAT WAS THE COST OF ESTABLISHING A NEW BCC?

A. The total cost to establish a new BCC, including the relocation itself and installing the necessary systems and equipment, was approximately $6.4 million.

Q. FROM AN OPERATION STANDPOINT, ARE THE COSTS ASSOCIATED WITH ESTABLISHING A NEW BCC REASONABLE AND NECESSARY?

A. Yes. The costs associated with the new BCC were closely monitored and controlled during the planning and building process. The new BCC location was chosen based on the necessity for secure and reliable operations. The electrical, HVAC, and security systems in place in the new location, along with the superior space and design, provide Oncor with a long-term BCC solution at a reasonable cost.

D. Sharyland Operations Transition

Q. PLEASE BRIEFLY EXPLAIN THE SHARYLAND OPERATIONS TRANSITION.

A. The Sharyland operations transition resulted from the transactions approved by the Commission in Docket No. 48929. Under the Commission's order in that docket, Oncor Electric Delivery Company NTU LLC ("Oncor NTU"), an indirect, wholly-owned subsidiary of Oncor, took possession of certain Sharyland assets ("Oncor NTU Assets"), while Sharyland retained ownership of certain T&D assets in south Texas. The Commission ordered Oncor to provide all O&M services for the Oncor NTU Assets and certain operations services for the Sharyland assets. The details of these transactions are described in greater detail in the direct testimony of Oncor witnesses Mr. Wesley R. Speed and Mr. James A. Greer. Additionally, Oncor witness Mr. Michael G. Grable provides additional details regarding the services provided to Oncor NTU and Sharyland in his direct testimony. As a part of this transfer, Oncor transitioned operational control of the Oncor NTU Assets and Sharyland assets from Sharyland's Amarillo control center to Oncor's control center in the Dallas-Fort Worth ("DFW") area. Oncor coordinated with Sharyland and ERCOT to establish an operations transition plan for the Oncor NTU Assets and Sharyland assets with a framework focusing on maintaining the integrity of operations reliability, resource efficiency, and compliance. The operations transition was planned on an accelerated timeline to avoid ERCOT's summer outage restriction timeframe and to execute almost all aspects of its operations changeover prior to the close of the transactions approved in Docket No. 48929.

Q. WHAT PLANNING AND ACTIONS WERE REQUIRED TO SUCCESSFULLY EXECUTE THE TRANSITION?

A. Prior to the transition, Oncor reviewed Sharyland's documentation, in-flight projects, operations and planning models, systems, and applications for various transition objectives. Oncor modeled Sharyland's facilities in Oncor's TMS, including ICCP and RTU operation data points. Oncor repurposed some of Sharyland's existing communications infrastructure and, where necessary, installed new communications equipment to establish SCADA communications to Sharyland's facilities. The establishment of SCADA communications and RTU programming was planned and executed to minimize and, where possible, eliminate the duration of time for which ERCOT, Sharyland, and Oncor would lose operational visibility and control during SCADA functional testing and operations changeover.

Oncor and Sharyland performed SCADA functional testing for all RTU points for which testing was feasible. There were well over 15,000 RTU points tested manually to ensure safe and reliable grid operations for Oncor, ERCOT, and the general public.

In collaboration with Sharyland and ERCOT, Oncor executed ERCOT model changes to show the addition of Oncor ownership, operational responsibility, adjustments to facility ratings per Oncor Facility Ratings Methodology, and provision of real-time telemetry to ERCOT by Oncor. To ensure accurate data was being provided from the assets previously owned by Sharyland to ERCOT, Oncor established a temporary test environment with ERCOT's backup system and performed several iterations of data quality verification with ERCOT.

Oncor updated standard documents and procedures to incorporate Sharyland facilities, including special transmission assets such as Synchronous Condensers and DC Ties. Oncor also developed and provided training sessions for Oncor's Transmission Grid Operators.

Oncor assessed Sharyland's documentation for NERC, ERCOT, and other reliability compliance requirements. Sharyland's current projects under construction were appended to Oncor's project management applications to be tracked during and after the operations transition. Oncor also updated other Oncor applications with Sharyland's assets, including the Transmission Outage Application, Transmission Interruption Report System, and Transmission Network Applications.

Q. WHAT WAS THE OUTCOME OF ONCOR'S TRANSITION EFFORTS?

A. At the end of transition, Oncor had successfully extended its operations capability to all Oncor NTU Assets and Sharyland assets and decommissioned Sharyland's TMS, circuits, servers, and security devices in Sharyland's primary and backup Amarillo control centers. This was done with no reduction in service to former Sharyland customers or to existing Oncor customers. Neither Oncor nor ERCOT experienced any unintended loss of grid visibility for Sharyland and Oncor facilities, and there were no material issues in Oncor TMS data quality or the ERCOT system changes applied by Oncor.

Q. HOW DID CUSTOMERS BENEFIT FROM THE TRANSITION PROCESS?

A. Transitioning control of the Oncor NTU Assets to Oncor and eliminating the former Sharyland control centers ultimately reduced overall operating costs. Oncor's combined costs to operate its legacy system and the Oncor NTU Assets together is less than the combined historical costs for Oncor and Sharyland to operate each independently. These avoided costs result from the efficiencies gained from operating the Oncor NTU Assets and Oncor's legacy facilities as a single, cohesive system and from the overhead saved by retiring Sharyland's Amarillo control centers.

Q. ARE THE COSTS OF THE SHARYLAND TRANSITION REASONABLE AND NECESSARY?

A. Yes. The costs were necessary to (i) effectuate the Commission's order in Docket No. 48929, and (ii) ensure customers enjoyed the benefits of the transaction. Wherever possible, Oncor used comprehensive advanced planning and coordination with Sharyland and ERCOT to foresee and counter potential difficulties during the transition that might have resulted in additional complications. In doing so, Oncor transitioned the Oncor NTU Assets to its control in a safe, efficient, and cost-effective manner. Moreover, by consolidating Sharyland's operations into Oncor's DFW control centers, Oncor eliminated unnecessary overhead costs.

E. Operation Services Provided to Oncor NTU

Q. PLEASE DESCRIBE THE OPERATIONAL SERVICES ONCOR IS RESPONSIBLE FOR PROVIDING TO ONCOR NTU.

A. Following the Commission's approval of the Sharyland transactions, Oncor NTU became an Oncor affiliate with no employees or management of its own. Accordingly, under the Commission's order in Docket No. 48929, Oncor assumed responsibility for providing all O&M services to the Oncor NTU Assets. This includes monitoring and controlling facilities, switching and restoration activities, clearance coordination, system modeling, NERC compliance services, and smart grid communications, among others.

Q. IS ONCOR CURRENTLY PROVIDING O&M SERVICES TO ONCOR NTU?

A. Yes, Oncor provides O&M services for the Oncor NTU Assets in exactly the same manner as the assets Oncor owns directly.

Q. HOW DOES ONCOR ALLOCATE COSTS INCURRED FOR ONCOR NTU SERVICES?

A. Services provided by Oncor to Oncor NTU are provided at Oncor's cost, pursuant to the affiliate cost methodology that has been filed with and approved by the Commission in Docket No. 49851. The goal of this methodology is to allocate costs incurred by Oncor and its affiliates in a manner that is reasonable and consistent with the cost drivers for each entity. Under the affiliate cost methodology, wherever possible, operating costs are billed directly to the cost-causing entity. Remaining cost assignments are calculated based on a cost-causation methodology, which takes into account certain variables to assign costs arising from associated corporate functions. Generally, the total cost assigned to an entity is equal to the sum of that entity's cost assignments for select services (including a corporate support percentage to cover administrative and indirect costs incurred to provide the services) plus carrying costs and a total cost of ownership allocation. Oncor witness Mr. Grable provides additional details regarding these transactions in his direct testimony.

Q. PLEASE EXPLAIN THE COST-SHARING VARIABLES AND PROCESS USED FOR ASSIGNING COSTS.

A. The variables used to set cost assignments are distinct for each service provided. For example, costs for operation services are set based on the total number of switching stations and substations each entity owns. This is because the cost drivers for operations activities (*e.g.*, monitoring, controlling, switching) are closely related to the number of stations an entity owns. Similarly, costs for metering services are assigned proportionally based on the number of meters each entity owns because the cost of metering services is closely tied to the number of meters that need to be read. The following table lists the major categories of O&M costs for services provided by Oncor to Oncor NTU and/or Sharyland and the variables associated with each:

Cost Category	Associated Variables
Operation Services	• Station Count
DC Tie Operations	• Control Room Resources • DC Tie Hours per Year
ERCOT-Polled Settlement ("EPS") Metering Services	• EPS Meter Counts • System Metering Organization Full-Time Employees
Wholesale Metering Services	• MV90 Meter Counts • Advanced Metering System ("AMS") Operations Group Full-Time Employees
Maintenance and Other Services	• Station Count • Line Miles

F. Operation Services Provided to Sharyland

Q. PLEASE DESCRIBE THE SERVICES ONCOR IS PROVIDING TO SHARYLAND.

A. Under the Commission's order in Docket No. 48929, Oncor currently provides transmission operation services, DC tie operation services, EPS metering services, and wholesale metering services to Sharyland. Transmission operation services include monitoring and controlling of facilities, switching and restoration activities, clearance coordination, operations center infrastructure, and smart-grid communications. DC tie operations entail the control room resources required to operate a DC tie on Sharyland's behalf. Additionally, Oncor is registered with NERC as the Transmission Operator for certain Sharyland facilities. In this role, Oncor is responsible for operating Sharyland's facilities and ensuring compliance with identified NERC reliability standards.

Q. HOW IS ONCOR REIMBURSED FOR THE SERVICES PROVIDED TO SHARYLAND?

A. Just as they are for the Oncor NTU Assets, the costs associated with operating the Sharyland assets are assigned in accordance with the affiliate cost methodology described above and in the direct testimony of Company witness Mr. Grable. These costs are also addressed in the direct testimony of Company witness Mr. W. Alan Ledbetter.

Q. IS ONCOR SEEKING RECOVERY FOR THE COSTS ASSOCIATED WITH THE O&M SERVICES PROVIDED TO SHARYLAND?

A. No. Costs associated with Sharyland assets are allocated to, and reimbursed by, Sharyland. During the 2021 test year, these costs were $626,833.35. One purpose of the affiliate cost methodology is to ensure that Oncor's customers are not responsible for paying for Sharyland's assets or their cost of operation. As such, the net costs for which Oncor seeks recovery do not include expenses for providing O&M services to Sharyland.

VI. OPERATIONS DURING WINTER STORM URI

A. Pre-storm Planning and Preparation

Q. PLEASE DESCRIBE ONCOR'S EMERGENCY PLANS, POLICIES AND PROCEDURES IN EFFECT PRIOR TO WINTER STORM URI.

A. Oncor's emergency plan was in effect well before Winter Storm Uri of February 2021. Oncor maintains documentation of its detailed emergency operations procedures and processes in various documents, including but not limited to the following: the Emergency Restoration Plan, which is activated to re-deploy equipment and personnel throughout the Company to concentrate on service restoration; the System Emergency Operation Procedures Manual ("SEOPM"), which documents actions to take in the event of a system-wide short generation supply situation in ERCOT; the Black Start Plan, which documents actions to take in the event of a partial or complete system black out; the Pandemic Readiness Plan; and the Wildfire Mitigation Plan. Further descriptions of the Emergency Restoration Plan, the SEOPM, and the Black Start Plan are provided in the direct testimony of Company witness Mr. Keith Hull. Company witnesses Ms. Buck and Mr. Hull provide additional discussion of the Pandemic Readiness Plan.

Q. HAS ONCOR FILED AN EMERGENCY OPERATIONS PLAN WITH THE COMMISSION?

A. Yes. Oncor filed its Public Utility Commission of Texas Emergency Operations Plan with the Commission on April 14, 2022, as required by 16 Tex. Admin. Code § 25.53(c). This plan complies with the requirements of that provision and includes Oncor's Communications Plan, Plan to Maintain Pre-Identified Supplies for Emergency Response, Plan to Address Staffing During Emergency Response, and Plan for Identification of Weather-Related Hazards and Process to Activate the Emergency Operations Plan, as well as Annexes describing Oncor's policies and procedures for monitoring and responding to weather emergencies, load-shed directives, pandemic and epidemic conditions, wildfire, cyber security, and physical security incidents.

Q. PLEASE DESCRIBE WINTER READINESS MEASURES PERFORMED BY ONCOR.

A. Oncor prepares for winter conditions by communicating a checklist to all transmission work centers, which are required to follow the checklist in order to prepare stations and equipment for the cold weather. The checklist covers switching stations, substations, mobile substations, facilities, emergency generators, transportation, and personal protective equipment and safety items for personnel. Examples of station items checked under this process include: station batteries, fuel levels on station generators, equipment heaters, transformer nitrogen pressures and oil levels, and sulfur hexafluoride gas pressure in applicable circuit breakers. Substations are also inspected with infrared thermography to check for hot spots on connectors, bus work, and jumpers. Oncor also ensures operational readiness through monthly patrols of Oncor's station facilities.

Q. PLEASE DESCRIBE ADDITIONAL ACTIONS TAKEN BY ONCOR TO PREPARE FOR WINTER STORM URI.

A. Oncor began preparing for Winter Storm Uri well in advance of the first ERCOT load-shed directive, as generally discussed in the direct testimony of Company witnesses Mr. Greer and Mr. Hull, and as shown in Mr. Greer's Exhibit JAG-7. On February 6 and 7, 2021, Oncor began securing additional contractors in anticipation of potential storm restoration work. On February 8, 2021, Oncor coordinated with ERCOT to evaluate Oncor's scheduled transmission outages that were then in effect, in an effort to identify and restore outages that would be impactful to generation deliverability or had the potential to cause significant transmission system constraints. From February 8-14, 2021, Oncor returned certain transmission facilities to service based on the priority identified through Oncor's coordination with ERCOT. Also, Oncor postponed scheduled work to ensure that the system was fully prepared for the storm.

Oncor also increased staffing at its T&D control centers to ensure personnel were ready to respond to weather conditions and ERCOT directives. Additional support personnel were brought on-site, and crews were staged and ready for dispatch.

B. Winter Storm Timeline

Q. PLEASE DESCRIBE THE WINTER STORM URI TIMELINE FROM ONCOR'S OPERATIONAL PERSPECTIVE.

A. As noted above, on February 8, 2021, ERCOT issued an Operating Condition Notice for an approaching extreme cold weather system with temperatures expected to remain at or below freezing from February 12-16. At this point, Oncor began identifying all active outages and verifying emergency restoration times. Oncor also reviewed its planned project portfolio and canceled scheduled transmission outages that had scheduled end dates later than February 12. On February 9, 2021, TGO coordinated with ERCOT to identify active outages that could be withdrawn and restored for the benefit of the ERCOT system.

Throughout the week of February 8, 2021, Oncor: (i) in coordination with ERCOT, restored all construction-related outages that might have impacted generation availability or caused significant transmission system constraints; (ii) confirmed that cabinet heaters were operational at critical stations; (iii) participated in daily calls with IBM meteorologists; and (iv) verified employee and vehicle winter preparedness.

During that same week, Oncor also ordered and deployed material historically impacted by cold weather to storerooms across Oncor's service territory, distributed nearly 700 transformers from Oncor's central warehouse of vendor-owned inventory to Oncor service centers, expedited all incoming orders of transformer units and items predicted to be most heavily impacted by the weather, secured two material staging sites in the DFW area, and maintained consistent communication with suppliers to ensure their availability and gauge their ability to respond to Oncor's needs during and after the event.

On February 10 and 11, 2021, ERCOT issued an Advisory and a Watch, respectively, for an approaching extreme cold weather system with temperatures expected to remain at or below freezing from February 12 to 16.

On February 11, 2021, Oncor sent an email to all 1,462 Large Commercial and Industrial ("LCI")-assigned accounts to inform them of the impending severe weather and encourage them to sign up to receive ERCOT alerts.

On February 13, 2021, ERCOT issued an Operating Condition Notice that Physical Responsive Capability ("PRC") was less than 3,000 megawatts ("MW"). ERCOT also issued an Emergency Notice warning of an extreme cold weather condition that had begun to adversely impact the transmission system, causing high demand and reduced generation availability, and warning operators to prepare for higher than usual loads and the possibility of load shedding.

On February 14, 2021, ERCOT issued an appeal to the public for voluntary energy conservation. ERCOT also issued several Watch notices throughout the day for insufficient ancillary services, projected reserve capacity shortage with no market solution, and a freezing precipitation event. Oncor opened and staffed its Transmission Emergency Center and System Emergency Center and increased staffing at EDOC and WDOC in preparation for the coming storm. Oncor also secured hotel rooms for its crews, deployed contractors to Central and East Texas, and began 24-hour operations at all supply-chain, material and equipment distribution centers. DFW area staging sites became operational with equipment and material delivered and prepared. At 11:30 PM, ERCOT issued an Advisory for PRC being below 3,000 MW.

On February 15, 2021, at 12:10 AM, ERCOT issued a Watch for PRC dropping below 2,500 MW. Between 12:15 AM and 1:20 AM, ERCOT separately issued Energy Emergency Alert ("EEA") Level 1, Level 2, and Level 3 and issued the first load-shed instruction of the winter storm, directing utilities to shed 1,000 MW of ERCOT load. From 1:45 AM through 6:44 PM, ERCOT issued numerous additional load-shed instructions with an aggregate peak ERCOT load shed of 20,000 MW, which coincided with Oncor's peak customer outage of over 1.3 million customers. At the end of the day on February 15, 2021, ERCOT load shed remained at 19,000 MW.

Oncor implemented its portion of the ERCOT load shed and restoration instructions throughout the day on February 15. During that day, Oncor personnel worked in the field through the storm while we rotated customer outages to the extent possible, deployed material storm kits to its Tyler service center, began sourcing for alternative fuel suppliers to address fuel scarcity for Oncor's fleet and facilities, communicated to all 1,462 LCI accounts to keep them informed and call for conservation, and provided Oncor media updates. The Company also reached out to transmission-level customers, asking them to conserve energy.

On February 16, 2021, ERCOT issued numerous load shed and restoration instructions, and the ERCOT load shed fluctuated between 15,000 MW and 19,500 MW. The ERCOT load shed remained at 15,500 MW at the end of that day. Throughout the day, Oncor personnel continued to work in the field through the storm while Oncor continued to rotate customer outages to the extent possible and maintained communication with customers. Oncor secured three new staging sites in Belton, Tyler, and Lufkin, and deployed transformer supplies and material storm kits to those sites.

On February 17, 2021, ERCOT issued one load-shed instruction and numerous load restoration instructions. By 11:55 PM, there was no more ERCOT-directed load shed remaining. Again, throughout the day, Oncor personnel worked in the field through the storm while Oncor rotated customer outages to the extent possible and maintained communication with customers.

Oncor's timely implementation of ERCOT's load-shed instructions from February 15-17 was critical to preventing the entire ERCOT system from blacking out. Upon receiving load-shed instructions from ERCOT, Oncor implemented its share of load shed in a timely manner, thus preventing a much more significant system-wide blackout. Such an event would have been devastating for Texans, as it would likely have taken an extended period of time to restore the grid to full operation. In the interim, families and businesses across the state would have been without power for days or weeks beyond what they experienced during the controlled load shed.

On February 19, 2021, at 9:00 AM, ERCOT moved from EEA Level 3 to EEA Level 2. At 10:00 AM, ERCOT moved from EEA Level 2 to EEA Level 1. At 10:35 AM, ERCOT cancelled EEA Level 1, the Watch and Advisory for PRC, and returned to normal operation. ERCOT also cancelled the Operating Condition Notice for adverse weather conditions.

From February 18-21, 2021, Oncor continued to restore service to customers at the distribution device or feeder level, kept crucial supply chains operational, and maintained its communication with customers. On February 21, 2021, at 7:30 AM, EDOC concluded its storm restoration work, and at 5:10 PM, WDOC concluded its storm restoration work.

C. Assessment of Oncor's Performance

Q. PLEASE DESCRIBE ONCOR'S LOAD-SHEDDING PLAN.

A. Oncor's load-shedding plan details how Oncor will shed load and rotate outages during load-shed events. The load-shedding plan is managed by a cross-functional team of stakeholders from across the Company and is reviewed twice a year as part of Oncor's SEOPM updates. While Oncor continues to maintain separation between manual load shed feeders and under-frequency load shed ("UFLS") feeders, Oncor has modified its processes to allow operators to incorporate a portion of the UFLS feeder load into the load-shed process when system conditions allow, which will distribute the burden of a significant load shed event across more customers Specific facilities that serve major airports, downtown networks, and military facilities are excluded from the load-shedding plan for technical and security reasons. Feeders that serve hospitals, 911 call centers, and facilities that are known by Oncor through communications by customers to be critical to the transportation of natural gas for power plant operations are also excluded from rotating outages under Oncor's load-shedding plan.

Oncor's control room personnel also practice for load-shed events and Black Start events at least once a year. It is critical for Oncor's operators to be proficient at handling load shed and short-supply events to avoid Black Start situations.

Q. WHAT WERE ONCOR'S OPERATIONAL PRIORITIES DURING THE WINTER STORM?

A. Oncor's top operational priority during Winter Storm Uri was to ensure the security of the ERCOT grid and avoid a full system blackout. This required timely and accurate execution of ERCOT operating instructions for load shed. Other key operational priorities during the load-shed event were to prioritize continuity of power to customers that are critical to public health, welfare of the community, or the integrity of the electric system, and to be as effective as possible at rotating outages to minimize the impact to all customers while maintaining geographic diversity.

Q. WHAT WAS ONCOR'S GOAL WITH RESPECT TO OUTAGE DURATION FOR EACH CUSTOMER?

A. Oncor's goal during load-shed events is to maintain 15-30 minute outage rotations.

Q. HOW DID ONCOR PERFORM IN ACHIEVING ITS GOAL WITH RESPECT TO OUTAGE DURATION?

A. For the first hour of the load-shed event on February 15, Oncor had no issues meeting its goal with respect to load-shed duration. As ERCOT instructed additional load to be shed, the number of feeders required to be de-energized grew, and as a result, more feeders experienced outages for longer periods of time.

As feeders that were out for sustained periods were re-energized, customers who had been without electricity drew increasing amounts of power. In order to compensate for this added load, more feeders had to be de-energized to maintain the rotation and comply with the ERCOT-instructed load shed. Moreover, through this event, a number of feeders with critical public infrastructure or generation support were brought to Oncor's attention and were actively removed from the rotating outage list.

The added load, increase in the ERCOT load-shed requirements, and exclusion of additional feeders from the rotating outage list compounded to a point where Oncor was unable to effectively maintain Oncor's rotation-duration goal until ERCOT directed Oncor to add additional load back to the system.

Q. DID ONCOR EXPERIENCE A SIGNIFICANT AMOUNT OF TRANSMISSION FACILITY OUTAGES DURING WINTER STORM URI?

A. No. In fact, during the entire period between November 30, 2020 and March 1, 2021, Oncor only experienced five discrete cold weather critical component issues that caused a piece of transmission equipment to experience an outage, all of which occurred during Winter Storm Uri. These included one autotransformer and four circuit breakers and represent less than 0.17% of Oncor facility locations. While none of these events caused a lengthy outage that affected either generation output or customers, the minor component issues that Oncor experienced did require short outages to repair or replace the component causing the operational issue. Oncor's 2021-2022 winter preparedness checks of all station circuit breakers addressed these failures through the evaluation of sulfur hexafluoride levels and potential leaks; control cabinet heaters and adequacy of door seals to ensure proper insulation; verification of proper oil levels; and addition of oil where necessary for all autotransformer equipment.

Q. DID LOAD-SHED IMPACT TRANSMISSION-LEVEL CUSTOMERS?

A. While Oncor is permitted by Commission rules to shed load at both transmission and distribution levels, Oncor has not historically shed load at the transmission level and did not shed load at the transmission level during this event because of the more highly interconnected nature of the transmission system.

However, during this event, Oncor conferred with LCI customers and with the Texas Industrial Energy Consumers trade association in an effort to obtain as much voluntary load shed as possible and to warn of the risk of potential involuntary transmission load shed. As a result, the magnitude of demand response from transmission-level customers on a percentage basis well exceeded the percent of load shed that was experienced across the system. This significant reduction in demand from transmission-level customers ultimately reduced the impact to all other customer classes.

D. Lessons Learned and Areas for Improvement

Q. WHAT HAS ONCOR DONE TO INCREASE THE VOLUME OF LOAD AVAILABLE FOR LOAD SHED IF ROTATING OUTAGES ARE MANDATED IN THE FUTURE?

A. Oncor sponsored Protocol and Guide revisions at ERCOT that will allow electric utilities to exercise more flexibility between distribution feeders available for manual load shed and those set aside for UFLS during major load-shed events. This change represents an opportunity to increase the amount of load available to respond to ERCOT-directed load shed and improve the effectiveness of outage rotations for load that is in rotation.

Using data from the TMS, Oncor has implemented the necessary monitoring capability to calculate the difference between the UFLS load required to meet its UFLS obligations and the actual load on its UFLS circuits. Oncor can use this "margin" to shed load and rotate outages while still meeting its UFLS obligations to ERCOT. This approach will increase the amount of load available for rotating outages, spread the burden of those outages over a larger and more diverse pool, and provide added operational flexibility. It also reduces the risk of an overshoot in frequency if UFLS operations occur when actual UFLS-connected loads substantially exceed the required obligations. Additionally, Oncor has collaborated with the Texas Reliability Entity to create a Lessons Learned document addressing this topic, which was approved by NERC and widely distributed to electric utilities across North America.

Q. HAS ONCOR COORDINATED WITH STAKEHOLDERS TO IMPROVE IDENTIFICATION OF CRITICAL NATURAL GAS FACILITIES?

A. Yes. In March 2021, Oncor collaborated with Commission Staff and the other electric utilities in Texas to make revisions to the Form "Application for Critical Load Serving Electric Generation and Cogeneration." Those revisions allow electric utilities to capture more detailed information about the critical gas facilities in Texas, providing Oncor with better visibility into the natural gas supply chain and potential impacts if directed to shed load. Additionally, Oncor participated with other transmission and distribution utilities operating within the ERCOT power region ("Joint TDUs") in natural gas-related rulemakings at the Commission and the Railroad Commission of Texas ("RRC"). The Joint TDUs filed comments in Commission Project No. 52345 regarding amendments to 16 TAC § 25.52, which governs the process for critical natural gas customer designation and the provision of related information to ERCOT, where applicable, and requires utilities to incorporate this information into their load-shed and emergency restoration plans. Additionally, the Joint TDUs filed comments in the RRC's rulemaking to create the new 16 TAC § 3.65, relating to the critical designation of natural gas infrastructure and its associated critical information tables. Due in part to these efforts, since Winter Storm Uri, Oncor has approved critical load gas applications for more than 3,300 premises and has worked closely with the Commission to provide electric mapping information for these premises. Importantly, it is the facility owner that must submit information to the RRC prescribed by rule for a critical-facility designation. Oncor relies on the submission of information from facility owners and operators. Finally, Oncor Vice President of Regulatory Affairs, Liz Jones, was appointed to represent T&D utilities on the Texas Energy Reliability Council, which was created by Senate Bill 3 to (1) ensure that the energy and electric industries in this state meet high priority human needs and address critical infrastructure concerns, and (2) enhance coordination and communication in the Texas energy and electric industries.

Oncor will also continue to make it a priority to ensure that, to the extent possible, natural gas critical load continues to receive power during a load-shed event. During the winter of 2020-2021, approximately 44% of Oncor's load was available for manual load shed during short-supply events. For the winter of 2021-2022, that number dropped to 34%, due largely to the exemption of natural gas critical loads. Nonetheless, the UFLS margin discussed above provides enough additional load to compensate for this decline.

Q. HAS ONCOR IMPROVED ITS COORDINATION WITH MUNICIPALITIES TO BETTER PREPARE FOR AND OPERATE DURING AN EMERGENCY?

A. Yes. Many of the municipalities Oncor serves have their own emergency operation centers with a seat reserved for an Oncor employee trained in emergency preparedness and response. Oncor's area managers and the Liaison Section of Oncor's System Emergency Center also work closely with municipalities to identify critical loads and other key municipal infrastructure during emergencies, as well as other contingency plans.

In an effort to identify municipal critical loads, Oncor has implemented an annual critical-load outreach to municipalities served by Oncor. In February of each year, Oncor's area managers will provide municipalities with a list of all of their premises that are designated as critical load along with pertinent contact information and related data. Area managers will request municipalities to confirm the information and add or delete critical premises as needed.

Oncor has also created an internal communications guide to be used in the event of an ERCOT EEA Level 2 or 3 event. The guide provides standardized outreach messages to be communicated to Oncor's external partners, including municipalities, during ERCOT Energy Emergencies. In addition to providing valuable information to the municipalities, depending on the level of the ERCOT energy emergency, the messaging also includes links to webpages for ERCOT and Oncor, as well as to Oncor's document titled, "Important Information About Electricity Load Shedding and What It Could Mean to You."

VII. SUMMARY AND CONCLUSION

Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY.

- Oncor's T&D Operations organization provides 24/7 system operations of Oncor's T&D facilities, including 24/7 control-room operations carried out by my organization, TGO and the two DOCs. This also includes system monitoring, coordinating outage restoration, coordinating with regulatory agencies and other utilities, conducting system analyses, maintaining records, and many other activities. Oncor's costs associated with TGO and T&D operations are reasonable and necessary.
- Oncor has undertaken several operations-related initiatives to ensure its continued ability to operate the grid safely and reliably. These include the TMS Replacement Project, the TRP project, and migrating to a new

BCC. These were prudent investments that will result in a safer, more reliable transmission grid.

- Pursuant to the Commission's order in Docket No. 48929, Oncor operates and maintains certain assets owned by Oncor NTU in exactly the same manner as it operates and maintains its own facilities. Oncor also provides certain operation services to Sharyland as required by the Commission's order.
- Oncor took a number of actions in preparation for Winter Storm Uri and executed ERCOT's load-shed and restoration directives to prevent a system-wide blackout of the ERCOT grid. As a result, Oncor's system performed exceptionally well during the storm.
- Oncor coordinates with stakeholders, including the Commission, local governments, ERCOT, other utilities, and natural-gas providers, has policies and procedures in place to ensure it can continue to provide safe and reliable electricity, even during emergency conditions.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

AFFIDAVIT

STATE OF TEXAS §
§
COUNTY OF DALLAS §

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

My name is Collin M. Martin. 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.

Collin M. Martin

SUBSCRIBED AND SWORN TO BEFORE ME by the said Collin M. Martin this 18th day of April, 2022.

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

Notary Public, State of Texas

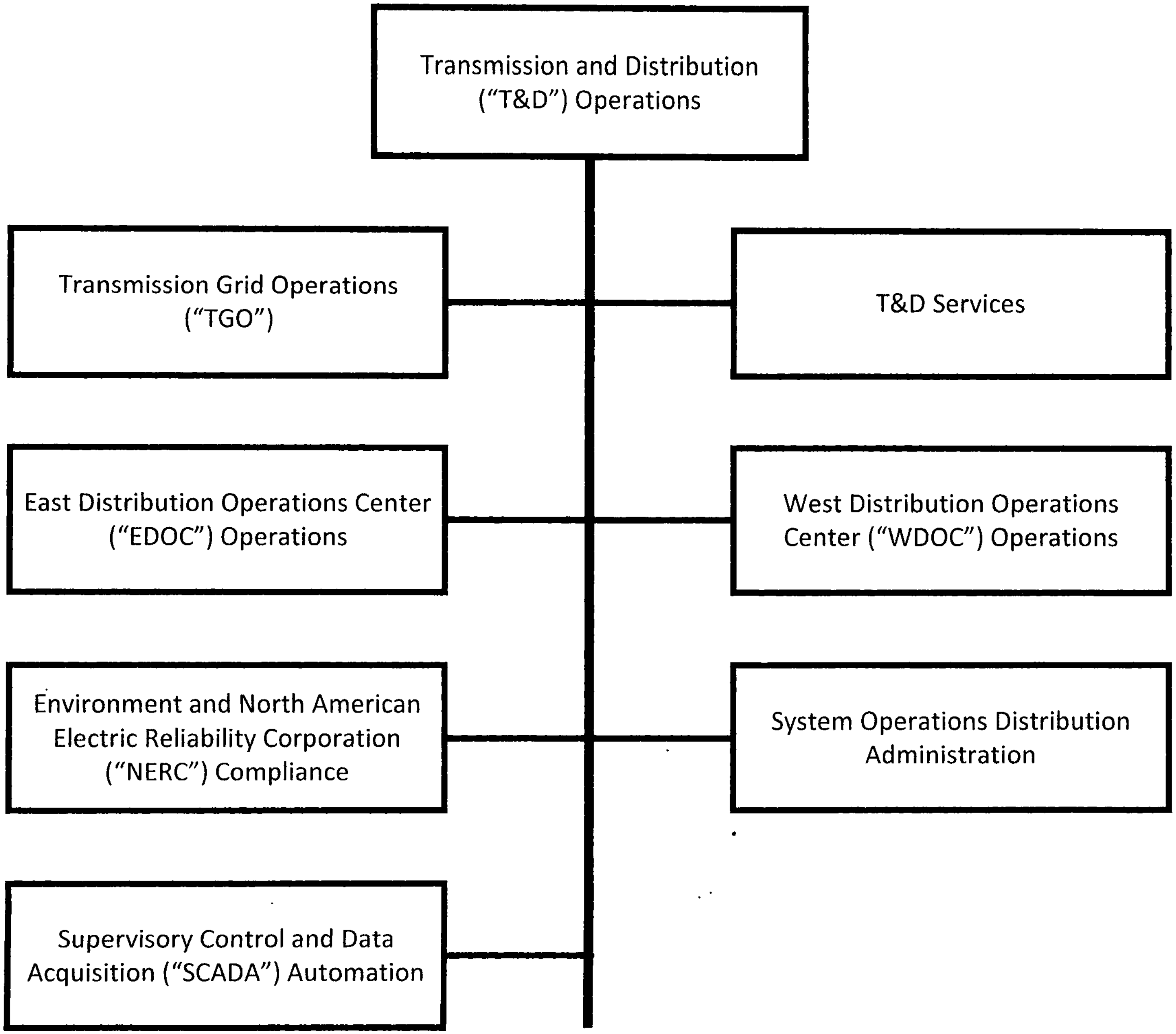


EXHIBIT CMM-1
PAGE 1 OF 1

Services Provided by Oncor's T&D Operations Organization

Group	Description of Services Provided	Group Manager & Experience
T&D Services	• Manage and provide application support and data maintenance for the TMS and DMS • Provide advanced data analytics to support real-time control room and field operations • Manage the Outage Management System • Train Transmission and Distribution Operators	Tony Bruton 21 years in Transmission Engineering, Operations, Program Management, Routing Studies, Right of Way Acquisition and Asset Investment Strategy
Transmission Grid Operations	• Ensure safe and reliable operation of Oncor's transmission grid • Coordinate with ERCOT and transmission operators • Monitor and control transmission and substation facilities • Respond to unplanned events or emergencies • Coordinate maintenance and construction activities • Perform operational studies and seasonal assessments to develop mitigation plans for specific contingencies	Collin Martin 19 years in System Protection, Transmission Operations, Transmission Grid Operations, Asset Management, Program Management, and Transmission Engineering
East Distribution Operation Center Operations West Distribution Operation Center Operations	• 24/7 control room operations of distribution system or approximately one-half of Oncor's service territory • Direct Oncor's outage restoration activities • Coordinate switching activities associated with maintenance and construction work • Work with Oncor's Transmission organization on	Boyd Greene 40 years in various positions in Distribution Operations Hagen Haentsch

Group	Description of Services Provided	Group Manager & Experience
	issues that affect both the distribution system and the transmission system • Ensure Oncor's distribution system is operated within its design parameters • Maintain records and data models • Conduct analyses following significant system events	21 years in Distribution Operations, Asset Investment Strategy, and Strategic Sourcing and Procurement

Environment and NERC Compliance	• Implement the comprehensive framework of Oncor's NERC Compliance Program, including:
	    • Facilitating standard development activities
	    • Records retention policies
	    • Compliance awareness training
	    • Coordination of self-assessments and compliance engagements with regional entities
	• Maintain compliance with all federal, state, and local environmental laws and regulations
	• Review regulatory initiatives and develop programs to comply with requirements
	• Assess environmental impacts and obtain necessary permits
	• Sustainably manage waste and recyclable materials to minimize risk
	• Coordinate self-assessments and compliance engagements with regulatory agencies
		Ray Averitt
		
		40 years in Transmission and Distribution Operations, Corporate Services, Risk Management, Environmental Compliance, and Reliability Compliance

Group	Description of Services Provided	Group Manager & Experience
System Operation Distribution Administration	• Coordinate, monitor, and report on O&M monthly budget • Perform weekly payroll analysis • Direct process improvements related to time entry and payroll • Consult on time-entry system changes	Cindy Speyrer 29 years in Accounting, Finance, Internal Audit, and Special Projects including Process Improvements
SCADA Automation	• Provide leadership, management, planning, engineering, technical, and advisory support and oversight for the Oncor Distribution Automation Program, the Distribution SCADA system, and all other distribution control systems	Jeremy Preas 15 years in Transmission and Distribution Operations, System Protection, Distribution Automation, Distribution SCADA, and Underground Networks

Oncor Actions Before, During & After Winter Storm Uri

February 6-7, 2021
Began securing additional contractors in anticipation of potential storm restoration work.

February 11, 2021
Emailed all 1,462 Large Commercial and Industrial ("LCI")-assigned accounts to inform them of the severe weather forecast and encourage them to sign up to receive ERCOT alerts

February 14, 2021
- Opened and staffed Transmission Emergency Center and System Emergency Center and increased staffing at EDOC and WDOC in preparation for the coming storm.
- Secured hotel rooms for crews, deployed contractors to Central and East Texas, and began 24-hour operations at all supply-chain, material and equipment distribution centers
- Activated DFW area staging sites with equipment and material delivered and prepared

February

Week of February 8, 2021

Upon receipt of ERCOT Operating Condition Notice:

- Identified all active outages and verified emergency restoration times
- Coordinated with ERCOT to identify and restore outages that might have impacted generation availability or had the potential to cause significant transmission system constraints
- Confirmed that cabinet heaters were operational at critical stations
- Participated in daily calls with IBM meteorologists
- Verified employee and vehicle winter preparedness
- Ordered and deployed material historically impacted by cold weather to storerooms across Oncor's service territory
- Distributed nearly 700 transformers from Oncor's central warehouse of vendor-owned inventory to Oncor service centers
- Expedited all incoming orders of transformer units and items predicted to be most heavily impacted by the weather
- Secured two material staging sites in the DFW area
- Maintained consistent communication with suppliers to ensure their availability and gauge their ability to respond to Oncor's needs during and after the event
- Increased staffing at T&D control centers to ensure personnel were ready to respond to weather conditions and ERCOT directives Additional support personnel were brought on-site, and crews were staged and ready for dispatch

EXHIBIT CMM-3
PAGE 1 OF 2

Oncor Actions Before, During & After Winter Storm Uri

ONCOR.

February 15, 2021
At 1:20 AM, ERCOT entered Energy Emergency Alert Level 3 and issued its first load-shed instruction, directing utilities to shed 1,000 MW of ERCOT load.

From 1:45 AM through 6 44 PM, ERCOT issued numerous load-shed instructions with an aggregate peak ERCOT load shed of 20,000 MW, which coincided with Oncor's peak customer outage of over 1.3 million customers.

End-of-day ERCOT load shed was 19,000 MW.

February 16, 2021
The company secured three new staging sites and deployed transformer supplies and material storm kits to these locations in Belton, Tyler, and Lufkin.

End-of-day ERCOT load shed was 15,500 MW.

February 17, 2021
Oncor's timely implementation of ERCOT's load-shed instructions from February 15-17 was critical to preventing an ERCOT system blackout.

At 11.55 pm ERCOT load shed was 0 MW.

February 18-21, 2021
Oncor continued to restore service to customers at the distribution device or feeder level, kept crucial supply chains operational, and maintained its communication with customers.

February 19, 2021
At 10:35 AM, ERCOT cancelled EEA Level 1, the Watch and Advisory for PRC, and the OCN for adverse weather conditions, returning to normal operation.

February 21, 2021
At 7·30 AM, EDOC concluded its storm restoration work

At 5.10 PM, WDOC concluded its storm restoration work.

February

Week of February 15, 2021

Oncor implemented its portion of the ERCOT load shed, restoration instructions and rotated customer outages to the extent possible. In addition:

- Communicated to all 1,462 LCI accounts to keep them informed, call for conservation, and provide Oncor media updates
- Contacted transmission-level customers, asking them to conserve energy
- Personnel worked in the field through the storm supporting load shed activities and responding to customer outages
- Sourced alternative fuel suppliers to address potential fuel scarcity issues

2022 RATE CASE
ONCOR ELECTRIC DELIVERY COMPANY LLC
WORKPAPERS FOR
THE DIRECT TESTIMONY OF
COLLIN M. MARTIN

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

INDEX TO THE DIRECT TESTIMONY
OF HAGEN HAENTSCH, WITNESS FOR
<u>ONCOR ELECTRIC DELIVERY COMPANY LLC</u>

I. POSITION AND QUALIFICATIONS 2
II. PURPOSE OF DIRECT TESTIMONY 3
III. OVERVIEW OF ADVANCED DATA ANALYTICS 3
IV. ONCOR'S GRID TECHNOLOGY INVESTMENTS AND THE RESULTING BENEFITS CONCERNING ITS USE OF ADVANCED DATA ANALYTICS 6
V. ONCOR'S USE OF ADVANCED DATA ANALYTICS TO IMPROVE SYSTEM RELIABILITY AND BENEFIT CUSTOMERS 8
   A. Enhanced Operational Decisions To Improve Reliability 10
   B. Better Investment Decisions To Avoid Outages 11
   C. Enhanced Restoration and Management 12
   D. Enhanced Storm Damage Prediction 13
   E. Targeted Vegetation Management 14
   F. Technology and Customer Engagement Advancements 15
VI. SUMMARY AND CONCLUSION 17
AFFIDAVIT 18

DIRECT TESTIMONY OF HAGEN HAENTSCH

I. POSITION AND QUALIFICATIONS

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

A. My name is Hagen Haentsch. My business address is 1201 South Sylvania Avenue, Fort Worth, Texas 76111, and I am currently employed by Oncor Electric Delivery Company LLC ("Oncor" or "Company") as Director, Distribution Operations Center – West.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. In my current role with Oncor, my organization is responsible for monitoring and operating the western half of Oncor's distribution system. In this capacity, I provide oversight to the day-to-day system operations and service restoration efforts and play a key role in system-related technology implementations. In my previous role with Oncor, I served as the Director of Asset Investment Strategy and was responsible for the development and management of Oncor's capital investment portfolio. This organization advised Oncor's executives concerning short-term investment plan execution and long-term asset investment priorities.

I have also previously been responsible for the management of Oncor's procurement, strategic sourcing, and contract management functions. I have led engagements with United States and Canadian utilities and rural electric cooperatives with a focus on reengineering asset management and supply chain processes. I began working for Oncor in 2001 as a Project Manager.

I was born and raised in Saxony, Germany. Prior to moving to the United States in 1998, I managed Alcatel's Southeast Region organization in Germany. In this role, I served commercial and industrial customers regarding voice and data enterprise networks.

I graduated from Texas Christian University in 2001 with a Master's of Business Administration and received a Certified Project Management certificate from Stanford University in 2004.

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

A. No, I have not.

II. PURPOSE OF DIRECT TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my direct testimony is to describe Oncor's advancements regarding the utilization of new and existing data sets and new advanced data analytics technologies, which have resulted in various benefits, such as improving customer service and electric system reliability.

My direct testimony was prepared by me or under my direction, supervision, or control and is, to the best of my knowledge and belief, true and correct.

III. OVERVIEW OF ADVANCED DATA ANALYTICS

Q. PLEASE PROVIDE AN OVERVIEW OF AND EXPLAIN WHAT IS MEANT BY THE TERM "ADVANCED DATA ANALYTICS."

A. "Advanced Data Analytics" refers to the capabilities to access and process very large data sets and to apply complex statistical formulas and algorithms to derive new insights for the purpose of supporting better decisions. This capability is also often referred to as "Big Data Analytics," "Artificial Intelligence," "Machine Learning," or "Cognitive Analytics."

Q. IS ADVANCED DATA ANALYTICS UTILIZED ACROSS MULTIPLE INDUSTRIES, INCLUDING THE ELECTRIC UTILITY INDUSTRY?

A. Yes, the utility industry is not spearheading the use of data analytics, but rather, is benefiting from the research and development undertaken in the technology sector and the competitive market space. As explained further in my testimony, Oncor and its customers are benefitting from these efforts.

Q. PLEASE EXPLAIN THE IMPACT OF ADVANCED DATA ANALYTICS ON THE ELECTRIC UTILITY INDUSTRY.

A. Advanced Data Analytics allows a utility to analyze internal and external data sets at a scale and complexity previously unattainable. By combining large data sets from disparate systems and applying advanced analytical algorithms, new insights can be gained that allow a utility to make faster and better operational decisions (*e.g.*, avoidance or shortening of service interruptions and improved resource and asset utilization) and interact with customers in a more meaningful, transparent, and empowering way (*e.g.*, providing improved service status information and allowing customers to make more informed decisions concerning energy usage). In short, Advanced Data Analytics is helping make utility operations and maintenance more efficient and effective.

Q. WHY HAS IT BECOME INCREASINGLY IMPORTANT FOR ELECTRIC UTILITIES TO INVEST IN AND IMPLEMENT ADVANCED DATA ANALYTICS?

A. Advanced Data Analytics has the potential to improve decisions at all management levels by allowing a utility to be more data driven and consistent in its decision-making. It also has the potential to provide more useful and empowering information to customers who desire to make operational or energy management decisions at their respective businesses or homes. These same effects would otherwise only be achievable with exponentially higher investments in human resources or services. As an analogy, just as it was important in many contexts to switch from paper or verbal communications to electronic communications, or to replace calculators and slide rules with Excel spreadsheets, well-applied Advanced Data Analytics tools and methodologies have the potential to improve the quality and speed at which decisions can be made in many functions or processes of a utility.

Q. HOW HAVE TECHNOLOGY DEVELOPMENTS LED TO THE EVOLUTION AND ADVANCEMENT OF DATA ANALYTICS?

A. In general, the development of new analytical methods such as deep learning or neural networks algorithms—combined with the continued improvements of processing power and data management capabilities—enabled the development of new tool sets and methodologies that made the computation of intensive statistical algorithms and data processing tasks feasible in a standard information technology ("Technology") environment such as Oncor's. Additionally, Oncor's Technology platform modernization efforts, combined with its advanced metering system ("AMS") investments, communication infrastructure, and distribution automation equipment, created the opportunity to create new data sets and combine existing data sets in ways that enabled Oncor to apply these newly emerging analytics tool sets and methodologies and make them comprehensible and useful.

Q. WHAT ARE SOME EXAMPLES OF TECHNOLOGY DEVELOPMENTS THAT HAVE ALLOWED DATA ANALYTICS TO ADVANCE?

A. In-memory data processing and storage, data virtualization, neural networks and machine learning algorithms, data processing and storage virtualization and containerization, Graphical Processing Unit ("GPU") programming, and application programming interfaces ("APIs") are a few examples of technology developments that have allowed data analytics to advance.

Q. HAVE TECHNOLOGY DEVELOPMENTS ASSOCIATED WITH ADVANCED DATA ANALYTICS BECOME MORE ATTAINABLE?

A. Yes. Technology developments have generally become more affordable in recent years and, therefore, more readily attainable, with the majority of products made available through the open source market or vendors targeting large-scale market adoption.

Q. HOW HAVE TECHNOLOGY DEVELOPMENTS BENEFITED ADVANCED DATA ANALYTICS?

A. Oncor's recent modernization of Technology and Smart Grid investments positioned it to access, combine, process, and visualize data in ways previously impossible or unaffordable. For example, these new advanced data processing and analytics capabilities allow Oncor to connect data from disparate systems to validate each other and improve data quality, or to detect abnormalities that have operational significance. In previous years, efforts to combine advanced meter outage data with distribution outage management system ("OMS") data for any significant portion of Oncor's grid would have been difficult and time consuming. In his testimony, Company witness Mr. Daniel E. Hall describes the integration of advanced metering and distribution outage management data.

Similarly, to display, search, and correlate graphical data elements of Oncor's distribution network map without the utilization of unconventional database technology and GPU computing would have created significantly higher resource requirements. Likewise, new deep-learning and machine-learning algorithms enabled the application of complex statistical functions to graphical imagery, creating opportunities to use satellite and aircraft images for pattern analysis that better informs Oncor's operational personnel about right-of-way conditions, such as vegetation growth or construction site preparation, making the way we maintain the grid smarter.

IV. ONCOR'S GRID TECHNOLOGY INVESTMENTS AND THE RESULTING BENEFITS CONCERNING ITS USE OF ADVANCED DATA ANALYTICS

Q. PLEASE DESCRIBE THE RELATIONSHIP BETWEEN ONCOR'S GRID TECHNOLOGY INVESTMENTS AND ITS USE OF ADVANCED DATA ANALYTICS.

A. Advanced metering, distribution supervisory control and data acquisition ("SCADA") equipment and related software applications all produce exponentially larger data sets compared to those that can be handled with conventional data management approaches. Advanced Data Analytics allows Oncor to tap into these new data sets and combine them with other existing internal or external data sets to derive new insights, allowing Oncor to make faster and superior business and operational decisions.

Q. PLEASE IDENTIFY AND DESCRIBE ONCOR'S GRID TECHNOLOGY INVESTMENTS THAT HAVE ENABLED AND INCREASED THE USE OF ADVANCED DATA ANALYTICS.

A. Over the past several years, Oncor has invested in advanced metering, a variety of SCADA-enabled distribution devices, and upgrades to its communication infrastructure. These investments have not only improved customer service and grid reliability, but also created new operational data (*e.g.*, alarms and voltage levels at the meter and SCADA measurements at feeder switch points) that can now be correlated with existing data sets (*e.g.*, outage information and substitution SCADA measurements), or even external data (*e.g.*, weather data). This ability to combine multiple, even very large data sets, provides the basis for Advanced Data Analytics and enables Oncor to make more reliable decisions and predictions.

Q. WHAT ARE EXAMPLES OF DATA THAT HAVE BECOME AVAILABLE TO ONCOR AS A RESULT OF ITS GRID TECHNOLOGY INVESTMENTS?

A. Examples of data that have become available because of Oncor's grid technology investments include distribution SCADA data, real-time meter status, and meter interval data, such as load and voltage.

Q. IS ONCOR'S USE OF ADVANCED DATA ANALYTICS LIMITED TO GRID TECHNOLOGY INVESTMENTS?

A. No, not at all. Grid technology investments alone are not sufficient to fully build a utility's advanced analytics capability, and additional actions must be taken for Oncor to best utilize new types of data made available by grid technology investments. To fully tap into the opportunities presented by new advanced analytics technologies, Oncor has invested in, and should continue to invest in: (1) re-skilling/training its analyst, engineering, and technology employee groups; (2) developing new management processes and modern technology solutions that allow data and algorithmic models to be managed securely and at an ever-increasing scale; and (3) furthering investment in software tools and platforms that can evolve as Oncor matures in this area.

Q. HOW IS ONCOR BUILDING ITS CAPACITY TO EFFICIENTLY AND EFFECTIVELY UTILIZE ADVANCED DATA ANALYTICS?

A. Oncor decided to focus its efforts on building an internal advanced analytics capability that minimizes dependency on external intellectual property and resources, and building on its existing engineering and analyst talent pool. Oncor is confident that, while Advanced Data Analytics tools and platforms will continue to decrease in cost and complexity over time, the critical institutional knowledge of Oncor's processes, equipment, and environments will not diminish regardless of technological developments. Additionally, the iterative nature of many of these analytical methods provides an inherent benefit of learning and feedback to the employees who are managing the processes or assets related to such analysis. Use of internal resources also facilitates and enhances knowledge sharing, collaboration, and informal innovation across functional boundaries within Oncor that would be impossible to achieve using external consultants and vendors. Lastly, there are synergies and compounding benefits between the majority of analytical use cases. Leveraging experiences and lessons learned flow directly into the next phase or another use case using similar data sets. Oncor's analytical capacity is increasing as these experiences build the basis for future efforts.

V. ONCOR'S USE OF ADVANCED DATA ANALYTICS TO IMPROVE SYSTEM RELIABILITY AND BENEFIT CUSTOMERS

Q. PLEASE GENERALLY EXPLAIN WHY ONCOR HAS INVESTED IN ADVANCED GRID TECHNOLOGY AND ADVANCED DATA ANALYTICS.

A. Advanced Data Analytics has improved the quality of Oncor's decision-making at all management levels and across most functional areas. Better operational and business intelligence improves immediate tactical decisions shared across front-line employees as well as major strategic decisions at the executive level. Additionally, Advanced Data Analytics allows more useful and accurate information to be shared with our customers, enabling them to make better energy management and energy sourcing decisions in the diverse and competitive marketplace.

Q. HOW HAVE ONCOR AND ITS CUSTOMERS GENERALLY BENEFITED FROM ADVANCED DATA ANALYTICS?

A. Customer interactions have become more effective by Oncor's improvement and expansion of its communication channels and content. For example, Oncor has implemented mobile applications, software interfaces for accessing consumption, and web-based service tracking tools to provide an improved customer experience and enable customers to make better, more informed decisions concerning their energy usage and service availability.

Q. PLEASE EXPLAIN HOW ADVANCED DATA ANALYTICS IS APPLIED AND HOW IT IMPACTS ONCOR'S DAY-TO-DAY OPERATIONS.

A. Improving reliability typically depends on a sound understanding of past events and causes of service interruptions. Advanced Data Analytics allows for a better understanding of true outage causes, such as failed windings in transformers, and by extension enables a more targeted and predictive approach to maintenance. Even though these concepts are not new, Advanced Data Analytics allows their use at an increased scale providing more specific predictions, which have avoided outages that were unavoidable in the past. For Oncor to have the ability to understand system conditions in near-real time allows it to provide swift and accurate responses to critical conditions that otherwise would have resulted in prolonged durations of service interruptions. These predictions and insights are made available through mobile devices and enable Oncor's front-line employees