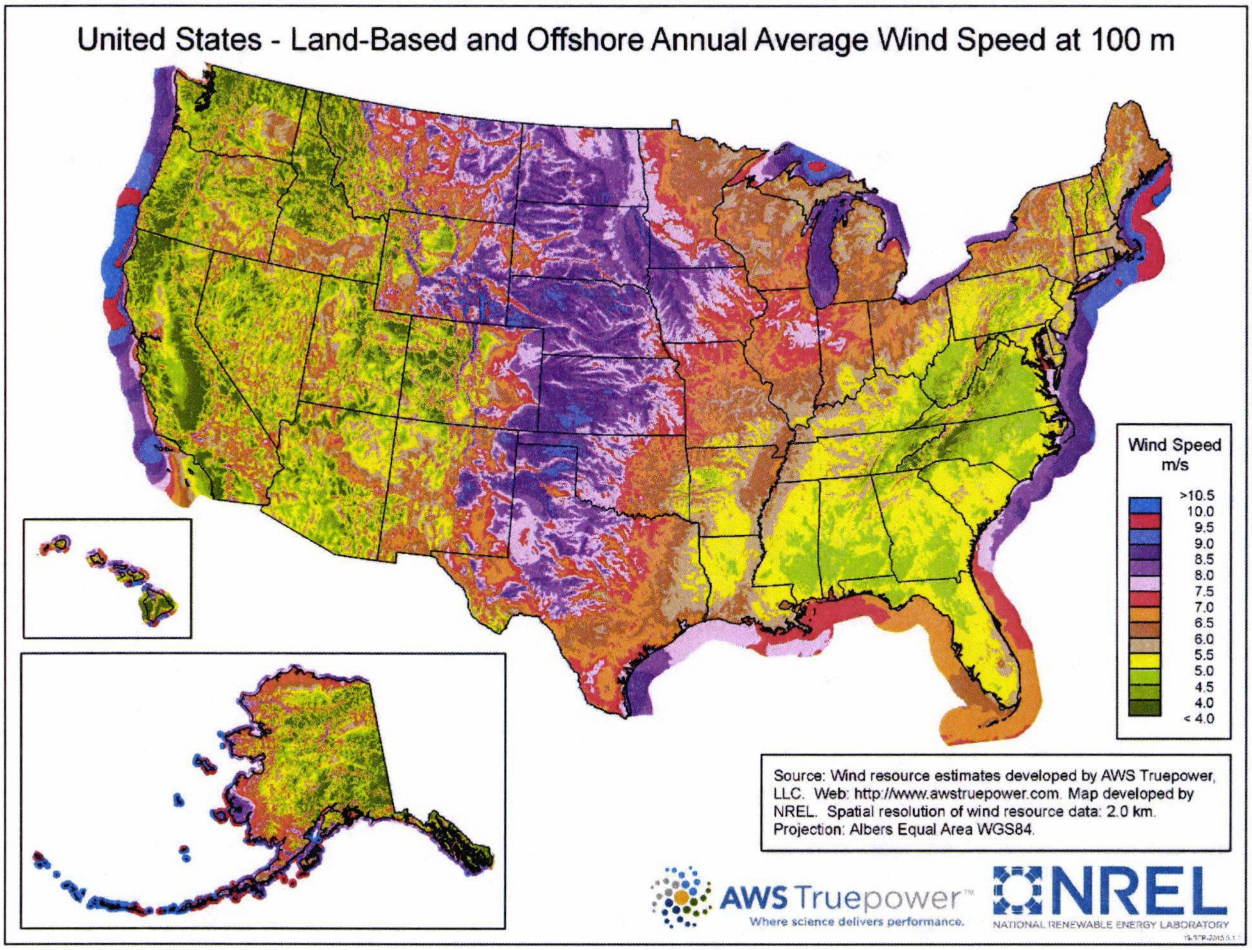

United States - Land-Based and Offshore Annual Average Wind Speed at 100 m
Wind Speed
m/s
>10.5
10.0
9.5
9.0
8.5
8.0
7.5
7.0
6.5
6.0
5.5
5.0
4.5
4.0
< 4.0
Source: Wind resource estimates developed by AWS Truepower, LLC. Web: http://www.awstruepower.com. Map developed by NREL. Spatial resolution of wind resource data: 2.0 km. Projection: Albers Equal Area WGS84.
AWS Truepower
Where science delivers performance.
NREL
NATIONAL RENEWABLE ENERGY LABORATORY

TOTAL INSTALLED CAPITAL COST

	Traverse		Maverick		Sundance		TOTAL	
PSA Purchase Price	**$**	**1,208,376,087**	**$**	**371,577,337**	**$**	**280,954,690**	**$**	**1,860,908,114**
PSA Price Adjustments								
O&M Mobilization	$	3,005,859	$	673,353	$	320,803	$	4,000,015
Capital Spare Parts	$	3,406,000	$	822,000	$	2,078,000	$	6,306,000
Power Curve Testing	$	750,000	$	-	$	-	$	750,000
Subtotal	**$**	**7,161,859**	**$**	**1,495,353**	**$**	**2,398,803**	**$**	**11,056,015**
Owner's Costs								
Owner's Costs & Overheads	$	25,050,062	$	13,252,544	$	11,475,715	$	49,778,321
Contingency	$	42,293,163	$	13,005,207	$	9,833,414	$	65,131,784
AFUDC	$	4,702,973	$	2,663,906	$	1,977,319	$	9,344,198
Subtotal	**$**	**72,046,198**	**$**	**28,921,657**	**$**	**23,286,448**	**$**	**124,254,303**
Total Wind Facility Cost	**$**	**1,287,584,144**	**$**	**401,994,347**	**$**	**306,639,941**	**$**	**1,996,218,432**

PERMITTING/STUDY STATUS

Wildlife and Habitat Assessments	Traverse	Maverick	Sundance
Tier 1-2 Site Characterization	Completed	Summer 2019	Completed
Whooping Crane Habitat Assessment	Completed	Completed	Completed
Eagle Risk Assessment	N/A	Completed	Completed
Bat Habitat Assessment	Completed	See Note 2	See Note 2
Desktop Wetlands Assessment	Completed	See Note 1	See Note 1
Tier 3 Lesser Prairie Chicken Lek Survey	N/A	See Note 1	Completed
Wetland Delineation	Summer 2019	Summer 2019	Summer 2019
Tier 3 Eagle Use Point Count Survey			
Year 1	Ongoing	Ongoing	Completed
Year 2	Winter 2019	Summer 2020	Completed
Tier 3 Raptor Migration Survey			
Year 1	N/A	Survey Complete Report in Progress	Completed
Year 2	N/A	In progress	Completed
Tier 3 Raptor Nest Survey			
Year 1	Completed	Survey Complete Report in Progress	Completed
Year 2	Completed	Spring 2020	Completed
Tier 3 Passive Bat Acoustic Survey			
Year 1	Ongoing	Completed	Completed
Year 2	Fall 2019	Completed	Completed
Year 3	N/A	Fall 2019	Completed

Local and Non-Environmental	Traverse	Maverick	Sundance
FAA			
File turbine coordinates of micro-sited layout	Fall 2019	Summer 2019	Summer 2019
OCC notification process	Spring 2020	Fall 2019	Fall 2019
County Permit			
Road Use Agreement	Summer 2020	Summer 2019	Summer 2019
County Road Crossing Agreements	Summer 2020	Fall 2019	Fall 2019
No permitting letter from county	Summer 2019	Summer 2019	Summer 2019
Local Permit			
No local permitting	N/A	N/A	N/A
SWPP Plan			
Contractor files SWPP ahead of construction	Fall 2020	Fall 2020	Fall 2019

Notes:
1) Original developer elected not to perform this study.
2) Bat Habitat Assessment not performed. Habitat issues were known and confirmed by acoustic surveys.

O&M AND CAPITAL FORECAST ($000) - Traverse

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
O&M										
O&M Services Agreement Costs										
Invenergy O&M Services Agreement[1]	$ 7,092	$ 8,016	$ 7,469	$ 7,751	$ 7,928	$ 8,028	$ 8,182	$ 8,340	$ 8,501	$ 8,666
Total O&M Service Costs	**$ 7,092**	**$ 8,016**	**$ 7,469**	**$ 7,751**	**$ 7,928**	**$ 8,028**	**$ 8,182**	**$ 8,340**	**$ 8,501**	**$ 8,666**
General Costs										
Environmental Program[2]	$ 491	$ 491	$ 491	$ 491	$ 491	$ 75	$ 75	$ 75	$ 75	$ 75
Major Maintenance/Other Parts[3]	$ 40	$ 40	$ 3,904	$ 3,982	$ 4,061	$ 4,142	$ 4,225	$ 4,310	$ 4,396	$ 4,484
Balance of Plant	$ -	$ -	$ 73	$ 74	$ 476	$ 487	$ 498	$ 508	$ 520	$ 531
Blade Maintenance Program	$ -	$ -	$ 144	$ 147	$ 150	$ 153	$ 157	$ 160	$ 164	$ 167
Substation Maintenance	$ 35	$ 36	$ 36	$ 37	$ 38	$ 39	$ 39	$ 40	$ 41	$ 42
Gearbox Oil	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 300	$ 600	$ 600
Insurance	$ 1,329	$ 1,356	$ 1,383	$ 1,411	$ 1,439	$ 1,468	$ 1,497	$ 1,527	$ 1,557	$ 1,589
Land Lease	$ 4,214	$ 4,146	$ 4,146	$ 4,146	$ 4,146	$ 4,146	$ 4,146	$ 4,146	$ 4,146	$ 4,146
Property Tax	$ 11,840	$ 14,321	$ 15,678	$ 16,294	$ 16,464	$ 16,092	$ 15,466	$ 15,074	$ 14,501	$ 13,928
Total General Costs	**$ 17,949**	**$ 20,390**	**$ 25,855**	**$ 26,582**	**$ 27,265**	**$ 26,602**	**$ 26,104**	**$ 26,141**	**$ 26,001**	**$ 25,563**
SWEPCO / PSO Costs										
Forecasting Services	$ 10	$ 10	$ 10	$ 11	$ 11	$ 11	$ 11	$ 11	$ 12	$ 12
AEPSC Support (Engr, Legal, Tax)	$ 60	$ 61	$ 62	$ 64	$ 65	$ 66	$ 68	$ 69	$ 70	$ 72
AEPSC Overheads / Allocations	$ 39	$ 40	$ 41	$ 41	$ 42	$ 43	$ 44	$ 45	$ 46	$ 47
On-Going IT / Telecom Costs	$ 160	$ 163	$ 166	$ 170	$ 173	$ 177	$ 180	$ 184	$ 187	$ 191
AEP Site Labor[4]	$ 245	$ 209	$ 213	$ 217	$ 222	$ 226	$ 231	$ 235	$ 240	$ 245
Misc. Expenses	$ 100	$ 102	$ 104	$ 106	$ 108	$ 110	$ 113	$ 115	$ 117	$ 120
SWEPCO / PSO Costs Total	**$ 614**	**$ 585**	**$ 597**	**$ 609**	**$ 621**	**$ 634**	**$ 646**	**$ 659**	**$ 672**	**$ 686**
Total O&M	**$ 25,655**	**$ 28,991**	**$ 33,920**	**$ 34,942**	**$ 35,814**	**$ 35,264**	**$ 34,932**	**$ 35,141**	**$ 35,174**	**$ 34,914**
CAPITAL										
Environmental Program[2]	$ 250	$ 609	$ 359	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Major Maintenance / Other Parts[3]	$ -	$ -	$ 5,855	$ 5,972	$ 6,092	$ 6,214	$ 6,338	$ 6,465	$ 6,594	$ 6,726
Total Capital Costs	**$ 250**	**$ 609**	**$ 6,214**	**$ 5,972**	**$ 6,092**	**$ 6,214**	**$ 6,338**	**$ 6,465**	**$ 6,594**	**$ 6,726**
Total Costs (O&M and Capital)	**$ 25,905**	**$ 29,600**	**$ 40,135**	**$ 40,915**	**$ 41,906**	**$ 41,477**	**$ 41,270**	**$ 41,606**	**$ 41,768**	**$ 41,640**

Notes:

1) O&M Services Agreement includes routine operations and maintenance of the facilities (including site operators), monitoring, dispatch and other duties per the agreement.
2) Environmental Program costs include avian (or other) studies and potential future mitigation costs.
3) Major Maintenance/Other parts includes all parts replaced under the Invenergy O&M Services Agreement and major maintenance parts and labor for activities such as blade replacements, gearbox repairs, and switchgear repairs.
4) AEP Site Labor costs includes a PSO/SWEPCO Plant Manager, training costs for the Plant Manager, and associated vehicle expenses.

O&M AND CAPITAL FORECAST ($000) - Maverick

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
O&M										
O&M Services Agreement Costs										
Invenergy O&M Services Agreement[1]	$ 2,292	$ 2,568	$ 2,443	$ 2,497	$ 2,529	$ 2,576	$ 2,625	$ 2,674	$ 2,724	$ 2,784
Total O&M Service Costs	**$ 2,292**	**$ 2,568**	**$ 2,443**	**$ 2,497**	**$ 2,529**	**$ 2,576**	**$ 2,625**	**$ 2,674**	**$ 2,724**	**$ 2,784**
General Costs										
Environmental Program[2]	$ 164	$ 164	$ 164	$ 164	$ 164	$ 50	$ 50	$ 50	$ 50	$ 50
Major Maintenance/Other Parts[3]	$ 15	$ 15	$ 1,120	$ 1,142	$ 1,165	$ 1,188	$ 1,212	$ 1,236	$ 1,261	$ 1,286
Balance of Plant	$ -	$ -	$ 21	$ 21	$ 137	$ 140	$ 143	$ 146	$ 149	$ 152
Blade Maintenance Program	$ -	$ -	$ 41	$ 42	$ 43	$ 44	$ 45	$ 46	$ 47	$ 48
Substation Maintenance	$ 20	$ 20	$ 21	$ 21	$ 22	$ 22	$ 23	$ 23	$ 23	$ 24
Gearbox Oil	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 85	$ 170	$ 170
Insurance	$ 409	$ 417	$ 425	$ 434	$ 442	$ 451	$ 460	$ 470	$ 479	$ 488
Land Lease	$ 1,433	$ 1,433	$ 1,433	$ 1,433	$ 1,433	$ 1,433	$ 1,433	$ 1,433	$ 1,433	$ 1,433
Property Tax	$ 3,698	$ 4,473	$ 4,897	$ 5,089	$ 5,143	$ 5,026	$ 4,831	$ 4,709	$ 4,530	$ 4,351
Total General Costs	**$ 5,739**	**$ 6,522**	**$ 8,122**	**$ 8,347**	**$ 8,548**	**$ 8,355**	**$ 8,197**	**$ 8,197**	**$ 8,142**	**$ 8,003**
SWEPCO / PSO Costs										
Forecasting Services	$ 10	$ 10	$ 10	$ 11	$ 11	$ 11	$ 11	$ 11	$ 12	$ 12
AEPSC Support (Engr, Legal, Tax)	$ 40	$ 41	$ 42	$ 42	$ 43	$ 44	$ 45	$ 46	$ 47	$ 48
AEPSC Overheads / Allocations	$ 26	$ 27	$ 27	$ 28	$ 28	$ 29	$ 29	$ 30	$ 30	$ 31
On-Going IT / Telecom Costs	$ 160	$ 163	$ 166	$ 170	$ 173	$ 177	$ 180	$ 184	$ 187	$ 191
AEP Site Labor[4]	$ 123	$ 105	$ 107	$ 109	$ 111	$ 114	$ 116	$ 118	$ 121	$ 123
Misc. Expenses	$ 75	$ 77	$ 78	$ 80	$ 81	$ 83	$ 84	$ 86	$ 88	$ 90
SWEPCO / PSO Costs Total	**$ 434**	**$ 422**	**$ 431**	**$ 439**	**$ 448**	**$ 457**	**$ 466**	**$ 475**	**$ 485**	**$ 495**
Total O&M	**$ 8,465**	**$ 9,513**	**$ 10,995**	**$ 11,283**	**$ 11,525**	**$ 11,388**	**$ 11,287**	**$ 11,346**	**$ 11,351**	**$ 11,281**
CAPITAL										
Environmental Program[2]	$ -	$ 155	$ 155	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Major Maintenance / Other Parts[3]	$ -	$ -	$ 1,679	$ 1,713	$ 1,747	$ 1,782	$ 1,818	$ 1,854	$ 1,891	$ 1,929
Total Capital Costs	**$ -**	**$ 155**	**$ 1,834**	**$ 1,713**	**$ 1,747**	**$ 1,782**	**$ 1,818**	**$ 1,854**	**$ 1,891**	**$ 1,929**
Total Costs (O&M and Capital)	**$ 8,465**	**$ 9,667**	**$ 12,829**	**$ 12,996**	**$ 13,272**	**$ 13,170**	**$ 13,105**	**$ 13,201**	**$ 13,242**	**$ 13,211**

Notes:

1) O&M Services Agreement includes routine operations and maintenance of the facilities (including site operators), monitoring, dispatch and other duties per the agreement.
2) Environmental Program costs include avian (or other) studies and potential future mitigation costs.
3) Major Maintenance/Other parts includes all parts replaced under the Invenergy O&M Services Agreement and major maintenance parts and labor for activities such as blade replacements, gearbox repairs, and switchgear repairs.
4) AEP Site Labor costs includes a PSO/SWEPCO Plant Manager to be be shared with the Sundance facility, training costs for the Plant Manager, and associated vehicle expenses.

O&M AND CAPITAL FORECAST ($000) - Sundance

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
O&M										
O&M Services Agreement Costs										
Invenergy O&M Services Agreement[1]	$ 1,568	$ 1,756	$ 1,648	$ 1,708	$ 1,746	$ 1,768	$ 1,801	$ 1,835	$ 1,869	$ 1,904
Total O&M Service Costs	**$ 1,568**	**$ 1,756**	**$ 1,648**	**$ 1,708**	**$ 1,746**	**$ 1,768**	**$ 1,801**	**$ 1,835**	**$ 1,869**	**$ 1,904**
General Costs										
Environmental Program[2]	$ 126	$ 126	$ 126	$ 126	$ 126	$ 50	$ 50	$ 50	$ 50	$ 50
Major Maintenance/Other Parts[3]	$ 10	$ 10	$ 767	$ 783	$ 798	$ 814	$ 831	$ 847	$ 864	$ 881
Balance of Plant	$ -	$ -	$ 14	$ 15	$ 15	$ 96	$ 98	$ 100	$ 102	$ 104
Blade Maintenance Program	$ -	$ -	$ 28	$ 29	$ 29	$ 30	$ 31	$ 31	$ 32	$ 33
Substation Maintenance	$ 20	$ 20	$ 21	$ 21	$ 22	$ 22	$ 23	$ 23	$ 23	$ 24
Gearbox Oil	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 60	$ 120	$ 120
Insurance	$ 309	$ 315	$ 322	$ 328	$ 335	$ 341	$ 348	$ 355	$ 362	$ 369
Land Lease	$ 1,417	$ 1,417	$ 1,417	$ 1,417	$ 1,417	$ 1,417	$ 1,417	$ 1,417	$ 1,417	$ 1,417
Property Tax	$ 2,524	$ 2,821	$ 3,413	$ 3,736	$ 3,882	$ 3,923	$ 3,834	$ 3,685	$ 3,592	$ 3,455
Total General Costs	**$ 4,406**	**$ 4,710**	**$ 6,108**	**$ 6,454**	**$ 6,625**	**$ 6,693**	**$ 6,631**	**$ 6,569**	**$ 6,563**	**$ 6,454**
SWEPCO / PSO Costs										
Forecasting Services	$ 10	$ 10	$ 10	$ 11	$ 11	$ 11	$ 11	$ 11	$ 12	$ 12
AEPSC Support (Engr, Legal, Tax)	$ 40	$ 41	$ 42	$ 42	$ 43	$ 44	$ 45	$ 46	$ 47	$ 48
AEPSC Overheads / Allocations	$ 26	$ 27	$ 27	$ 28	$ 28	$ 29	$ 29	$ 30	$ 30	$ 31
On-Going IT / Telecom Costs	$ 160	$ 163	$ 166	$ 170	$ 173	$ 177	$ 180	$ 184	$ 187	$ 191
AEP Site Labor[4]	$ 123	$ 105	$ 107	$ 109	$ 111	$ 114	$ 116	$ 118	$ 121	$ 123
Misc. Expenses	$ 50	$ 51	$ 52	$ 53	$ 54	$ 55	$ 56	$ 57	$ 59	$ 60
SWEPCO / PSO Costs Total	**$ 409**	**$ 397**	**$ 405**	**$ 413**	**$ 421**	**$ 429**	**$ 438**	**$ 447**	**$ 456**	**$ 465**
Total O&M	**$ 6,382**	**$ 6,863**	**$ 8,161**	**$ 8,575**	**$ 8,791**	**$ 8,890**	**$ 8,870**	**$ 8,850**	**$ 8,887**	**$ 8,823**
CAPITAL										
Environmental Program[2]	$ -	$ 180	$ 180	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Major Maintenance / Other Parts[3]	$ -	$ -	$ 1,151	$ 1,174	$ 1,198	$ 1,221	$ 1,246	$ 1,271	$ 1,296	$ 1,322
Total Capital Costs	**$ -**	**$ 180**	**$ 1,331**	**$ 1,174**	**$ 1,198**	**$ 1,221**	**$ 1,246**	**$ 1,271**	**$ 1,296**	**$ 1,322**
Total Costs (O&M and Capital)	**$ 6,382**	**$ 7,043**	**$ 9,492**	**$ 9,749**	**$ 9,989**	**$ 10,112**	**$ 10,116**	**$ 10,121**	**$ 10,184**	**$ 10,145**

Notes:

1) O&M Services Agreement includes routine operations and maintenance of the facilities (including site operators), monitoring, dispatch and other duties per the agreement.
2) Environmental Program costs include avian (or other) studies and potential future mitigation costs.
3) Major Maintenance/Other parts includes all parts replaced under the Invenergy O&M Services Agreement and major maintenance parts and labor for activities such as blade replacements, gearbox repairs, and switchgear repairs.
4) AEP Site Labor costs includes a PSO/SWEPCO Plant Manager to be be shared with the Maverick facility, training costs for the Plant Manager, and associated vehicle expenses.

PUC DOCKET NO. __________

PUBLIC UTILITY COMMISSION OF TEXAS

APPLICATION OF

SOUTHWESTERN ELECTRIC POWER COMPANY

FOR CERTIFICATE OF CONVENIENCE AND NECESSITY

AUTHORIZATION AND RELATED RELIEF FOR

THE ACQUISITION OF WIND GENERATION FACILITIES

DIRECT TESTIMONY OF

KARL R. BLETZACKER

FOR

SOUTHWESTERN ELECTRIC POWER COMPANY

JULY 15, 2019

TESTIMONY INDEX

SECTION | PAGE

I. INTRODUCTION

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

A. My name is Karl R. Bletzacker. My position is Director, Fundamentals Analysis, American Electric Power Service Corporation (AEPSC). AEPSC supplies engineering, financial, accounting, planning and advisory services to the electric operating companies of American Electric Power Company, Inc. (AEP), including Southwestern Electric Power Company (SWEPCO or the Company). My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE?

A. I received a BSMEng degree from The Ohio State University in 1980 and have nearly forty years of energy industry experience, which includes petroleum engineering and the management of the purchasing, interstate transmission, and distribution of natural gas and power to both regulated and unregulated consumers. Before joining AEP, I implemented risk management strategies using New York Mercantile Exchange (NYMEX) and over-the-counter natural gas futures, swaps, and options since the NYMEX natural gas contract was first offered in June of 1990. I also purchased short- and long-term natural gas supply from major and independent producers and marketing companies and I monetized arbitrage opportunities using NYMEX futures contracts, local and contract storage, pipeline imbalances and local distribution company banks. As Vice-President and Chief Operating Officer of National Gas & Oil Company (a publicly-traded Ohio natural gas utility) and Licking Rural Electric Cooperative (an Ohio electric cooperative), I was responsible for the natural gas pricing and risk management policies that ensured reliable delivery and managed customers' exposure to volatile commodity prices. As the North American Manager of Energy Procurement for Honda of America Mfg., Inc., I implemented hedging strategies utilizing NYMEX natural gas futures contracts and operated a natural gas supply pool for the benefit of Honda and its suppliers in North America. Additionally, I served as Vice-Chairman of the Industrial Energy Users-Ohio, which is an organization of large Ohio energy consumers that spend collectively over $3 billion per year on electricity and natural gas for their plants and facilities and whose members employ over 250,000. I joined AEPSC in 2005 to focus on the creation of long-term North American energy market forecasts primarily to support the integrated resource and strategic planning of its operating companies.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN PROCEEDINGS BEFORE REGULATORY BODIES?

A. Yes. I have presented testimony on behalf of AEP operating companies and others in Texas, Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Virginia, and West Virginia.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I sponsor the Long-Term North American Energy Market Forecast ("Fundamentals Forecast") utilized by Company witnesses Torpey and Sheilendranath as a basis for certain elements of the analyses they performed, which are described in their testimony. I describe how the Fundamentals Forecast is derived and, in particular, the basis for the natural gas, electric generation energy and capacity, and CO_2 burden forecasts included in the Fundamentals Forecast. Further, I illustrate other natural gas price forecasts as a source of comparison to the Company's Fundamentals Forecast. Finally, based on a break-even Southwest Power Pool (SPP) power price provided by Company witness Torpey for the wind facilities the Company proposes to acquire in this case ("Selected Wind Facilities"), I calculate a break-even cost for natural gas.

III. FUNDAMENTALS FORECAST

Q. WHAT IS AEP'S FUNDAMENTALS FORECAST?

A. The Fundamentals Forecast is a long-term, weather-normalized commodity market forecast. It is not created to meet a specific regulatory need in a particular jurisdiction; rather, it is made available to AEPSC and all AEP operating companies after completion. It is used for purposes such as resource planning, capital improvement analyses, fixed asset impairment accounting, strategic planning and others. These projections cover the electricity market within the Eastern Interconnect (which includes SPP), the Electric Reliability Council of Texas (ERCOT) and the Western Electricity Coordinating Council (WECC). The Fundamentals Forecast includes: 1) hourly, monthly and annual regional power prices (in both nominal and real dollars); 2) prices for various qualities of Central Appalachian (CAPP), Northern Appalachian (NAPP), Illinois Basin (ILB), Powder River Basin (PRB), and Colorado coals; 3) monthly and annual locational natural gas prices, including the benchmark Henry Hub; 4) nuclear fuel prices; 5) SO_2, NOx, and CO_2 burden values; 6) locational implied heat rates; 7) electric generation capacity values; 8) renewable energy subsidies; and 9) inflation factors, among others.

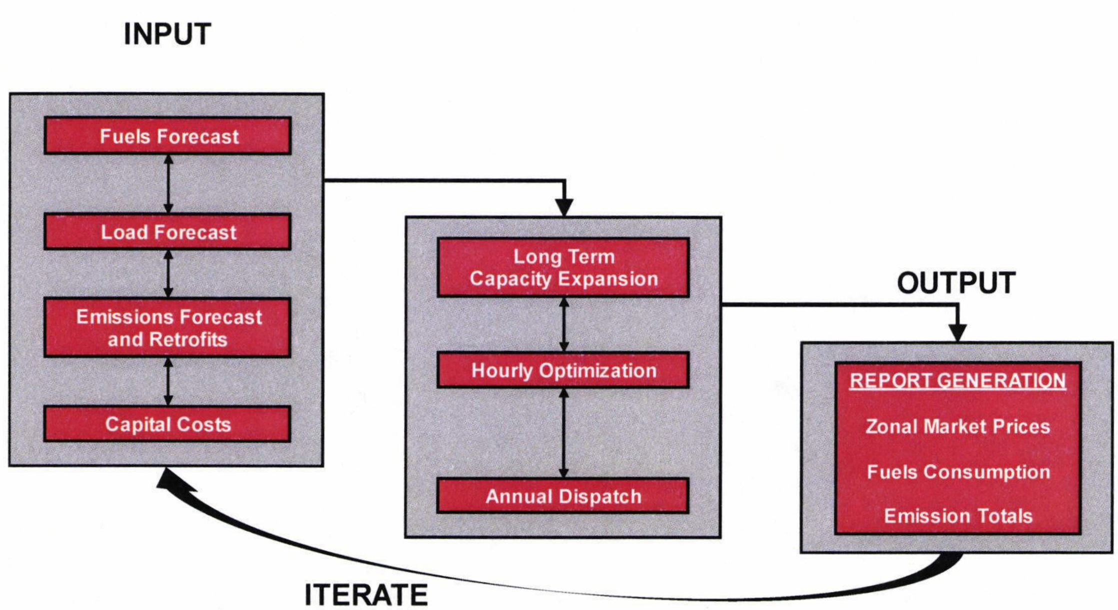
To complement the Base Case Fundamentals Forecast, four associated cases were also created; the Lower Band, Upper Band, Base No Carbon and Lower Band No Carbon cases. The associated cases were designed and generated to define a plausible range of outcomes surrounding the Base Case Fundamentals Forecast. The Lower and Upper Band forecasts consider lower and higher North American demand for electric generation and fuels and, consequently, lower and higher fuels prices, respectively. Nominally, fossil fuel prices vary one standard deviation above and below Base Case values. The Base No Carbon and Lower Band No Carbon cases assume there will be no regulations limiting CO_2 emissions throughout the entire forecast period.

Q. WHAT TOOLS DID YOU USE TO DEVELOP THE FUNDAMENTALS FORECAST?

A. The primary tool used for the development of the North American long-term energy market pricing forecasts is the Aurora energy market simulation model. It iteratively generates zonal, but not company-specific, long-term capacity expansion plans, annual energy dispatch, fuel burns and emission totals from inputs including fuel, load, emissions and capital costs, among others. Ultimately, Aurora creates a weather-normalized, long-term forecast of the market in which a utility would be operating. AEPSC also has ample energy market research information available for its reference, which includes third-party consultants, industry groups, governmental agencies, trade press, investment community, AEP-internal expertise, various stakeholders, and others.

Although no exact forecast inputs from these sources of energy market research information are utilized, an in-depth assessment of this research information can yield, among other things, an indication of the supply, demand, and price relationship (price elasticity) over a period of time. This price elasticity, when applied to the Aurora-derived natural gas fuel consumption, yields a corresponding change in natural gas prices – which is recycled through the Aurora model iteratively until the change in natural gas fuel consumption for the electric generation sector is *de minimis*. Figure 1 illustrates that any changes in input assumptions must be iteratively processed through Aurora to determine a new merit order of dispatch. It is this new merit order of dispatch that takes into account the effect of operating conditions across North America and, in turn, ultimately determines zonal energy market prices.

Figure 1



Q. WHY IS IT IMPORTANT TO RECOGNIZE THAT THE FUNDAMENTALS FORECAST IS WEATHER-NORMALIZED?

A. The Fundamentals Forecast is a long-term, weather-normalized energy market forecast because there is the credible modeling expectation that each forecast-year experiences 30-year average heating and cooling degree days. In fact, actual weather can deviate dramatically. The combination of both heating degree day departure from normal and above- or below-normal natural gas storage inventory levels are primary factors affecting any deviation from weather-normalized values. Warmer-than-normal winters result in reduced natural gas demand and materially depressed natural gas prices. Understandably, the Polar Vortex winter of 2013-2014 had the opposite effects. When comparing actual results to a weather-normalized forecast, it is imperative to account for these impacts.

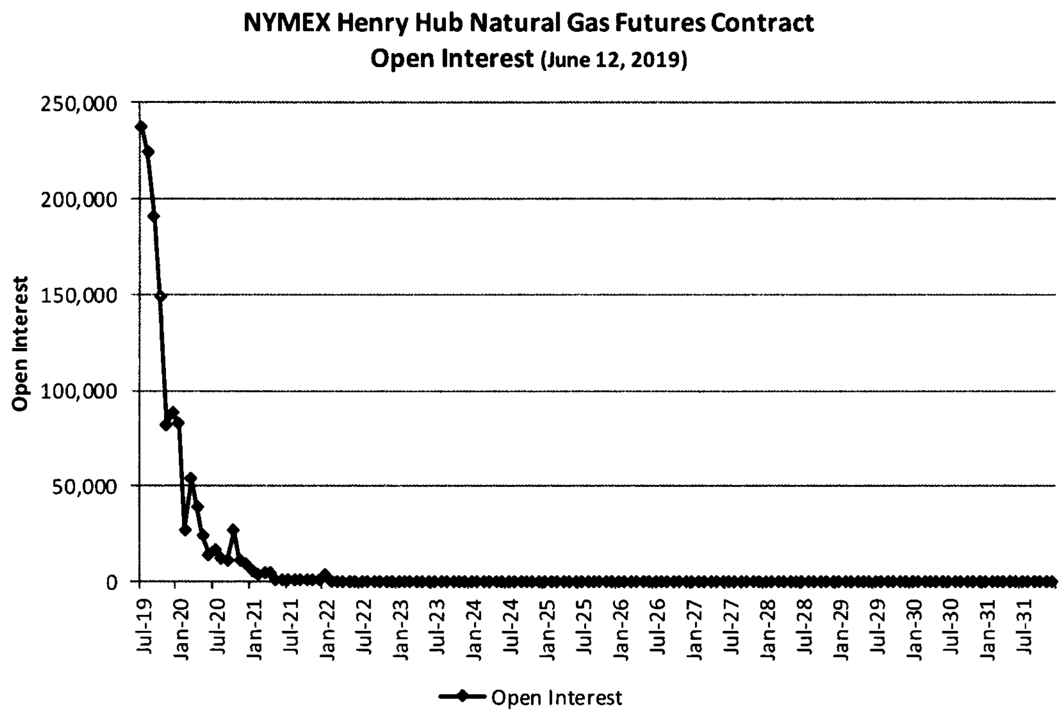
Q. WOULD YOU EXPAND ON OTHER DETAILS ABOUT THE AURORA ENERGY MARKET SIMULATION MODEL?

A. Yes. The Aurora energy market simulation model is widely used by utilities for integrated resource and transmission planning, power cost analysis and detailed generator evaluation. The database includes approximately 25,000 electric generating facilities in the contiguous United States, Canada, and Baja Mexico. These generating facilities include wind, solar, biomass, nuclear, coal, natural gas, and oil. A licensed online data provider, ABB Velocity Suite, provides up-to-date information on markets, entities and transactions along with the operating characteristics of each generating facility, which are subsequently exported to the Aurora energy market simulation model.

Q. WOULD IT BE REASONABLE TO RELY UPON NYMEX FUTURES CONTRACT PRICING IN LIEU OF A FUNDAMENTALS FORECAST FOR LONG-TERM CORPORATE PLANNING PURPOSES?

A. No. NYMEX energy-complex futures contract prices are not a reliable forecast of future, weather-normalized, long-term energy market prices. The total number of futures contracts held by market participants (*i.e.*, Open Interest) is extremely low, or zero, for NYMEX natural gas futures beyond the near term (less than two years) as illustrated in Figure 2. Furthermore, price propositions shown for this period of little or no open interest may not reflect actual NYMEX transactions, and should any attempt be made to purchase natural gas futures contracts in this period, the increased demand would likely run up prices. In addition to the illiquidity of the NYMEX natural gas futures contract beyond the near term, NYMEX natural gas futures contracts <u>are not available at all</u> beyond the next twelve years. The Company's model-driven natural gas price forecasts extend more than thirty years.

Figure 2



Q. WHY ARE NATURAL GAS PRICES IMPORTANT IN A FUNDAMENTALS ANALYSIS?

A. Natural gas prices are important because fuel prices are a key component in determining the supply stack, or merit order, for the dispatch of generating units. Generating units with the lowest variable operating cost are the first to dispatch and plants with incrementally higher variable operating cost are called upon sequentially as electricity demand increases. Although the latest vintage of natural gas electric generators is more efficient, volatile gas prices can quickly advantage or disadvantage them relative to other generation options. While natural gas prices are most often presented at the benchmark Henry Hub located in Erath, Louisiana, the Fundamentals

Forecast recognizes and projects natural gas prices at locations all across the contiguous United States.

Q. WHY IS IT IMPORTANT TO RECOGNIZE THE LOCATIONAL VALUE OF NATURAL GAS?

A. The locational value of natural gas (expressed either as a specific gas price or a price differential to the Henry Hub) can and does vary widely across North America. Generally, natural gas prices are lower near production areas and reduced further in areas with constrained exit pipeline capacity. For example, natural gas values at the west Texas Waha Hub (heavily influenced by prolific, and export-constrained, Permian Basin shale production) are not directly comparable to natural gas values within the areas of SPP in which AEP generation (owned by Public Services Company of Oklahoma and SWEPCO) operates.

Q. WHAT IS THE IMPACT OF A POTENTIAL CO_2 BURDEN ON THE FUNDAMENTALS FORECAST?

A. A CO_2 emission burden would adversely affect the cost of electricity generated by fossil fuels - along with emission rates and implementation timing. CO_2 regulations would also affect fuel markets, *e.g.,* an increase in natural gas consumption will result in increased natural gas prices. The direct effect of a $10 per metric ton allowance price for a coal plant is an approximate $10 per MWh increase in plant operating costs. And likewise, the impact of a $10 per metric ton allowance price for a natural gas-fired combined cycle plant is an approximate $4 per MWh increase in plant operating costs. Relative to fossil fuels, wind-generated power becomes more valuable because it has no CO_2 emission burden.

Q. WHAT ARE THE SALIENT FEATURES OF YOUR MOST RECENT FUNDAMENTALS FORECAST?

A. Natural Gas. Figure 3 illustrates the most recent natural gas price forecast for the Base, High Band, Low Band, Base No Carbon and Low Band No Carbon cases at the benchmark Henry Hub. The Fundamentals Forecast recognizes the balance between long-term increase in demand (including the expanding role of natural gas for electric generation and the prospect of liquefied natural gas exports) and the likelihood of cost-effective advances in shale-directed drilling and completion techniques. Abundant, relatively low-cost natural gas reserves and productive capacity will continue to grow domestically and globally as shale gas extraction technology becomes more widespread. Over the long term, natural gas pipeline capacity is expected to keep pace with the evolving locations of supply and consumption as the extensive domestic natural gas transportation infrastructure is sufficiently robust to overcome constraints through existing capacity expansions, flow reversals, and new construction.

Figure 3

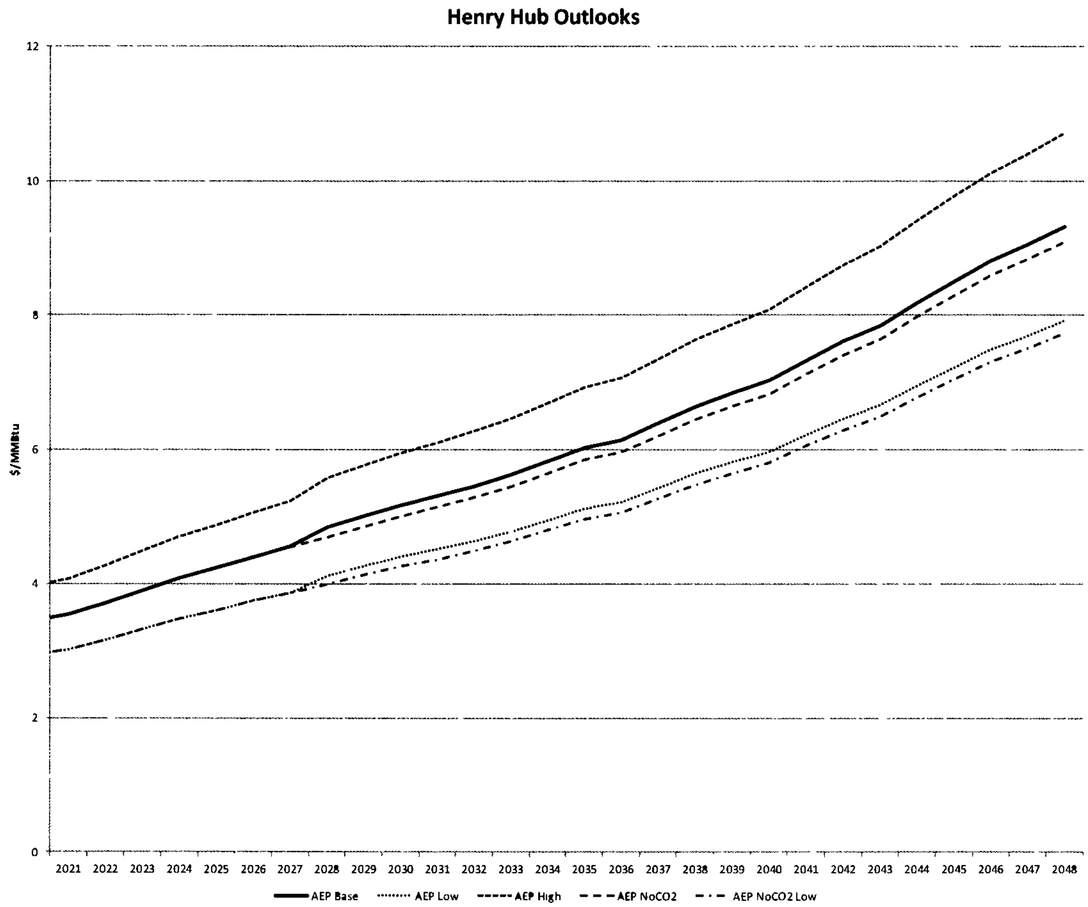
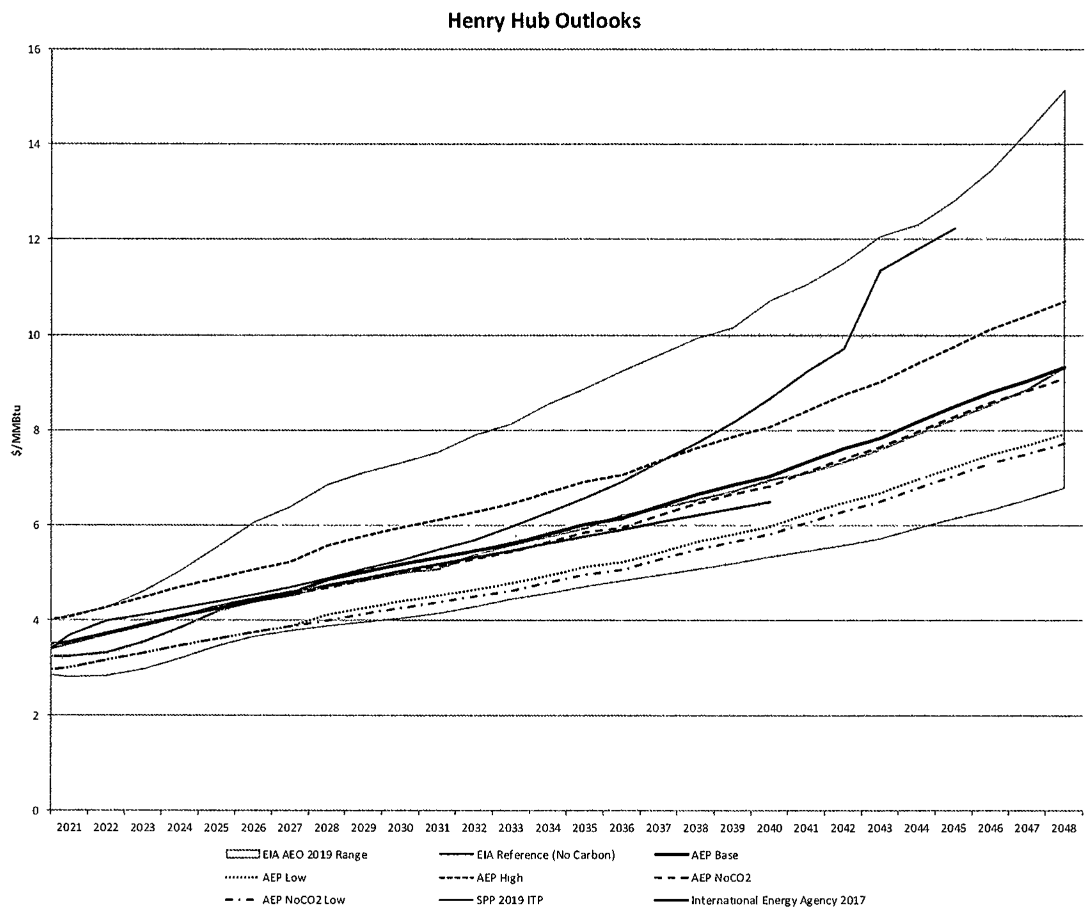


Figure 4 compares the Fundamentals Forecast Henry Hub natural gas price cases with other contemporaneous forecasts including the Energy Information Administration's (EIA's) 2019 Annual Energy Outlook, the International Energy Agency's (IEA's) 2017 Current Policies Forecast and SPP's 2019 Integrated Transmission Planning Forecast. The EIA (a part of the U.S. Department of Energy) collects, analyzes, and disseminates independent and impartial energy information to promote sound policymaking, efficient markets, and public understanding of energy and its interaction with the economy and the environment. In addition to their Reference (No Carbon) Case, the

EIA presents six plausible Side Cases represented by the shaded area. This figure shows, beyond 2037, SPP's 2019 Integrated Transmission Planning Forecast rises well above the High Fundamentals Forecast while the IEA 2017 Current Policies and the EIA 2019 Annual Energy Outlook forecasts, through the entire period, are quite similar to the Company's Fundamentals Forecast's Base Case.

Figure 4



CO$_2$ Mitigation. The 2019 Fundamentals Forecast employed a CO$_2$ dispatch burden on all existing fossil fuel-fired generating units that escalates 3.5% per annum from $15 per ton commencing in 2028. This CO$_2$ dispatch burden is less stringent than, and not intended to achieve, the national mass-based emission targets similar to those previously proposed (and now withdrawn) in the Clean Power Plan.

Q. DO RECENT LOW NATURAL GAS PRICES INDICATE THAT PRICES WILL BE LOW FOR A LONG TIME?

A. No, not necessarily. Natural gas prices can deviate from forecasted values for extended periods due to a variety of reasons, including abnormal weather and force majeure situations such as hurricanes Katrina and Rita. As addressed earlier, actual heating- and cooling-season weather can deviate dramatically from normal. Warmer than normal winters result in less gas demand and less storage refill demand in the following summer with correspondingly discounted natural gas prices. This is exactly what the U.S. experienced in the winters of 2011-2012, 2015-2016 and 2016-2017 (the second, third and fourth warmest winters since 1895, respectively), which resulted in natural gas spot prices that were significantly lower than weather-normal values.

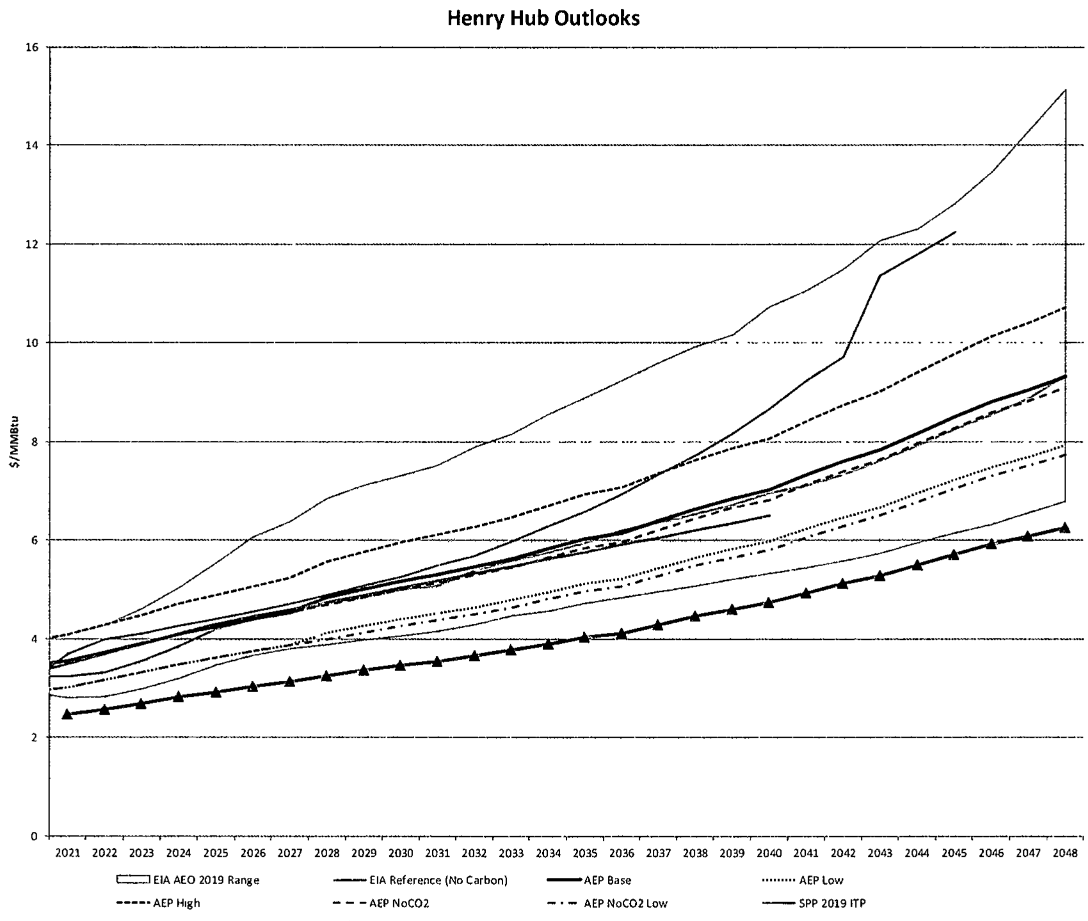
IV. SELECTED WIND FACILITIES BREAK-EVEN NATURAL GAS PRICE EVALUATION

Q. PLEASE DESCRIBE THE BREAK-EVEN NATURAL GAS PRICE EVALUATION FOR THE SELECTED WIND FACILITIES.

A. The break-even natural gas price evaluation yielded the analogous Henry Hub natural gas prices implied by the SPP electric energy prices as provided by Company witness

Torpey. Figure 5 illustrates that the Selected Wind Facilities break-even Henry Hub natural gas prices are positioned well below all of the Company's Fundamentals Forecasts and other publicly available forecasts.

Figure 5



Q. WHAT METHOD DID YOU USE TO PERFORM THE SELECTED WIND FACILITIES BREAK-EVEN NATURAL GAS PRICE EVALUATION?

A. Please refer to Company witness Torpey's Direct Testimony for the derivation of the Company-specific Break-Even SPP electric power prices. Forecasted power price divided by forecasted natural gas price yields the Implied Heat Rate (also known as the break-even natural gas market heat rate). Only a natural gas generator with an operating heat rate (a measure of unit efficiency expressed in mmBtu/MWh) below the Implied Heat Rate can be profitable by burning natural gas to generate power. Therefore, dividing Company-specific Break-Even power prices ($/MWh) by the Implied Heat Rate (mmBtu/MWh), taken from the comparable Low No Carbon Fundamentals Forecast case, resulted in the appropriate Break-Even natural gas price ($/mmBtu).

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

PUC DOCKET NO. _____

PUBLIC UTILITY COMMISSION OF TEXAS

APPLICATION OF

SOUTHWESTERN ELECTRIC POWER COMPANY

FOR CERTIFICATE OF CONVENIENCE AND NECESSITY

AUTHORIZATION AND RELATED RELIEF FOR

THE ACQUISITION OF WIND GENERATION FACILITIES

DIRECT TESTIMONY OF

AKARSH SHEILENDRANATH

FOR

SOUTHWESTERN ELECTRIC POWER COMPANY

JULY 15, 2019

TESTIMONY INDEX

SECTION PAGE

EXHIBITS

I. INTRODUCTION

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

A. My name is Akarsh Sheilendranath. I am a Senior Associate at The Brattle Group, based in the company's Boston office. My business address is One Beacon Street, Suite 2600, Boston MA 02108.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I received an MBA in Finance from New York University Stern School of Business, an M.S. in Electrical Engineering with a specialization in Power Systems Engineering from Michigan Technological University, and a B.E. in Instrumentation Technology from Siddaganga Institute of Technology in India.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND.

A. I am an energy economist with a background in power engineering and finance. I have over ten years of experience in the areas of transmission, electricity markets, system planning, and regulatory finance. I have assisted numerous clients, including regulated utilities, Independent System Operators (ISOs)/Regional Transmission Operators (RTOs), public utility commissions, and private entities, and have authored publications and reports on the subject areas related to the economic benefits of transmission investment, wind generation integration, transmission planning, public policy planning, energy and capacity market rules, and regulatory finance, including return on equity estimation for regulated electric transmission utilities. I have led multiple stakeholder engagements on behalf of senior staff of ISOs, and presented analyses of long-range strategic transmission planning, near-term market integration strategies, and cost-benefit assessments of regional public policy options. Prior to joining The Brattle Group, I was a strategic planning engineer at ISO New England

Inc. (ISO-NE) where I led ISO-NE's Strategic Planning Initiative studies for ISO-NE's Senior Staff, assessed the impacts of large-scale generation retirements, and advised on refinements to the ISO-NE's Forward Capacity Market Design and resource deliverability assessments. I was also ISO-NE's representative in the U.S. Department. of Energy's Eastern Interconnection Planning Collaborative and have presented numerous studies to stakeholders at planning advisory committee meetings, as well as to the ISO-NE Board of Directors on key strategic planning initiatives. My CV with a more detailed description of my qualification is attached as EXHIBIT AS-1.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. Southwestern Electric Power Company (SWEPCO or Company) and its sister company Public Service Company of Oklahoma (PSO) have entered into contracts to purchase three wind generation facilities (Selected Wind Facilities) that are the subject of this Application. The purpose of my testimony is to explain the calculation of the estimated future congestion and loss-related costs associated with the delivery of power to the AEP West load zone from wind farms that participated in the Company's Request for Proposals (RFP) and from the Selected Wind Facilities that were chosen through the RFP process. My analyses support:

1. The Company's calculation of the Levelized Adjusted Cost of Energy (LACOE) used to compare the participating bids in the Company's bid-evaluation process; and
2. The Company's customer benefits analysis for the Selected Wind Facilities.

My testimony describes how the congestion and loss results of market simulations based on SPP's PROMOD® models were processed for the purpose of the Company's bid evaluations, and how they were combined with the Aurora Energy Market Simulation Model

(AURORA) and PLEXOS simulations employed by the Company in its analysis of customer benefits associated with the Selected Wind Facilities.

III. OVERVIEW OF CONGESTION ANALYSIS METHODOLOGY

Q. WHAT IS THE PURPOSE OF YOUR ANALYSIS OF TRANSMISSION CONGESTION AND LOSS-RELATED COSTS?

A. The purpose of my analysis is to calculate a projection for the transmission congestion and loss-related costs of delivering power to the AEP West load zone from: 1) the wind resources bid into the RFP; and 2) the Selected Wind Facilities.

For the RFP bid evaluation, my analysis estimates the delivery costs for the wind resources—which are additional costs on top of the project bid costs received by the Company. For the Selected Wind Facilities' customer benefits analysis, I perform the same task to determine the power delivery costs associated with the Selected Wind Facilities, but with a few enhancements. To facilitate the Company's customer benefits analysis at each operating company level and under various wholesale power price sensitivities, I also combine the PROMOD results with the Company's AURORA-based markets fundamentals forecasts to generate power prices for both the Company's load zone and its conventional generation facilities. These prices are then used in the Company's PLEXOS-based cost of service calculations to determine the customer benefits of the Selected Wind Facilities. A discussion of the reasons for combining PROMOD, AURORA, and the PLEXOS results is presented in Company witness Pfeifenberger's testimony.

Q. PLEASE PROVIDE AN OVERVIEW OF THE METHODOLOGY USED TO PERFORM THE CONGESTION AND LOSS ANALYSES FOR THE BID EVALUATION ANALYSIS.

A. To analyze congestion and loss-related costs associated with the delivery of energy from a wind generation resource to the AEP West load zone, I relied on the market simulations of the SPP system prepared using SPP's stakeholder-developed 2019 Integrated Transmission Planning (2019 ITP) PROMOD models and assumptions. The market simulations were performed by the Company under my direction for two SPP-developed future years, 2024 and 2029. The reasonableness of simulation assumptions and congestion estimates is discussed in the testimony of Company witness Pfeifenberger.

Based on these PROMOD outputs, I calculated congestion and loss-related costs[1] for wind resources using congestion and loss differentials between the individual wind sites and SPP's AEP West load zone for 2024 and 2029 and combined these congestion and loss differentials with the wind generation outputs from each evaluated wind resource to determine the cost impact of congestion and losses on the output from the wind resources. I then aggregated these hourly congestion and loss-related costs on a monthly basis for both 2024 and 2029. Next, I estimated the congestion and loss-related costs for years 2025–2028 by linearly interpolating between the 2024 and 2029 congestion and loss-related costs that I previously calculated. For years 2022–2023, I estimated the congestion and loss-related

[1] For loss costs, one half of the difference in marginal loss components at the AEP West load zone and at the Selected Wind Facilities' injection pricing node is used. This is because average loss costs are half of the marginal loss costs, and approximately one half of marginal loss charges collected by SPP are refunded back to the loads.

costs by linearly extrapolating *backward* the 2024 congestion and loss costs that I calculated based on the 2024 PROMOD results.

Congestion and loss-related costs were kept constant for 2030 through 2051—which assumes that, in the longrun, as congestion costs increase, new transmission upgrades will become cost effective in the future and that SPP's planning process will identify transmission solutions to address transmission congestion and prevent congestion costs from rising further. Based on these calculations, I compiled congestion and loss costs associated with each RFP wind resource for 2022–2051. I provided these congestion and loss costs to Company witness Torpey to evaluate the Levelized Adjusted Cost of Energy (LACOE) for each of the RFP wind resources analyzed in the Company's Bid Evaluation analysis.

Q. WAS THE SAME METHODOLOGY USED TO PERFORM THE CONGESTION AND LOSS ANALYSES FOR THE SELECTED WIND FACILITIES IN THE CUSTOMER BENEFITS ANALYSIS?

A. Yes. For the customer benefits analysis for the Selected Wind Facilities, I employed the same methodology, but with a few enhancements that I explain later in my testimony.

IV. RESULTS OF CONGESTION AND LOSS ANALYSIS USED IN THE BID EVALUATION

Q. PLEASE DESCRIBE THE RESULTS OF YOUR CONGESTION AND LOSS ANALYSIS USED IN THE COMPANY'S BID EVALUATION FOR THE WIND RESOURCES THAT PARTICIPATED IN THE COMPANY'S RFP.

A. Using the PROMOD outputs for 2024 and 2029 from the "Bid Evaluation Case"[2] simulations, I evaluated congestion and loss-related costs for each of the wind resources participating in the RFP bid. As explained above, congestion and loss-related costs are evaluated as the difference in congestion components of the locational market price at the AEP West load zone (where the wind energy is delivered) and at the wind resources' injection pricing node (where the wind energy is injected into the SPP transmission grid).

Figure 1 below summarizes the congestion and loss-related costs I evaluated for each RFP wind resource for 2024 and 2029 based on the PROMOD results for the Bid Evaluation Case. As shown, congestion costs for the RFP Wind Resources range from $6.01/MWh to $19.75/MWh in 2024. For 2029, congestion costs increase to range from $6.91/MWh to $20.19/MWh. Similarly, the RFP Wind Resources' loss-related costs range from $0.34/MWh to $1.83/MWh in 2024, and from $0.52/MWh to $2.38/MWh in 2029.

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[2] See Mr. Pfeifenberger's testimony for a discussion of the simulation assumptions of the Bid Evaluation case and the other simulations cases used for the customer benefit analysis.

Figure 1: Summary of Congestion and Loss-Related Costs for RFP Wind Resources for the PROMOD Bid Evaluation Case ($/MWh)

Company Bid Ranking	Bid Number	2024 Gen-Wtd Avg Cong Costs	2024 Gen-Wtd Avg Loss Costs	2029 Gen-Wtd Avg Cong Costs	2029 Gen-Wtd Avg Loss Costs
Average		*12.95*	*1.19*	*14.07*	*1.54*
P1*	21	12.02	1.02	13.75	1.32
P2*	15	11.33	1.36	11.50	1.70
P3*	17	13.16	1.54	13.86	1.90
P4	12	15.71	1.55	17.82	2.00
P5	1	10.45	0.87	12.48	1.18
P6	6	15.64	1.14	16.10	1.44
P7	4	14.29	1.63	16.25	2.14
P8	30	13.19	1.33	15.07	1.74
P9	2	14.53	1.79	16.46	2.34
P10	31	19.28	0.94	16.16	1.16
P11	32	19.75	1.36	20.19	1.59
P12**	3	6.01	0.62	6.91	0.82
P13**	29	14.99	1.83	16.86	2.38
P14**	33	6.11	0.60	7.22	0.81
P15**	34	7.71	0.34	10.46	0.52

Source and Notes:

*RFP Wind Resources (P1, P2, and P3) are the three selected by the Company.

**RFP Wind Resources disqualified from the Company's evaluation based on the RFP's deliverability criteria.

2024 and 2029 PROMOD outputs for Bid Evaluation Case

"*Average*" is calculated as the simple average of all wind-generation-weighted average annual costs of the individual wind facilities

Congestion and loss costs for P13 represent the simple average over three different Bid 29 options.

Loss costs represent one half of the wind-generation-weighted marginal loss charges for the wind resources, since marginal loss costs mathematically amount to twice the average loss costs and the difference is refunded by SPP.

Q. HOW DID THE COMPANY APPLY THESE CONGESTION AND LOSS RESULTS IN CALCULATING THE LACOE OF THE RFP WIND RESOURCES?

A. Company witness Torpey calculated the 30-year levelized hourly congestion and loss costs for each RFP wind resource using the monthly congestion and loss costs that I provided. The Company used these congestion and loss costs, the project costs, and the cost of the gen-tie to mitigate congestion, to calculate the LACOE of each RFP wind resource. As discussed by Mr. Torpey and Mr. Pfeifenberger, the LACOE estimate was used to evaluate and rank the RFP bids.

V. CONGESTION AND LOSS ANALYSIS FOR EVALUATING CUSTOMER BENEFITS OF THE SELECTED WIND FACILITIES

Q. WHAT SIMULATION MODELS WERE USED TO PERFORM CONGESTION AND LOSS ANALYSIS FOR EVALUATING THE CUSTOMER BENEFITS OF THE SELECTED WIND FACILITIES?

A. As discussed in detail in Company witnesses Pfeifenberger and Torpey's testimonies, PROMOD, AURORA, and PLEXOS market simulation models were employed to evaluate customer benefits of the Selected Wind Facilities.

Q. WHY WERE THREE DIFFERENT SIMULATION MODELS USED FOR THE CUSTOMER BENEFITS ANALYSIS?

A. Company witness Pfeifenberger's testimony explains in greater detail the purpose and reasonableness of using multiple market models for evaluating customer savings. In summary, to evaluate the full benefits of purchasing the Selected Wind Facilities under a range of different conditions, the Company needed to employ three simulation tools. Each of these three tools, PROMOD, AURORA, and PLEXOS, was used to perform forward-looking market simulations, with each tool deployed to take advantage of its specific modeling capabilities for facilitating a comprehensive evaluation of the benefits of the Selected Wind Facilities. Specifically, PROMOD provides market prices that reflect congestion and loss pricing where the Company's load and thermal generation units are located. However, unlike PLEXOS, PROMOD is neither set up to simulate SWEPCO and PSO individually nor to forecast long-term prices under various wholesale power price sensitivities through 2051, like AURORA. Therefore, PROMOD cannot be used to assess changes in SWEPCO's and PSO's production costs, market purchase costs, off-system sales revenues, and other costs at the operating-company level in the longterm. On the other hand, the Company's AURORA and PLEXOS models are not set up to simulate transmission congestion and losses, so they are unable to assess the extent to which locational wholesale power prices, congestion costs, and loss-related costs affect the delivered costs and benefits of the Selected Wind Facilities.

Q. PLEASE EXPLAIN THE METHODOLOGY EMPLOYED TO ESTIMATE CONGESTION AND LOSS-RELATED COSTS FOR THE SELECTED WIND FACILITIES FOR THE CUSTOMER BENEFITS ANALYSIS.

A. With the exception of a few enhancements, the methodology I employed to estimate congestion and loss-related costs of the Selected Wind Facilities is consistent with the methodology I employed to estimate congestion and loss-related costs of all the RFP wind resources in the bid evaluation phase. Specifically, to support the Company's customer benefits analysis, I calculated the congestion and loss-related costs for each of the Selected Wind Facilities by calculating the difference in congestion and loss components of locational market prices at the AEP West load zone and at the Selected Wind Facilities' injection pricing nodes, based on the 2024 and 2029 PROMOD results. But, unlike in the Bid Evaluation analysis—where I performed this calculation only for one PROMOD case—in the customer benefits analysis, I performed this calculation for two PROMOD cases, the "Base Case" and "No-SPP-Upgrades Case." Details regarding the PROMOD cases employed for the Bid Evaluation analysis and the customer benefits analysis are discussed in Mr. Pfeifenberger's testimony.

Q. WERE ADJUSTMENTS NEEDED TO COMBINE THE PROMOD-BASED CONGESTION AND LOSS COSTS WITH AURORA-BASED FUNDAMENTALS FORECASTS FOR MARKET PRICES?

A. Yes. As discussed previously, the AURORA model is not set up to simulate transmission congestion and losses. Therefore, I scaled the PROMOD-based congestion and loss-related costs that I calculated for the Selected Wind Facilities, based on the long-term fundamentals forecast prices from the Company's AURORA model.[3] I performed this scaling to be consistent with the extent to which AURORA fundamentals forecast prices for SPP Central are higher or lower than the prices for SPP Central in the PROMOD simulations. The scaled congestion and loss-related costs were then employed in the PLEXOS model to facilitate the Company's customer benefits analysis, which is performed at the operating company level employing the Company's long-term fundamentals forecast market prices for 2021–2051.

After calculating the congestion and loss-related costs of the Selected Wind Facilities for 2024 and 2029, and then scaling to AURORA fundamentals forecast prices, I estimated congestion and loss-related costs of the Selected Wind Facilities for years 2021–2023, 2025–2028, and 2030–2051. For 2021–2023, I estimated congestion and loss-related costs by applying the implied year-over-year growth rates in the Company's fundamental price forecasts. For 2025–2028, I interpolated congestion and loss-related costs by "straight-lining" between the AURORA-scaled 2024 and 2029 congestion and loss values. For 2030–2051, I assumed that congestion and loss-related costs would remain constant at the AURORA-scaled 2029 values.

[3] For scaling congestion and loss costs, I applied the ratio of the annual average power price projected by the Company's long-term fundamentals forecast at SPP Central zone, to the PROMOD simulated annual average power price at SPP Central comparable zones in PROMOD. I performed this PROMOD to AURORA congestion and loss costs scaling for both 2024 and 2029 PROMOD simulation years.

Q. HOW WERE PROMOD RESULTS COMBINED WITH AURORA PRICES TO DEVELOP MARKET PRICE INPUTS FOR THE COMPANY'S PLEXOS-BASED CUSTOMER BENEFITS ANALYSIS?

A. To facilitate the Company's customer benefits analysis, I performed several data processing tasks, combining PROMOD and AURORA results to develop inputs for the Company's PLEXOS simulations.

First, I processed PROMOD's prices from the 2024 and 2029 results to evaluate SPP locational market prices for SWEPCO's and PSO's thermal units and for the AEP West load zone. Next, I calculated market prices for several PROMOD defined SPP generation zones that collectively reflect the "SPP Central" zone as defined in the Company's AURORA model.[4] I then calculated the PROMOD price differentials from the PROMOD SPP Central zone to the SWEPCO generation zone, the PSO generation zone, and the AEP West load zone. Applying these price differentials on a percentage basis to the AURORA fundamentals forecast market prices, I developed the AURORA prices for SWEPCO and PSO generation zones, and for the AEP West load zone, for years 2024 and 2029. I refer to these as the "adjusted AURORA prices." These adjusted AURORA prices are part of the inputs used by the Company for its PLEXOS cost of service simulations. I estimated these adjusted AURORA prices for years 2021-2051 by linear interpolation (for 2025-28), backward extrapolation (for 2021-23), and by maintaining the 2029 percentage adjustments for the out years. EXHIBIT AS-2 contains additional details about how I performed these calculations.

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[4] AURORA's SPP Central zone maps closely to the generation resources of SPP's AEP zone, GRDA zone, OKGE zone, SPS zone, and WFEC zone. To reflect AURORA's SPP Central zone in PROMOD, I calculated the hourly generation-weighted-average LMP for these five generation zones.

Q. PLEASE LIST THE PROMOD CASES AND THE AURORA SENSITIVITIES FOR WHICH YOU CALCULATED THESE MARKET PRICES TO SUPPORT THE COMPANY'S CUSTOMER BENEFIT ANALYSIS.

A. As explained above, I developed adjusted AURORA market prices by combining PROMOD results with AURORA fundamentals forecasts. Specifically, I relied on results from two PROMOD cases—the "Base Case" and the "No-SPP-Upgrades Case." As described in detail in witness Pfeifenberger's testimony, the "Base Case" eliminates constraints associated with the transmission needs that SPP has already identified in the currently-ongoing ITP process. In contrast, the "No-SPP-Upgrades Case" retains all these transmission constraints, with the exception of one constraint.[5]

I used the results from each of these two PROMOD cases and combined them with five AURORA fundamentals forecast cases to develop ten sets of adjusted AURORA market prices. Each set reflected combining one of these two PROMOD cases with the following five AURORA fundamentals forecast cases used in the customer benefits analysis:

1) Base Gas Price/With Carbon
2) Base Gas Price/No Carbon,
3) Low Gas Price/With Carbon,
4) High Gas Price/With Carbon, and
5) Low Gas Price/No Carbon.

As a result, I developed AURORA market prices for each of these five fundamentals forecasts for both the Base Case and No-SPP-Upgrades-Case PROMOD cases. In addition

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[5] The Company assumed that one SPP identified ITP 2019 need, namely, Cleveland 138 kV bus-tie, located west of Tulsa, will be addressed by an SPP solution in the near term since it was identified by SPP as both an economic- and operational need in the 2019 ITP Study, and because the transmission upgrade costs were expected to be low.

to the ten sets of adjusted AURORA market prices, I also developed scaled congestion and loss results for each combination of PROMOD and AURORA cases.

Q. PLEASE SUMMARIZE THE MARKET PRICE RESULTS USED IN THE COMPANY'S PLEXOS SIMULATIONS TO DETERMINE CUSTOMER BENEFITS OF THE SELECTED WIND FACILITIES.

A. I calculated market prices for SWEPCO generation and PSO generation zones, and AEP West load zone for each of the AURORA fundamentals forecast cases that Company witness Torpey analyzes in the customer benefits analysis. Figure 2 below shows the results for years 2024 and 2029 for the five adjusted AURORA cases based on the PROMOD "Base Case," and Figure 3 shows the results for the same years for the five adjusted AURORA cases based on the PROMOD "No-SPP-Upgrades Case."

Figure 2
Summary of adjusted-AURORA Market Prices in 2024 and 2029
(Based on PROMOD "Base Case")

Annual Average ($/MWh)	2024				
	Base Gas	Base Gas No Carbon	Low Gas	High Gas	Low Gas No Carbon
AEP West Load Zone LMP	$30.26	$30.07	$25.84	$34.02	$26.08
PSO Gen LMP	$29.79	$29.61	$25.44	$33.50	$25.68
SWEPCo Gen LMP	$29.92	$29.74	$25.54	$33.64	$25.78
Annual Average ($/MWh)	**2029**				
	Base Gas	**Base Gas No Carbon**	**Low Gas**	**High Gas**	**Low Gas No Carbon**
AEP West Load Zone LMP	$46.23	$36.31	$40.05	$51.39	$30.79
PSO Gen LMP	$45.52	$35.78	$39.44	$50.59	$30.36
SWEPCo Gen LMP	$45.78	$35.88	$39.63	$50.88	$30.42

Figure 3
Summary of adjusted-AURORA Market Prices in 2024 and 2029
(Based on PROMOD "No-SPP-Upgrades Case")

Annual Average ($/MWh)	2024				
	Base Gas	Base Gas No Carbon	Low Gas	High Gas	Low Gas No Carbon
AEP West Load Zone LMP	$31.08	$30.89	$26.54	$34.94	$26.78
PSO Gen LMP	$30.41	$30.23	$25.98	$34.19	$26.22
SWEPCo Gen LMP	$30.84	$30.66	$26.32	$34.67	$26.57
Annual Average ($/MWh)	**2029**				
	Base Gas	Base Gas No Carbon	Low Gas	High Gas	Low Gas No Carbon
AEP West Load Zone LMP	$47.85	$37.57	$41.45	$53.19	$31.86
PSO Gen LMP	$46.69	$36.73	$40.46	$51.89	$31.16
SWEPCo Gen LMP	$46.75	$36.60	$40.46	$51.96	$31.03

Q. PLEASE SUMMARIZE THE CONGESTION AND LOSS-RELATED RESULTS USED IN THE COMPANY'S PLEXOS SIMULATIONS TO DETERMINE CUSTOMER BENEFITS OF THE SELECTED WIND FACILITIES.

A. Figure 4 through Figure 13 below summarize the congestion and loss-related costs I evaluated for the Selected Wind Facilities for 2021-2051, for each of the ten adjusted AURORA cases.

Summary of Congestion and Loss Results for AURORA cases, based on PROMOD "Base Case":

Figure 4
Summary of Congestion and Loss-related Costs for Selected Wind Facilities – (PROMOD "Base Case" with AURORA Base Gas Price/With Carbon)

Year	Congestion Costs ($ million)	Losses Costs ($ million)	Output (GWh)	$/MWh
2021	$5.50	$1.09	813	$8.11
2022	$37.30	$5.76	5,754	$7.48
2023	$38.66	$5.97	5,754	$7.76
2024	$40.31	$6.24	5,770	$8.07
2025	$45.17	$7.01	5,754	$9.07
2026	$50.03	$7.78	5,754	$10.05
2027	$54.89	$8.55	5,754	$11.02
2028	$59.75	$9.31	5,770	$11.97
2029 - 2050	$64.61	$10.08	5,754	$12.98
2051	$55.19	$8.15	4,941	$12.82

Note: Congestion and Loss Costs for 2021 reflect costs associated with only one of the three Selected Wind Facilities as only that facility is scheduled to become operational in 2021 Congestion and loss costs for 2051 reflect these costs for only the other two Selected Wind Facilities.

Figure 5
Summary of Congestion and Loss-related Costs for Selected Wind Facilities (PROMOD "Base Case" with AURORA Base Gas Price/No Carbon)

Year	Congestion Costs ($ million)	Losses Costs ($ million)	Output (GWh)	$/MWh
2021	$5.51	$1.10	813	$8.12
2022	$37.22	$5.75	5,754	$7.47
2023	$38.64	$5.97	5,754	$7.75
2024	$40.06	$6.20	5,770	$8.02
2025	$42.23	$6.55	5,754	$8.48
2026	$44.40	$6.90	5,754	$8.92
2027	$46.57	$7.25	5,754	$9.35
2028	$48.74	$7.60	5,770	$9.76
2029 - 2050	$50.90	$7.94	5,754	$10.23
2051	$43.48	$6.43	4,941	$10.10

Note: Congestion and Loss Costs for 2021 reflect costs associated with only one of the three Selected Wind Facilities as only that facility is scheduled to become operational in 2021. Congestion and loss costs for 2051 reflect these costs for only the other two Selected Wind Facilities.

Figure 6
Summary of Congestion and Loss-related Costs for the Selected Wind Facilities (PROMOD "Base Case" with AURORA Low Gas Price/With Carbon)

Year	Congestion Costs ($ million)	Losses Costs ($ million)	Output (GWh)	$/MWh
2021	$4.88	$0.97	813	$7.19
2022	$32.55	$5.03	5,754	$6.53
2023	$33.53	$5.18	5,754	$6.73
2024	$34.46	$5.34	5,770	$6.90
2025	$38.77	$6.02	5,754	$7.78
2026	$43.08	$6.70	5,754	$8.65
2027	$47.40	$7.38	5,754	$9.52
2028	$51.71	$8.06	5,770	$10.36
2029 - 2050	$56.02	$8.74	5,754	$11.26
2051	$47.85	$7.07	4,941	$11.12

Note. Congestion and Loss Costs for 2021 reflect costs associated with only one of the three Selected Wind Facilities as only that facility is scheduled to become operational in 2021. Congestion and loss costs for 2051 reflect these costs for only the other two Selected Wind Facilities.

Figure 7
Summary of Congestion and Loss-related Costs for Selected Wind Facilities (PROMOD "Base Case" with High Gas Price/With Carbon)

Year	Congestion Costs ($ million)	Losses Costs ($ million)	Output (GWh)	$/MWh
2021	$6.06	$1.20	813	$8.93
2022	$41.55	$6.42	5,754	$8.34
2023	$43.31	$6.69	5,754	$8.69
2024	$45.33	$7.02	5,770	$9.07
2025	$50.62	$7.86	5,754	$10.16
2026	$55.92	$8.69	5,754	$11.23
2027	$61.21	$9.53	5,754	$12.29
2028	$66.50	$10.37	5,770	$13.32
2029 - 2050	$71.80	$11.21	5,754	$14.43
2051	$61.33	$9.06	4,941	$14.25

Note: Congestion and Loss Costs for 2021 reflect costs associated with only one of the three Selected Wind Facilities as only that facility is scheduled to become operational in 2021. Congestion and loss costs for 2051 reflect these costs for only the other two Selected Wind Facilities.

Figure 8
Summary of Congestion and Loss-related Costs for Selected Wind Facilities
(PROMOD "Base Case" with Low Gas Price/No Carbon)

Year	Congestion Costs ($ million)	Losses Costs ($ million)	Output (GWh)	$/MWh
2021	$4.88	$0.97	813	$7.19
2022	$32.57	$5.03	5,754	$6.54
2023	$33.69	$5.21	5,754	$6.76
2024	$34.78	$5.38	5,770	$6.96
2025	$36.47	$5.66	5,754	$7.32
2026	$38.15	$5.93	5,754	$7.66
2027	$39.84	$6.20	5,754	$8.00
2028	$41.53	$6.47	5,770	$8.32
2029 - 2050	$43.22	$6.75	5,754	$8.68
2051	$36.92	$5.46	4,941	$8.58

Note: Congestion and Loss Costs for 2021 reflect costs associated with only one of the three Selected Wind Facilities as only that facility is scheduled to become operational in 2021. Congestion and loss costs for 2051 reflect these costs for only the other two Selected Wind Facilities.

Summary of Congestion and Loss Results for AURORA cases, based on PROMOD "No-SPP-Upgrades Case":

Figure 9
Summary of Congestion and Loss-related Costs for Selected Wind Facilities
(PROMOD "No-SPP-Upgrades Case" with AURORA Base Gas Price/With Carbon)

Year	Congestion Costs ($ million)	Losses Costs ($ million)	Output (GWh)	$/MWh
2021	$6.20	$1.08	813	$8.95
2022	$55.34	$5.71	5,754	$10.61
2023	$57.36	$5.93	5,754	$11.00
2024	$59.86	$6.19	5,770	$11.45
2025	$66.49	$6.95	5,754	$12.76
2026	$73.11	$7.70	5,754	$14.04
2027	$79.73	$8.45	5,754	$15.33
2028	$86.36	$9.20	5,770	$16.56
2029 - 2050	$92.98	$9.95	5,754	$17.89
2051	$82.18	$8.05	4,941	$18.26

Note: Congestion and Loss Costs for 2021 reflect costs associated with only one of the three Selected Wind Facilities as only that facility is scheduled to become operational in 2021. Congestion and loss costs for 2051 reflect these costs for only the other two Selected Wind Facilities.

Figure 10
Summary of Congestion and Loss-related Costs for Selected Wind Facilities (PROMOD "No-SPP-Upgrades Case" with AURORA Base Gas Price/No Carbon)

Year	Congestion Costs ($ million)	Losses Costs ($ million)	Output (GWh)	$/MWh
2021	$6.20	$1.08	813	$8.95
2022	$55.25	$5.71	5,754	$10.59
2023	$57.35	$5.92	5,754	$11.00
2024	$59.50	$6.16	5,770	$11.38
2025	$62.25	$6.49	5,754	$11.95
2026	$65.00	$6.83	5,754	$12.48
2027	$67.76	$7.17	5,754	$13.02
2028	$70.51	$7.51	5,770	$13.52
2029 - 2050	$73.26	$7.84	5,754	$14.10
2051	$64.75	$6.35	4,941	$14.39

Note: Congestion and Loss Costs for 2021 reflect costs associated with only one of the three Selected Wind Facilities as only that facility is scheduled to become operational in 2021. Congestion and loss costs for 2051 reflect these costs for only the other two Selected Wind Facilities.

Figure 11
Summary of Congestion and Loss-related Costs for Selected Wind Facilities (PROMOD "No-SPP-Upgrades Case" with AURORA Low Gas Price/With Carbon)

Year	Congestion Costs ($ million)	Losses Costs ($ million)	Output (GWh)	$/MWh
2021	$5.49	$0.96	813	$7.93
2022	$48.30	$4.99	5,754	$9.26
2023	$49.76	$5.14	5,754	$9.54
2024	$51.17	$5.30	5,770	$9.79
2025	$57.07	$5.96	5,754	$10.95
2026	$62.96	$6.63	5,754	$12.09
2027	$68.85	$7.30	5,754	$13.23
2028	$74.74	$7.96	5,770	$14.33
2029 - 2050	$80.63	$8.63	5,754	$15.51
2051	$71.26	$6.98	4,941	$15.84

Note. Congestion and Loss Costs for 2021 reflect costs associated with only one of the three Selected Wind Facilities as only that facility is scheduled to become operational in 2021. Congestion and loss costs for 2051 reflect these costs for only the other two Selected Wind Facilities.

Figure 12
Summary of Congestion and Loss-related Costs for Selected Wind Facilities
(PROMOD "No-SPP-Upgrades Case" with AURORA High Gas Price/With Carbon)

Year	Congestion Costs ($ million)	Losses Costs ($ million)	Output (GWh)	$/MWh
2021	$6.82	$1.19	813	$9.85
2022	$61.68	$6.37	5,754	$11.83
2023	$64.29	$6.64	5,754	$12.33
2024	$67.31	$6.97	5,770	$12.87
2025	$74.52	$7.78	5,754	$14.30
2026	$81.72	$8.60	5,754	$15.70
2027	$88.93	$9.42	5,754	$17.09
2028	$96.13	$10.24	5,770	$18.44
2029 - 2050	$103.33	$11.06	5,754	$19.88
2051	$91.32	$8.95	4,941	$20.30

Note: Congestion and Loss Costs for 2021 reflect costs associated with only one of the three Selected Wind Facilities as only that facility is scheduled to become operational in 2021 Congestion and loss costs for 2051 reflect these costs for only the other two Selected Wind Facilities.

Figure 13
Summary of Congestion and Loss-related Costs for Selected Wind Facilities
(PROMOD "No-SPP-Upgrades Case" with AURORA Low Gas Price/No Carbon)

Year	Congestion Costs ($ million)	Losses Costs ($ million)	Output (GWh)	$/MWh
2021	$5.49	$0.96	813	$7.93
2022	$48.34	$4.99	5,754	$9.27
2023	$50.00	$5.17	5,754	$9.59
2024	$51.65	$5.34	5,770	$9.88
2025	$53.76	$5.61	5,754	$10.32
2026	$55.87	$5.87	5,754	$10.73
2027	$57.98	$6.13	5,754	$11.14
2028	$60.09	$6.40	5,770	$11.52
2029 - 2050	$62.20	$6.66	5,754	$11.97
2051	$54.97	$5.39	4,941	$12.22

Note: Congestion and Loss Costs for 2021 reflect costs associated with only one of the three Selected Wind Facilities as only that facility is scheduled to become operational in 2021. Congestion and loss costs for 2051 reflect these costs for only the other two Selected Wind Facilities

Q. HOW WERE THESE MARKET PRICES AND CONGESTION AND LOSS-RELATED COSTS USED BY THE COMPANY?

A. Company witness Torpey used these adjusted AURORA market prices and the scaled congestion and loss-related costs for the Selected Wind Facilities in the Company's PLEXOS-based customer benefits analyses.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

QUALIFICATIONS OF AKARSH SHEILENDRANATH

Akarsh Sheilendranath is a Senior Associate at *The Brattle Group* where he is a member of the firm's Utility Regulation and Electric Power practices. He received an M.B.A. in Finance from New York University's Stern School of Business and holds a M.S. in Electrical Engineering, with a specialization in Power Systems Engineering from Michigan Technological University. Prior to joining *The Brattle Group*, Mr. Sheilendranath was a Senior Strategic Planning Engineer at Eversource Energy, based in Hartford Connecticut, and a prior to that, a Strategic Planning Engineer at ISO New England Inc. ("ISO-NE") where he led ISO-NE's Strategic Planning Initiative studies for ISO-NE's Senior Staff and the Board of Directors.

REPRESENTATIVE EXPERIENCE

Electric Transmission Pricing, Cost Benefit Analysis, and Benefits of Competition

- Mr. Sheilendranath co-authored an extensive review of competitive transmission procurement practices of North American system operators and quantified the benefits of competitive transmission procurement.
- Mr. Sheilendranath developed a market simulation and benefit-cost framework to quantify the benefits of AEP's proposed Wind Catcher project, delivered via a 765 kV dedicated generation tie-line from Oklahoma Panhandle to AEP's load centers in the Tulsa area.
- Mr. Sheilendranath provided strategic advisory for AEP's leadership team in the Wind Catcher Project development, and assisted the company on a wide-range of issues—from ideation to regulatory approval processes, including analysis of renewable PPAs, developing market simulations, and designing benefit-cost frameworks to analyze the economics of integrating Wind Catcher's 2,000 MW of wind generating resources, delivered through a 765 kV generation tie line from the wind-rich Oklahoma Panhandle region to the company's load centers in Oklahoma, Arkansas, Louisiana and Texas.
- Mr. Sheilendranath conducted Benefit-Cost Analysis of New York Transmission Upgrades for New York Public Service Commission, wherein he assisted NY DPS Staff and NYISO in analyzing economic benefits of each of the proposed transmission portfolios. Mr. Sheilendranath worked extensively with NY DPS Staff in developing detailed cost estimates and estimating revenue requirements for each proposed portfolio, and led the design and quantification analyses to analyze the full-range of benefits of avoided transmission and reduced future transmission refurbishment assessments for each transmission portfolio analyzed. In the matter of: Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades," Appendix 1 to Comparative Evaluation of Alternating Current Transmission Upgrade Alternatives, Trial Staff Final Report, *Proceeding on Motion of the Commission to Examine Alternating Current Transmission Upgrades*, New York State Department of Public Service, Matter No. 12-02457, Case No. 12-T-0502, September 22, 2015.
- Mr. Sheilendranath led multiple stakeholder engagements on behalf of senior staff of ISO New England, and in another separate engagement, on behalf of the staff of Southwest Power Pool (SPP). He presented analyses of long-range strategic planning for renewable futures, near-term market integration strategies, and cost-benefit assessments of regional reliability and public policy options for these ISO/RTOs.

- Mr. Sheilendranath worked with the Southwest Power Pool (SPP) and its Committees in their efforts to develop planning approaches, assessing benefits and cost allocations of SPP's $7 billion portfolio of transmission projects, analyzing benefit metrics and evaluation frameworks for interregional transmission projects. Presented study results and recommendations to various SPP Stakeholders on behalf of the SPP Staff.

Transmission Planning, Public Policy, Strategic Planning

- Mr. Sheilendranath provided sworn Affidavit before the Federal Energy Regulatory Commission, Docket No. EL19-34-000, on behalf of Brookfield Energy Marketing LP's complaint against PJM Interconnection, L.L.C. ("PJM") with respect to PJM's application of its most recent changes to its Tariff and Reliability Assurance Agreement regarding Pseudo-ties and their eligibility for participating in PJM's Capacity Market, January 18, 2019.
- Mr. Sheilendranath provided strategic support in developing numerous renewable energy transmission investment options, valued between $0.5B-$2B, for the Board of Directors of a large utility in New England; he assisted in developing options to strategically align company's near-term growth opportunities with the long-term renewable vision of New England states, and co-presented investment options and recommendations to the company's Board of Directors.
- Mr. Sheilendranath represented ISO New England in the Department of Energy (DOE)-funded national planning coordination process, and has presented ISO's strategic planning initiatives to ISO Board of Directors and at advisory committees.
- Mr. Sheilendranath analyzed for client merits- and demerits of alternative transmission solutions to integrating large-scale off-shore wind developments in the eastern US corridor for independent developers, and recently was the panelist and moderator for offshore wind transmission conference panels on financing, and on economics and viability of offshore grids.
- Mr. Sheilendranath advised a large international utility on its market entry strategies to access U.S. transmission markets, and regarding acquisition of transmission assets in the U.S.

Cost of Capital and Utility Regulatory Finance

- *Ongoing Cases:* Mr. Sheilendranath is currently assisting two electric transmission utility clients in two separate cases, in estimating the Return on Equity using FERC's proposed new methodology from the October 2018 order in the matter of Coakley remand. *Mr. Sheilendranath will be co-sponsoring his Testimony at the Federal Energy Regulatory Commission as the ROE expert.*
- Mr. Sheilendranath estimated ROE using FERC methodology and developed direct testimony for a Brattle expert for submission at the Federal Energy Regulatory Commission, Docket No. ER17-706-000 on behalf of Gridliance West Transco LLC, regarding Gridliance West's application pursuant to section 205 of the Federal Power Act regarding the appropriate ROE, cost of debt, and capital structure to allow Gridliance West Transco LLC to earn on the transmission facilities acquired from Valley Electric Association, December 2016. Assisted in Gridlinace West's settlement conference calls with the commission staff and the parties, and more recently, analyzed the transmission incentives, assisting in filing and settlement discussion on incentive transco adder.
- Mr. Sheilendranath estimated ROE using FERC methodology and prepared a direct testimony and supporting exhibits for Brattle expert for submission before the Federal Energy Regulatory Commission, Docket No. EC17-049-000, on behalf of Gridliance West Transco LLC, regarding

GridLiance West's application pursuant to section 203 of the Federal Power Act (FPA) to acquire certain high voltage transmission facilities from Valley Electric Transmission Association, LLC (VETA) through its parent non-profit electric cooperative parent Valley Electric Association, Inc. (Valley Electric), December 2016.

- Mr. Sheilendranath estimated ROE using FERC methodology and developed direct testimony and supporting exhibits for a Brattle expert for submission before the Federal Energy Regulatory Commission, Docket No. ER16-2632-000, on behalf of Trans Bay Cable LLC, regarding the appropriate ROE and capital structure to allow for its regulated electric transmission assets, September 2016. He also provided long-term, continual strategic advisory support to Trans Bay Cable's executives during the significant uncertainty surrounding the rate case as a result of Opinion 531 remand. Further, he assisted the client and its legal counsel on interrogatories, drafting of briefs.
- Mr. Sheilendranath led the estimation of Natural Gas pipeline ROE using FERC's methodology and developed direct testimony for a Brattle expert for submission before the Federal Energy Regulatory Commission, Docket No. RP17-598-000 on behalf of Great Lakes Gas Transmission Limited Partnership, regarding the appropriate ROE to allow for its regulated natural gas pipeline assets, March 2017.
- Mr. Sheilendranath led the ROE estimation analysis employing DCF, CAPM and Risk Premium financial models, and assisted in the preparation of direct and rebuttal testimony for Brattle expert for submission before the Michigan Public Service Commission on behalf of the DTE Gas Company, Case No. U-18999, on the cost of common equity capital for DTE Gas Company's regulated natural gas distribution assets, February 2018.
- Mr. Sheilendranath led the ROE estimation analysis employing DCF and CAPM financial models, and assisted in the preparation of direct and rebuttal testimony for Brattle expert for submission before the Michigan Public Service Commission on behalf of the DTE Gas Company (Case No. U-17799) on the cost of capital for DTE Gas Company's natural gas distribution assets, December 2015 and May 2016.
- Mr. Sheilendranath assisted in the ROE estimation analysis employing FERC's DCF methodology and led the Economic Conditions Impact Assessment in the preparation of direct testimony and supporting exhibits for Brattle expert for submission before the Federal Energy Regulatory Commission, Docket No. RP16-440-000, on behalf of ANR Pipeline Company, regarding the appropriate ROE to allow for its regulated natural gas pipeline assets, January 2016.
- For the Ontario Energy Board (OEB) Staff, as project manager, Mr. Sheilendranath analyzed the appropriate capital structure for a power generator that is engaged in a nuclear refurbishment program, and assisted Brattle expert submit evidentiary report advising the OEB Staff.

TESTIMONY, ARTICLES, REPORTS, AND PUBLICATIONS

- Provided sworn Direct Affidavit before the Federal Energy Regulatory Commission, Docket No. EL19-34-000, Affidavit of Johannes P. Pfeifenberger and Akarsh Sheilendranath on behalf of Brookfield *Energy Marketing LP's complaint against PJM Interconnection, L.L.C. ("PJM") with respect to PJM's application of its most recent changes to its Tariff and Reliability Assurance Agreement,* January 18, 2019.
- Provided sworn Reply Affidavit before the Federal Energy Regulatory Commission, Docket No. EL19-34-000, Reply Affidavit of Johannes P. Pfeifenberger and Akarsh Sheilendranath on behalf of

Brookfield *Energy Marketing LP's complaint against PJM Interconnection, L.L.C. ("PJM") with respect to PJM's application of its most recent changes to its Tariff and Reliability Assurance Agreement,* February 25, 2019.

- Integrating Renewables into Lower Michigan's Electric Grid: Resource Adeqaucy, Operational Analysis, and Implications, prepared for DTE Energy (with J. Chang, K. Van Horn, and J. Pfeifenberger), March 29, 2018.
- Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value, prepared for LSP Transmission Holdings (with J. Pfeifenberger and J. Chang), April 2019.
- Transmission Solutions: Potential Cost Savings Offered by Competitive Planning Processes, prepared for LSP Transmission Holdings, GridLiance, presented at the 2018 National Association of Regulatory Utility Commissioners (NARUC) Annual Meeting (with J. Chang, and J. Pfeifenberger), November 13, 2018.
- Transmission Competition Under FERC Order No. 1000: What we Know About Cost Savings to Date, presented to WIRES (with J. Pfeifenberger, J. Chang), October 25, 2018
- *Resetting FERC ROE Policy: A Window of Opportunity, Whitepaper & Presentation Published by The Brattle Group, Inc.,* (with R. Mudge and F. Graves), May 2018.
- *Transmission Competition Under FERC Order No. 1000 at a Crossroads: Reinforce or Repeal?,* prepared for LSP Transmission Holdings, GridLiance, presented to American Public Power Association, 2018 L&R Conference, Charleston, SC (with J. Pfeifenberger and J. Chang), October 10, 2018.
- *U.S. Offshore Wind Generation and Transmission Needs,* Presented at the Offshore Wind Transmission USA Conference in New York (with J. Chang and J. Pfeifenberger), September 17-18, 2018.
- *In the matter of: Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades," Appendix 1 to Comparative Evaluation of Alternating Current Transmission Upgrade Alternatives,* Trial Staff Final Report, Proceeding on Motion of the Commission to Examine Alternating Current Transmission Upgrades, New York State Department of Public Service, Matter No. 12-02457, Case No. 12-T-0502, September 22, 2015. Presented to NYISO and DPS Staff.
- *Lake Erie Market Assessment Report,* prepared for ITC Lake Erie Connector LLC, May 2015 (with J. Chang, J. Pfeifenberger).
- *Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid,* prepared for WIRES (with J. Chang and J. Pfeifenberger), April 2015.

DETAILED DESCRIPTION OF THE CALCULATION OF ADJUSTED-AURORA PRICES

Details of Adjusted-AURORA Market Prices Calculation

As noted in Testimony, the Company employed three tools—PROMOD, AURORA, and PLEXOS to evaluate the customer benefits of purchasing the Selected Wind Facilities. Below, I describe the detailed steps that I undertook to process and combine PROMOD and AURORA results to prepare inputs for the Company's PLEXOS simulations.

➢ *Step 1:* Estimating Locational Market Prices and Congestion in PROMOD

First, I processed PROMOD's hourly locational prices from the 2024 and 2029 results to evaluate: (1) hourly generation-weighted average market prices for PSO's and SWEPCO's thermal units, (2) hourly market prices for the PROMOD defined AEP West load zone, and (3) hourly generation-weighted average market prices for a select set[1] of PROMOD defined SPP generation zones that collectively reflect the "SPP Central" zone of the company's AURORA model. The PSO and SWEPCO generation zone prices, the AEP West load zone prices, and the SPP Central zones prices from PROMOD are then used for adjusting the AURORA wholesale prices for SPP Central to develop hourly adjusted-AURORA PSO and SWEPCO generation zone prices, and the adjusted-AURORA AEP West load zone prices. These are the price inputs then used by the Company for its PLEXOS cost of service simulations.

➢ *Step 2:* Adjusting AURORA Prices based on PROMOD Prices

After processing PROMOD hourly results to develop hourly PSO and SWEPCO generation prices, the SPP Central PROMOD zone prices, and the AEP West load zone prices, I calculated the annual average PROMOD price differential percentages for each hour of the day between: (1) AEP West load zone and SPP Central zone prices; (2) PSO generation zone prices and SPP

[1] AURORA's SPP Central zone maps closely to the generation resources of SPP's AEP zone, GRDA zone, OKGE zone, SPS zone, and WFEC zone. To reflect AURORA's SPP Central zone in PROMOD, I calculated the hourly generation-weighted average LMP for these five generation zones.

Central zone prices, and (3) SWEPCO generation zone prices and SPP Central zone prices. With this calculation, I produced hourly price differential percentages for each of the PSO generation zone, SWEPCO generation zone, and AEP West load zone, and for each of two PROMOD simulation years of 2024 and 2029. I then applied these average hourly SPP Central price differential percentages to the hourly prices produced by AURORA for the Company's fundamentals forecast. I performed this analysis for 2024 and 2029, applying the 2024 and 2029 PROMOD-based price differential percentages to produce the 2024 and 2029 hourly adjusted-AURORA prices for the PSO generation zone, SWEPCO generation zone, and AEP West load zone. The result are adjusted AURORA prices for PSO generation, SWEPCO generation, and AEP Load that reflect the appropriate congestion and loss-related price differences scaled to the price level of each AURORA case.

➢ *Step 3:* Estimating Adjusted AURORA Prices for 2021-23, 2025-28, & 2030-52

For estimating the adjusted-AURORA hourly prices for other years of the study, I performed the following:

For 2021-2023 & 2025-2028:

- For 2025-2028, I interpolated PSO generation, SWEPCO generation and AEP Load zone prices by "straight-lining" between 2024 and 2029 hourly price differential percentages, and then applying those price differential percentages to produce hourly adjusted-AURORA prices for the years 2025-28. For 2021-2023, I extrapolated backward from the 2024 hourly price differential percentages to produce the hourly adjusted-AURORA prices for 2021-2023.

For 2030-2052:

- I applied the 2029 hourly price differential percentages to AURORA fundamentals forecast prices every year thereafter to produce for each year, the hourly adjusted-AURORA prices for PSO generation, SWEPCO generation, and the AEP West load zone.

➢ *Step 4:* Estimating 30-yr AURORA-scaled Congestion & Loss Costs for the Selected Wind Facilities

I estimated the 30-yr AURORA-scaled congestion and loss costs for the Selected Wind Facilities as explained in the testimony's Q&A describing the methodology for estimating wind-related congestion and loss costs.

***

PUC DOCKET NO. _________

PUBLIC UTILITY COMMISSION OF TEXAS

APPLICATION OF

SOUTHWESTERN ELECTRIC POWER COMPANY

FOR CERTIFICATE OF CONVENIENCE AND NECESSITY

AUTHORIZATION AND RELATED RELIEF FOR

THE ACQUISITION OF WIND GENERATION FACILITIES

DIRECT TESTIMONY OF

KAMRAN ALI

FOR

SOUTHWESTERN ELECTRIC POWER COMPANY

JULY 15, 2019

TESTIMONY INDEX

I. INTRODUCTION

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

A. My name is Kamran Ali. American Electric Power Service Corporation (AEPSC), one of several subsidiaries of American Electric Power Company, Inc. (AEP), employs me. I am currently Managing Director of Transmission Planning for AEPSC. My business address is 8500 Smiths Mill Road, New Albany, OH 43054.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I received a Bachelor of Science – Electrical Engineering degree from the University of Alabama in Tuscaloosa, Alabama and a Master of Science, Electrical Engineering degree from Kansas State University in Manhattan, Kansas. I also received a Master of Business Administration degree from Ohio University in Athens, Ohio.

Q. WHAT IS YOUR PROFESSIONAL BACKGROUND?

A. I started my career at SMC Electrical before joining AEPSC as an electrical engineer. I joined AEPSC as a Substation Engineer in 2006. In 2007, I transferred to Transmission Planning, where I advanced through increasing levels of responsibility. In December 2018, I assumed the position of Managing Director of Transmission Planning. I have been a registered Professional Engineer in the state of Ohio since 2009.

Q. WHAT ARE YOUR RESPONSIBILITIES AS MANAGING DIRECTOR OF TRANSMISSION PLANNING?

A. My responsibilities include organizing and managing all activities related to assessing the adequacy of AEP's and its operating companies' transmission network, including within the Southwest Power Pool (SPP) Regional Transmission Organization (RTO) region, to meet customers' needs in a reliable, cost-effective, and environmentally compatible manner.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE OR BEEN AN EXPERT WITNESS IN PROCEEDINGS BEFORE REGULATORY BODIES?

A. Yes, I have testified before the Public Utilities Commission of Ohio, the Maryland Public Service Commission, and the Pennsylvania Public Utility Commission, and I have submitted testimony before the Public Service Commission of Kentucky, the Indiana Utility Regulatory Commission, and the Michigan Public Service Commission on behalf of various electric operating companies of AEP.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to support this application by Southwestern Electric Power Company (SWEPCO or the Company) with respect to the evaluation performed to analyze deliverability and transmission congestion risk of the Request for Proposal (RFP) bids and of the selected group of wind facilities (Selected Wind Facilities). Specifically, in my testimony I will:

- Describe the threshold deliverability analysis performed, pursuant to the RFP, for purposes of relative assessment of the RFP bids;
- Describe the congestion analysis performed; and
- Explain the Company's evaluation of transmission solutions to mitigate future potential congestion

III. THRESHOLD DELIVERABILITY ANALYSIS OF WIND RFP BIDS

Q. PLEASE PROVIDE AN OVERVIEW OF THE THRESHOLD ANALYSIS PERFORMED TO DETERMINE THE DELIVERABILITY RISK OF THE WIND FACILITIES PROPOSED IN RESPONSE TO THE COMPANY'S RFP.

A. The Company performed an analysis to identify the deliverability risk of each of the RFP bids based upon the location of each generator's interconnection to the SPP transmission grid. This analysis allowed the generator's performance capability to be stress-tested for credible conditions faced by the transmission system. The objective of the analysis was communicated to interested bidders in Section 9.1.12 of the Eligibility and Threshold Requirements of the RFP, which stated;

> the Project must not be located in an area in which deliverability is determined by the Company to be either severely limited or non-deliverable to the AEP West load zone, based upon (a) its analysis of various groupings of Proposals of dependence on transmission lines as determined through a current distribution factor method ("DFAX") analysis performed by the Company, and (b) a First Contingency Incremental Transfer Capability ("FCITC") analysis performed by the Company on each area;
>
> DFAX is further described in the RFP as:
>
> > ... an analysis of each generator to determine individual responses to transmission lines across SPP. Based on the response factors, generators will be aggregated into generator clusters.
>
> FCITC is further described in the RFP as:
>
> > ... an analysis of the generator clusters, which Bidders plan to interconnect, which will measure the amount which could be transferred from the Bidder's interconnection area to the AEP West load zone while ensuring that the system is operated respecting operating limits that will not be exceeded in the event of certain outages (or contingency).

Q. ARE GENERATION DELIVERABILITY STUDIES A COMMON INDUSTRY PRACTICE?

A. Yes. In fact, SPP performs an annual deliverability study to determine the available deliverable capacity of resources registered in the SPP Integrated Marketplace. Likewise, other RTOs and Independent System Operators (ISOs), such as the PJM Interconnection, CAISO, and MISO perform similar studies. FCITC and DFAX assessments are industry standard methods to quantify the impact of generation delivery on the grid.

Q. PLEASE EXPLAIN WHY A THRESHOLD DELIVERABILITY ANALYSIS WAS A NECESSARY PART OF THE RFP EVALUATION PROCESS.

A. For electricity users to realize the *full* benefits of low-cost power, such as that produced by a wind turbine, the power must have an efficient and unconstrained delivery pathway to the user (*i.e.*, load). Fundamentally, the Company's deliverability analysis provided an assessment of relative risk and sensitivity to transmission congestion and curtailment under future system conditions for the wind generators that responded to the RFP. Typically, generators that are located directly adjacent to load will have a greater potential to deliver power efficiently and at a relatively lower risk of disturbance from changes in future transmission system conditions or addition of new generation. However, for dispersed wind generation connected to the SPP grid across a wide geographic area, as was the case with the responses to the Company's RFP, understanding the potential risk associated with these locational differences was important. As further described in the direct testimony of Company witness Pfeifenberger, due to the physical constraints of the transmission system and the occurrence of transmission outages, the SPP transmission grid is not always capable of delivering power from a specific generating source to a specific load zone, resulting in potential economic underperformance of wind generation assets. Ultimately, through the Company's deliverability analysis, the RFP bids identified as being located in areas with greater risk of unsuccessful energy delivery to SWEPCO customers were eliminated during the RFP evaluation process.

Q. WHY IS THE CONGESTION ANALYSIS DISCUSSED LATER IN YOUR TESTIMONY NOT ENOUGH TO DETERMINE THE DELIVERABILITY AND CONGESTION RISK?

A. Congestion analysis, which uses PROMOD®, an integrated electric generation and transmission market simulation software tool, is not adequate by itself to fully capture the risk of congestion[1] and curtailment[2] since such analysis is simulating a perfect day-ahead market under normalized and perfectly predictable load and system conditions. In essence, in PROMOD simulations, demand is normal and known for every hour, the transmission system does not encounter any outages, and the outage and generation schedule of all generating units is known in advance for the entire year along with their associated energy market bids. As a result, the congestion and curtailment risk identified by such a simulation is understated compared to what may be realized in the real market, where multiple transmission lines may be out of service at any given time, generation maintenance schedules are not predictable, wind and solar profiles may vary, and demand may be much higher or lower than normal. Furthermore, considering the number of computational parameters that a market efficiency tool such as PROMOD needs to satisfy to produce results, the number of flow gates (pairs of monitored elements and contingencies) is

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[1] Congestion is a condition that arises on the transmission system when one or more restrictions prevents the economic dispatch of electric energy from serving loads Economic dispatch is meeting system demand at the lowest possible cost

[2] Curtailment is the reduction in the output of a generator from what it could otherwise produce given available resources (*e g.*, wind or sunlight), typically on an involuntary basis due to system limitations

necessarily limited to a very small number compared to potential contingencies that could occur and result in system constraints. As a result, not all credible events and their impacts are evaluated, which is why a threshold deliverability analysis needs to be performed to fully understand the risk of congestion and curtailment.

Q. WHY WAS DFAX ANALYSIS PERFORMED TO GROUP GENERATORS INTO CLUSTERS?

A. It is imperative that not only the impact of individual generating resources is known but a realistic impact of multiple generating units producing energy at the same time in an area is also evaluated. In a region like SPP, where the amount of proposed wind generation is more than the current and forecasted peak demand, scaling all generation to full output will produce unrealistic impacts as the amount of generation dispatched under such a scenario will be significantly higher than current and forecasted demand. Similarly, only scaling one generator at a time masks impacts to the grid of various combinations of dispatch that are expected during real-time operation. A DFAX analysis can determine the impact of generation dispatch without scaling the generation or load to an unreasonable amount. A DFAX analysis determines generators that have a similar contribution to the same transmission circuits and gives transmission planners the ability to cluster generators with similar responses to the grid to further analyze the impact of the cluster and risk of congestion and curtailment under credible transmission outages in a specific area.

Q. PLEASE EXPLAIN THE OUTPUT OF THE DFAX ANALYSIS.

A. Using power flow models developed by SPP for its generator interconnection studies, the Company performed a system-wide DFAX analysis of wind generators requesting interconnection to the SPP. The Company derived the distribution factors of all the wind generator interconnection locations on the transmission facilities that have a voltage rating of 100 kV and above from power flow models. Distribution factors represent the change in power flows on a transmission facility due to an incremental injection at a generator bus. Using the distribution factors derived from these power flow models, the Company then grouped all of the wind generation located in SPP into a total of nine clusters based upon their sensitivity to the same transmission elements on the SPP grid. Only four of the nine clusters included a generator that bid into the RFP.

Q. PLEASE PROVIDE AN OVERVIEW OF THE NEXT STEP IN THE COMPANY'S DELIVERABILITY ANALYSIS, THE FCITC ANALYSIS.

A. FCITC analysis is an industry standard analysis performed to determine the available transmission capacity to deliver energy from a generating unit, a set of generating units or a zone to a particular load, a set of loads or a zone. The Company performed an FCITC analysis on the four clusters that included the RFP wind generators. In this method, the wind output of the cluster under study was increased from 20% of nameplate capacity to 100% of nameplate capacity while the generation resources in the AEP west zone were proportionally scaled down. These transfers are simulated under system normal and contingency conditions to determine the amount of power that can be transferred over the transmission system in a reliable manner *i.e.*, without violating transmission system limits.

Q. WHAT MODELING ASSUMPTIONS WERE USED IN THE FCITC ANALYSIS?

A. To perform the FCITC analysis, the Company used the models developed by SPP for its Definitive Interconnection System Impact Study (DISIS) that evaluates generation interconnection requests received during the DISIS Cluster Window. Specifically, the Company used the models developed for evaluating Energy Resource Interconnection

Service (ERIS) requests. The Company ensured that network upgrades identified by SPP to connect ERIS were included in the model.

Q. WHAT WERE THE RESULTS OF THE FCITC ANALYSIS?

A. Two of the four clusters that contained wind generation bids were identified as having a significant risk of power transfer limitations as generators in those clusters were unable to deliver incremental energy to AEP West Load Zone under reasonable outage scenarios. The two clusters with limitations were generally located in the panhandle and southeast part of Oklahoma.

Q. WERE ANY RFP BIDS ELIMINATED BASED ON THIS FCITC ANALYSIS?

A. Yes, per Section 9.1.12 of the Eligibility and Threshold Requirements of the RFP, the Company eliminated four projects (five total bids[3]) from these clusters from further consideration due to the deliverability thresholds identified in the Company's analysis. Three of these projects were located in a cluster with zero megawatts of deliverability, and the fourth was eliminated as its standalone bid exceeded the maximum deliverability limit for the entire cluster.

IV. CONGESTION ANALYSIS

Q. DID THE COMPANY PERFORM ANY ADDITIONAL TRANSMISSION ANALYSIS TO EVALUATE THE POTENTIAL ECONOMIC PERFORMANCE OF THE RFP BIDS?

A. Yes, pursuant to Section 9.2.1.1 in the RFP, after the threshold review the Company performed a Transmission Congestion Screening Analysis, which included the

[3] One of the projects eliminated included two bid variations.

development of a congestion and marginal loss projection for each RFP bid, using PROMOD. The Company utilized the latest available models developed by SPP for its Integrated Transmission Planning (ITP) studies. These models included the most up-to-date topology of the grid and included assumptions that were vetted and approved by SPP stakeholders for years 2024 and 2029. As further discussed in the direct testimony of witness Pfeifenberger, the Company used the SPP stakeholder-vetted base case assumptions without modification, except for the addition of wind generators that bid into the RFP, but were not in the SPP base case. The impacts of transmission facilities planned to be upgraded as part of any added generator's network upgrades identified in their specific SPP system impact study were also included in economic evaluations.

Q. HOW WERE THE CONGESTION AND LOSS COMPONENTS USED FOR THE BID ANALYSIS?

A. The congestion and loss component differentials between the individual wind sites and SPP's AEP West load zone from the 2024 and 2029 economic models were used to estimate the 30-year congestion and loss costs associated with each RFP wind resource. The calculation of the estimated future congestion and loss-related costs is explained in the testimony of witness Sheilendranath. These congestion and loss costs were then provided to witness Torpey to evaluate the Levelized Adjusted Cost of Energy (LACOE).

V. GEN-TIE PLANNING AND COSTING ANALYSIS FOR RFP EVALUATION

Q. PLEASE PROVIDE AN OVERVIEW OF THE GEN-TIE PLANNING AND COSTING ANALYSIS FOR THE RFP EVALUATION.

A. As discussed in the direct testimony of witness Pfeifenberger, congestion in wind-rich areas of SPP is highly volatile and the risk associated with congestion could be significant depending on the future portfolio of generation and changes to the transmission grid. The Company believes it prudent for SPP to propose new transmission and upgrades to existing infrastructure to address congestion management needs across the SPP system. However, the timing and magnitude of such transmission upgrades is uncertain. Given a multitude of factors that may impact the congestion forecast, as further discussed in the direct testimony of witness Pfeifenberger, the Company believed it prudent to also analyze the cost of directly connecting the RFP wind generators to the AEP West Load Zone in Tulsa, via a gen-tie to mitigate future congestion and curtailment risk. In essence, the gen-tie solution will only be deployed if forecasted congestion costs become significant and SPP is unable to mitigate the congestion, thus exposing SWEPCO customers to additional costs exceeding the cost of a gen-tie.

Q. IS IT REASONABLE TO EVALUATE THE RISK THAT SPP WILL NOT TIMELY ADDRESS CONGESTION?

A. Yes. From a risk perspective, it is reasonable to consider that SPP may not address congestion in a timely manner considering such upgrades require SPP stakeholders' and board approval. It is also possible that SPP's attempt to reduce broader system-wide congestion will not adequately address individual wind generator congestion situations. The Company needs to ensure that the Selected Wind Facilities will provide benefits to customers for a wide range of credible circumstances and that the cost of mitigating congestion does not render the portfolio uneconomic for SWEPCO customers.

Q. HOW WERE PLANNING SCOPES AND COST ESTIMATES DETERMINED FOR THE RFP BID EVALUATION GEN-TIE ANALYSIS?

A. Using the clusters identified in the DFAX analysis described above, the Company identified the scope of gen-tie solutions that would connect the RFP wind generation for each DFAX cluster to the 345kV transmission grid in the Tulsa, Oklahoma area. The Tulsa 345kV transmission system is a robust transmission network capable of delivering power cost-effectively to the AEP West Load zone with the expectation of relatively few network upgrades, making it a clear choice as the interconnection location for the relative evaluation of the RFP wind generators. Upon identification of the gen-tie scopes, the Company estimated capital costs and ongoing O&M costs for each solution on a per-mile and per-unit basis to be used for all generators in the RFP. Additional gen-tie sensitivities were analyzed, connecting certain wind facilities that were geographically proximate even though they were in other clusters to the AEP West Load Zone, to further evaluate and optimize the final portfolio of wind farms. As further discussed by witness Godfrey, the gen-tie revenue requirements and congestion and loss cost forecasts for each RFP generator were given a 50 percent weighting each and then added to the Levelized Cost of Energy (LCOE) to determine the LACOE for each RFP bid, which was considered in the bid selection process.

Q. WHY WAS THE 50/50 WEIGHTING SELECTED?

A. As mentioned earlier, congestion in wind-rich areas can be highly volatile. Congestion may decrease in the future if SPP builds transmission between wind-rich areas of SPP and load centers such as Tulsa. On the other hand, congestion could significantly increase if fossil-based generation, near major load centers, retires or the SPP does not act to resolve or limit market congestion. To ensure equal consideration of each scenario, the Company used 50% / 50% weighting for congestion and losses and gen-tie costs, respectively, to properly capture the risk that the location of each RFP wind project poses to SWEPCO customers.

VI. GEN-TIE PLANNING AND COST ANALYSIS FOR CUSTOMER BENEFITS ANALYSIS

Q. PLEASE DESCRIBE THE GEN-TIE ANALYSIS PERFORMED FOR PURPOSES OF THE CUSTOMER BENEFITS ANALYSIS.

A. After the Selected Wind Facilities were chosen, the projected SWEPCO customer benefits derived from those facilities were analyzed for various sensitivities. These customer benefit sensitivities are included as exhibits to witness Torpey's direct testimony. One such customer benefits scenario analyzed by the Company, which is analogous to the analysis performed for the RFP bid evaluation process described above, included the cost of a gen–tie solution. For the gen-tie customer benefits scenario, no congestion from the wind farms to Tulsa was assumed after the in-service date of the line, but the cost of a gen-tie was included.

Q. DID THE COMPANY ASSUME ANY TRANSMISSION UPGRADES IN ITS CONGESTION ANALYSIS OF THE SELECTED WIND FACILITIES?

A. Yes. For the scenarios that did not assume gen-tie, all future needs identified by the SPP in its 2019 ITP Study were assumed resolved by transmission upgrades identified by SPP in the future. Modifications to the SPP base case were made to align with the assumption that the SPP would address its future congestion needs. This case is referred to in the testimony of Company witness Pfeifenberger as the "Base Case."

For the scenario assuming a gen-tie , the Company utilized the SPP base case which includes only currently approved future transmission projects, and network upgrades needed to interconnect the Selected Wind Facilities, without addressing additional SPP ITP needs. This case is referred to in the testimony of Company witness Pfeifenberger as the "No-SPP-Upgrade Case."

Q. PLEASE FURTHER DESCRIBE THE GEN-TIE ANALYSIS PERFORMED AS A SENSITIVITY FOR THE CUSTOMER BENEFITS ANALYSIS.

A. Based upon the location of the Selected Wind Facilities, the Company further refined the scope and cost estimate identified in the RFP evaluation process for an optimized gen-tie configuration that would connect the Selected Wind Facilities to the AEP West Load zone in the Tulsa, OK area. These estimated costs were escalated to an assumed in-service year of 2026, which assumed a five-year period where congestion and SPP actions could be monitored before any gen-tie need would be assessed. The results of this analysis were provided to Company witness Torpey for his economic evaluation of the Selected Wind Facilities.

Q. IS THE COMPANY PROPOSING A GEN-TIE SOLUTION IN THIS FILING?

A. No. At this time, SPP system conditions do not indicate the need for a gen-tie solution for the Selected Wind Facilities. Any future construction of a gen-tie or other transmission upgrade(s) to mitigate congestion and curtailment risk would need to be supported by the economics at that time with consideration of the current state of the SPP transmission system, as discussed by Company witness Brice. However, this option is available for the

Company to use as a mitigation option against future congestion and curtailment risk, if necessary.

Q. DID YOU PROVIDE ANY OTHER INFORMATION FOR THE CUSTOMER BENEFITS ANALYSIS?

A. Yes, I also provided witness Torpey a forecast of the Company's ability to hedge against congestion using Transmission Congestion Rights (TCRs). I proposed that the Company assume up to 25% of congestion is hedged using TCRs. The Company is entitled to a portion of SPP's Auction Revenue Rights (ARRs) as an SPP Load Serving Entity. These ARRs may be converted to TCRs for specific source and sink combinations. However, if multiple entities try to convert ARRs to TCRs for the same source and sink combination, or if the source-sink combination paths are oversubscribed by other TCR trading entities, SPP will not be able to honor all the conversion requests, as the requests may not all pass SPP's Simultaneous Feasibility Test for the requested paths. Specifically, The Simultaneous Feasibility Test determines if all the requested TCRs are feasible at the same time. In case there is lack of available transmission capability between the source and sink, the requesting entities may not be able to successfully convert the ARRs to TCRs even when there is significant congestion between the source and sink. Based on the deliverability analysis that was performed under my supervision, the Selected Wind Facilities demonstrated significant deliverability to AEP West Zone. As a result, in a scenario where these Wind Facilities experience congestion, it is more likely that a significant portion of that congestion could be hedged using TCRs. I believe 25% is a reasonable number to utilize for the benefits calculation.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

PUC DOCKET NO. ________

PUBLIC UTILITY COMMISSION OF TEXAS

APPLICATION OF

SOUTHWESTERN ELECTRIC POWER COMPANY

FOR CERTIFICATE OF CONVENIENCE AND NECESSITY

AUTHORIZATION AND RELATED RELIEF FOR

THE ACQUISITION OF WIND GENERATION FACILITIES

DIRECT TESTIMONY OF

JOHN F. TORPEY

FOR

SOUTHWESTERN ELECTRIC POWER COMPANY

JULY 15, 2019

TESTIMONY INDEX

EXHIBITS

EXHIBIT	DESCRIPTION
EXHIBIT JFT-1	SWEPCO Arkansas & Louisiana Draft 2018 Integrated Resource Plan
EXHIBIT JFT-2	Request for Proposal Screening - Confidential
EXHIBIT JFT-3	Benefits of Selected Wind Facilities
EXHIBIT JFT-4	Natural Gas Price and Additional Sensitivities

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION IN THE COMPANY, AND BUSINESS ADDRESS.

A. My name is John F. Torpey, and I am employed as Managing Director - Resource Planning and Operational Analysis for American Electric Power Service Corporation (AEPSC). AEPSC supplies engineering, financing, accounting, planning, and advisory services to the eleven electric operating companies of American Electric Power Company, Inc. (AEP), including Southwestern Electric Power Company (SWEPCO or the Company). My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received a Bachelor of Engineering from The Cooper Union for the Advancement of Science and Art (New York) in 1979 and a Master of Business Administration from Saint John's University (New York) in 1984. In addition, in 1995, I completed the American Electric Power System Management Development Program at The Ohio State University, and in 2000, I completed the Darden Partnership Program at the Darden Graduate School of Business Administration, University of Virginia.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND.

In 1979, I was employed by AEPSC as a Design Engineer in the Structural Design Department. In 1985, I became the Project Controls Engineer for the Zimmer Conversion Project and then for the Gavin Flue Gas Desulfurization (FGD) Retrofit Project. I became Manager of the Controls Services Department in 1994, with responsibility for capital and expense budgeting, and maintenance outage planning for the AEP generating plants. I held various managerial positions in the AEPSC generation organization related to planning, budgeting, and cost control. In 2004, I became the Director of Corporate Budgeting in the Corporate Planning and Budgeting Department, and in 2007 became Director - Integrated Resource Planning. I assumed my current position in January 2018.

I am a Professional Engineer registered in the State of Ohio and a Certified Management Accountant. I have been an adjunct instructor at Franklin University (Ohio) since 2006 and have taught classes in the Accounting program and the Energy Management program.

Q. WHAT ARE YOUR CURRENT RESPONSIBILITIES?

A. I am primarily responsible for the supervision and administration of long-term generation resource planning and analysis for AEP operating companies including SWEPCO. In such capacity, I coordinate the use of short- and long-term generation production costing and other resource planning models used in the ultimate development of operating and capital budget forecasts and integrated resource plan (IRP) filings for the Company and its AEP affiliates. I oversee the economic evaluation of responses to requests for proposals (RFP) for new generation resources, and I regularly monitor actual performance and oversee the preparation of forecasted information for use in regulatory proceedings.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes. I have testified or provided testimony on behalf of SWEPCO affiliates Ohio Power Company before the Public Utilities Commission of Ohio, Indiana Michigan

Power Company before the Michigan Public Service Commission and the Indiana Utility Regulatory Commission, Appalachian Power Company (APCo) and Wheeling Power Company before the Public Service Commission of West Virginia, and APCo before the Virginia State Corporation Commission.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony discusses the Company's Integrated Resource Plan (IRP), its identification of potentially cost effective wind generation additions, which led to its request for proposals (RFP) for wind generation, and the economic analysis of the bids received in the RFP. In addition, my testimony quantifies the benefits of SWEPCO's proposal to acquire 810 MW of the three proposed wind facilities (1,485 MW total) in this case (Selected Wind Facilities), which represents a 54.5% share. SWEPCO's sister company, Public Service Company of Oklahoma (PSO), will acquire the remaining 675 MW (45.5%) share of the Selected Wind Facilities, subject to regulatory approval.

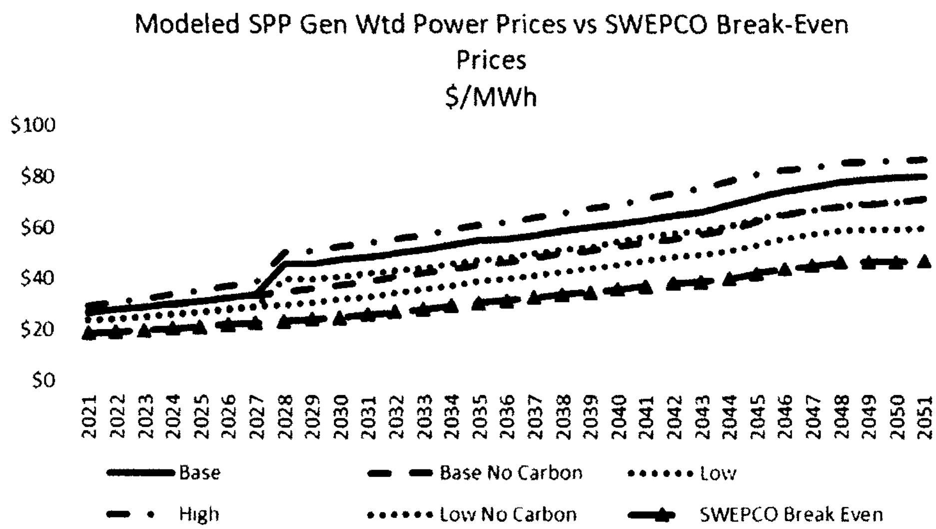
Using the Company's Base fundamental forecast that assumes a cost on carbon emissions beginning in 2028, the Selected Wind Facilities are forecasted to provide SWEPCO's customers savings over the 31-year project life of approximately $588 million on a net present value (NPV) basis, or $2,120 million on a nominal basis. Using the same Base fundamental forecast, excluding the future carbon dioxide cost from the forecast, SWEPCO's customers are expected to realize a savings over the 31-year project life of approximately $415 million on an NPV basis or $1,540 million on a nominal basis. These forecasts are sponsored by Company witness Bletzacker. Indeed, the Selected Wind Facilities are forecasted to provide SWEPCO's customers substantial savings under a wide range of future scenarios at their expected level of performance (P50) as summarized in Table 1.

Table 1: Benefits of Selected Wind Facilities – All Fundamental Forecasts and P50 Capacity Factor

SWEPCO			
Amounts in Millions	31 Year NPV	PTC Period - First 11 years Nominal Total	Full 31 Year Nominal Total
P50 Capacity Factor Cases			
High Gas With CO2	$741	$526	$2,595
Base Gas With CO2	$588	$424	$2,120
Base Gas Without CO2	$415	$323	$1,540
Low Gas With CO2	$414	$298	$1,612
Low Gas Without CO2	$253	$214	$1,055

The savings shown in Table 1 are calculated using a range of forecasted energy prices described by Company witness Bletzacker. For the Selected Wind Facilities the Company calculated the energy prices necessary to provide a customer benefit of $0 on a NPV basis. Figure 1, below, shows that the energy prices indicated in the Low Gas Without Carbon fundamentals forecast would have to be reduced by more than 20% for the Selected Wind Facilities to break-even on an NPV basis. The break-even power price in Figure 1 is well below all of the Company's forecasted power prices.

Figure 1



The balance of my testimony will cover the analysis and evaluations performed by my group as it relates to SWEPCO's resource plan, RFP and Customer Benefits Analysis. Specifically, my testimony will:

1) Provide an overview of SWEPCO's most recent IRP.
2) Describe the RFP Economic Analysis.
3) Describe the Customer Benefits Analysis of the Selected Wind Facilities.
4) Describe the results of natural gas price, capacity factor, and other sensitivity analyses of the Customer Benefits Analysis.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes, I am supporting the following exhibits:

- JFT-1 SWEPCO (Arkansas & Louisiana Draft) 2018 IRP
- JFT-2 Request for Proposal Screening - Confidential
- JFT-3 Benefits of Selected Wind Facilities

- JFT-4 Natural Gas Price and Additional Sensitivities

III. IRP OVERVIEW

Q. WHAT IS THE PURPOSE OF AN IRP?

A. An IRP is a planning document that outlines how an electric utility plans to meet its obligation to provide safe, reliable, cost-effective electric service to its customers through a wide array of supply-side and demand-side resource alternatives. An IRP typically includes a forecast of customer electricity load, generation capacity, energy production, and generating unit retirements, and a description of how the utility intends to fulfill its capacity reserve obligation. In accordance with Arkansas and Louisiana Public Service Commission requirements, SWEPCO completed and submitted its most recent IRP, which covers a twenty-year planning period, in December 2018. EXHIBIT JFT-1 is a link to the IRP.

Q. DESCRIBE THE RESULTS OF THE 2018 SWEPCO ARKANSAS IRP.

A. The 2018 IRP forecasts SWEPCO to have adequate capacity to meet its SPP load obligations through 2026 at which time it will experience a capacity shortfall of 22 MW, increasing to 348 MW by 2030 and 1,886 MW by 2038 if it does not acquire new capacity. This shortfall is due to modest load growth, the expiration of existing purchase power agreements, and the retirements of older gas steam units. The 2018 SWEPCO IRP shows that while coal capacity makes up 43 percent of SWEPCO's generating capacity, 83 percent of its energy comes from coal-fired generation.

To address the future capacity deficit, provide customer energy cost savings, and diversify its generation sources, the SWEPCO IRP's Preferred Plan recommends various alternatives including energy efficiency measures, new wind generation resources beginning in 2022, utility-scale solar additions beginning in 2025, and new natural gas-fired generation in 2037. As it relates to this filing, SWEPCO's Preferred Plan includes 1200 MW of cumulative additional wind resources coming online by 2023. These additions will provide SWEPCO with sufficient capacity to meet its SPP reserve margin requirements, will reduce the percent of coal-generated energy to 44 percent by 2038, and will reduce customer costs. The capacity additions in SWEPCO's Preferred Plan IRP are set out in Table 2 below.

Table 2: SWEPCO 2018 IRP Cumulative Capacity Additions (MW)

Preferred Plan		**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
Base Commodity, Base Load	Base/Intermediate																	373	1,119
	Solar (Nameplate)					150	300	450	600	750	1,000	1,150	1,300	1,300	1,300	1,300	1,300	1,300	1,300
	Wind (Nameplate)		600	1,200	1,400	1,400	1,400	1,400	1,400	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
	Energy Efficiency	15	21	20	25	23	20	17	13	12	11	10	7	5	3	3	2	2	1
	VVO	24	24	24	24	37	37	37	37	37	37	37	37	48	48	48	48	48	48
	Distr. Gen. (Firm)	4	4	4	4	4	5	5	5	5	5	6	6	6	6	7	7	7	8
Capacity Reserves (MW) Above SPP Requirement without New Additions		**419**	**386**	**258**	**237**	**109**	**(22)**	**(101)**	**(121)**	**(159)**	**(348)**	**(376)**	**(404)**	**(497)**	**(521)**	**(552)**	**(946)**	**(1,330)**	**(1,886)**
Capacity Reserves (MW) Above SPP Requirement with New Additions		**462**	**465**	**366**	**360**	**409**	**439**	**423**	**448**	**490**	**359**	**379**	**548**	**522**	**531**	**534**	**140**	**129**	**318**

Base/Intermediate=NGCC; Peaking=NGCT, AD; CHP=Combined Heat & Power; VVO=Volt VAR Optimization; DG=Distributed Generation

Q. DESCRIBE THE INPUTS AND METHODOLOGY USED TO DEVELOP SWEPCO'S DRAFT IRP.

A. Inputs to the IRP include:

- the Company's load forecast including capacity and energy requirements;
- reserve margin requirements for the SPP;
- future costs, operating characteristics, retirement dates, and forecasted performance of existing resources, including Company-owned generation and purchase power agreements;
- a projection of fuel costs, emission costs, short-term capacity purchase costs, and market energy prices; and

- cost and performance characteristics of potential alternatives for new supply- and demand-side resources, including constraints on the amount and timing of new resource additions.

This data is input to the PLEXOS® model, which calculates the optimal portfolio of resources that will meet the Company's capacity obligation at the lowest cost. PLEXOS is a widely accepted model that AEPSC uses to forecast its operating companies' production costs and to develop optimal resource plan solutions. Optimized portfolios are created under a variety of pricing forecasts (*e.g.*, low gas, high gas), and are used as the basis for the Company's Preferred Plan.

Q. IS THE SWEPCO IRP RESULT CONSISTENT WITH OTHER IRPs FILED BY AEP OPERATING COMPANIES THAT OPERATE IN SPP?

A. Yes. In December 2018, SWEPCO filed an IRP in Arkansas with a resource plan identical to the plan in the Draft SWEPCO Louisiana IRP. Also, in December 2018, SWEPCO affiliate PSO filed an IRP in Oklahoma. As a planning assumption, the SWEPCO and PSO IRPs constrained wind resource additions through the planning period to a maximum of roughly 40 percent of each company's energy production to prevent the model from selecting an amount of wind resources that could be inconsistent with maintaining SPP grid stability. The model selected the maximum amount of wind resources as part of the lowest-cost solution to meet customers' needs.

Q. SINCE SWEPCO AND PSO FILED THEIR RESPECTIVE IRPs AND DRAFT IRP HAVE ANY INPUT ASSUMPTIONS CHANGED?

A. Yes. The IRP modeling represents the latest and best information the Company has at a point in time. The 2018 SWEPCO Arkansas IRP, draft SWEPCO Louisiana IRP, and PSO IRP were all prepared using an August 2018 vintage fundamentals forecast. The final SWEPCO Louisiana IRP, which will be filed in August 2019, and the PLEXOS analysis for the filing in this case are using a more recent April 2019 fundamentals forecast which includes generally lower natural gas and SPP market energy prices than the 2018 forecast. The SWEPCO load forecast has been updated and shows slower load growth than the 2018 load forecast used in the IRP, delaying the need for new capacity in SWEPCO until 2030. Initial optimization modeling runs for the final 2019 SWEPCO Louisiana IRP show that the addition of wind resources in 2022 and 2023 continue to provide economic value for customers and will be included in SWEPCO's Preferred Plan.

Q. HOW DOES SWEPCO'S WIND RFP RELATE TO THE COMPANY'S 2018 FINAL AND 2019 DRAFT IRPs?

A. SWEPCO's 2018 and 2019 IRPs identified wind resources as economic and began adding wind resources in 2022. In the IRP, by adding 1200 MW of new wind resources by 2023, and an additional 200 MW in 2024, SWEPCO's wind generation would equate to approximately 40% of its total generation. In each commodity price scenario analyzed for the IRP, 1200 MW of wind by 2023 was determined to be part of the optimal plan. The wind resources selected by the model in 2022 and 2023 were eligible for the 80% and 60% PTC, respectively, which made them economic resources. This result was a key driver in the decision for SWEPCO to issue an RFP for wind resources. The Selected Wind Facilities procured through the RFP would provide SWEPCO 810 MW of the 1200 MW of new wind resources called for by the IRP.

IV. RFP BID ECONOMIC ANALYSIS

Q. DID THE COMPANY RANK THE BIDS RECEIVED IN THE RFP BASED ON AN ECONOMIC ANALYSIS OF THOSE BIDS?

A. Yes, in part. Consistent with the RFP, 90% of the bid ranking was based on an economic evaluation and the remaining 10% was based on non-price factors. The project economic rankings are shown in CONFIDENTIAL EXHIBIT JFT-2. This information was provided to witness Godfrey to determine the final portfolio of Selected Wind Facilities.

Q. EXPLAIN THE PROCESS USED TO EVALUATE THE RESPONSES TO THE COMPANY'S RFP.

A. As further discussed by witness Godfrey, responses to the RFP that met the Eligibility and Threshold Requirements (RFP §9.1), then moved into the Detailed Analysis (RFP §9.2) phase of the RFP that included the 1) Economic Analysis (RFP §9.2.1) and 2) the Non-Price Factor Analysis (RFP §9.2.2). The Economic Analysis included calculating three metrics for each bid, the Levelized Cost of Energy (LCOE), the Levelized Adjusted Cost of Energy (LACOE), and the Levelized Net Cost of Energy (LNCOE).

First, the LCOE, which only represents the project cost and ignores delivery cost to the customer, was calculated for each bid. Congestion and losses costs and the potential cost for congestion mitigation, based on input from Company witnesses Sheilendranath and Ali, were added to determine the LACOE for each bid. Finally, LNCOE, while not part of the bid ranking, was calculated for each bid as a preliminary indicator to show that the proposals resulted in savings to customers. To calculate LNCOE, avoided energy and capacity costs were subtracted from the LACOE for each bid. The LNCOE represents the levelized net revenue requirement to the customer including a credit to account for capacity value. The capacity value is the same on a $/MW basis for all bids. Each of these metrics results in a $/MWh unit of measure allowing for comparison of different sized (MW) projects with varying capital costs ($) and expected annual generation (MWh). As discussed by Company witness Godfrey, the results of the Economic Analysis and Non-Price Factor Analysis were used in determining the final bid selection.

Q. HOW WAS THE LCOE FOR EACH BID CALCULATED?

A. The LCOE was determined by dividing the present value of the revenue requirements ($) for a bid by the generation (MWh) over the study period, producing a levelized cost of energy for each project expressed in $/MWh. The present value of the revenue requirements for a project is determined from the annual revenue requirements for each of the 30 years the project is assumed to be in service. Annual revenue requirements take into account the following factors:

- Purchase price
- Owners' costs and contingency
- Book depreciation
- Tax depreciation (including Modified Accelerated Cost Recovery System, or MACRS)
- Flow-through treatment of deferred state income tax
- SWEPCO Weighted Average Cost of Capital
- Federal PTCs, net of Deferred Tax Asset (DTA) carrying costs
- Land lease costs
- Operation and Maintenance (O&M) costs
- Property taxes

The generation for a project is determined from the sum of the expected annual energy output over the life of the project. The expected annual energy, which does account for an extra day during leap year, was provided by witness Godfrey and is discussed in detail in his testimony.

Q. HOW DID YOU CALCULATE THE LACOE FOR THE RFP BID ECONOMIC ANALYSIS?

A. The LACOE takes into account two additional factors, in addition to the LCOE. First is the costs of congestion and transmission line losses. Congestion and line losses costs were developed by Company witness Sheilendranath. The other factor is the cost of a potential future generation-tie line to alleviate unexpectedly higher congestion costs if such congestion costs were not mitigated by the SPP. Generation-tie line (gen-tie) costs were provided to me by company witness Ali.

To treat all bid proposals equitably, the LCOEs for each bid were adjusted for the average of levelized congestion and line loss costs and levelized gen-tie costs. The following shows how LACOE is calculated:

Levelized Cost of Energy (LCOE)
+ 50% Levelized Cost of Congestion and Line Losses
<u>+ 50% Levelized Cost of Potential Gen-Tie</u>
Total Levelized Adjusted Cost of Energy (LACOE)

Q. HOW DID YOU CALCULATE THE LNCOE?

A. The LNCOE was determined by subtracting the avoided energy and capacity costs from the LACOE. Avoided energy costs represent the energy value of the output from each bid into the SPP market. Avoided energy costs were based on projected SPP energy prices used in SWEPCO's 2018 IRP.

Avoided capacity costs represent an assumed capacity contribution for each project at the assumed price for capacity in the SPP used in the 2018 IRP. For the RFP Economic Analysis the value of capacity is based on an assumed $/MW-day value attributed to the firm capacity of each project. This adds an equivalent $/MW capacity value to each project. The capacity benefit attributed to the Selected Wind Facilities is based on a more robust analysis described in the Customer Benefits Analysis section of my testimony.

Q. HOW DID THE COMPANY DEVELOP THE CONGESTION AND LOSSES INPUTS TO THE RFP ANALYSIS?

A. For the RFP Economic Analysis, PROMOD, a proprietary model used by the SPP in transmission planning, was used to calculate congestion costs and losses. Witness Sheilendranath discusses how the PROMOD tool was used to develop congestion costs and loss projections for each of the RFP bids.

V. CUSTOMER BENEFITS OF SELECTED WIND FACILITIES

Q. WHAT ARE THE FORECASTED BENEFITS AND COSTS OF THE SELECTED WIND FACILITIES?

A. Table 3 contains the forecasted benefits, projected costs, and resulting net customer savings of the Selected Wind Facilities assuming a P50 capacity factor (meaning it is equally probable (50%) that the wind output would be greater or lesser than the P50 value) under the Company's Base Case fundamentals forecast that both includes and excludes a carbon burden. EXHIBIT JFT-3, pages 1-2, shows the annual costs and benefits of this case.

Table 3: Net Benefits of Selected Wind Facilities

Base Gas with Carbon and P50 Capacity Factor

Year	31 Year NPV	Total 31 Year Nominal
Production Cost Savings Excluding Congestion/Losses	$1,680	$5,185
Congestion and Losses	($322)	($893)
Capacity Value	$70	$311
Production Tax Credits (grossed up net of DTA)	$507	$750
Wind Facility Revenue Requirement	($1,348)	($3,233)
Net Customer Benefits	**$588**	**$2,120**

Base Gas with No Carbon and P50 Capacity Factor

Year	31 Year NPV	Total 31 Year Nominal
Production Cost Savings Excluding Congestion/Losses	$1,467	$4,473
Congestion and Losses	($269)	($725)
Capacity Value	$57	$274
Production Tax Credits (grossed up net of DTA)	$507	$750
Wind Facility Revenue Requirement	($1,348)	($3,233)
Net Customer Benefits	**$415**	**$1,540**

Q. EXPLAIN HOW EACH OF THE COMPONENTS IN TABLE 3 ARE CALCULATED OR DERIVED.

A. The project benefits and costs are calculated or derived as follows:

- Production Cost Savings were determined by my group and equal the difference in cost for: fuel, purchased power, other variable costs, and increased off-system sales, between a portfolio that includes the Selected Wind Facilities and a baseline portfolio that excludes them.
- Congestion and losses costs were provided by Company witness Sheilendranath.
- Capacity Value is the savings from deferring capacity additions (new construction or purchases) due to the addition of the Selected Wind Facilities.

- PTCs - grossed up and net of DTA carrying costs are the value of production tax credits for each MWh of wind generation during the facilities' first ten years of production. Because the PTC is a tax credit, it is equivalent to a revenue reduction equal to the PTC divided by 1 – the tax rate, which is referred to as a tax gross up. The DTA cost represents the carrying charge on the deferred tax asset balance and is supported by Company witnesses Multer and Hollis.
- Revenue requirements were provided by Company witness Aaron based on the installed capital costs plus operations and maintenance costs from Company witnesses Godfrey and DeRuntz.

Q. EXPLAIN THE PROCESS USED TO EVALUATE THE ECONOMIC BENEFIT TO CUSTOMERS OF THE SELECTED WIND FACILITIES.

A. While the initial RFP Economic Analysis indicated that the bids would provide customer benefits under the Company's assumed avoided energy and capacity values, along with expected congestion and loss costs, a more robust analysis of the customer benefits of the Selected Wind Facilities was subsequently conducted using the PLEXOS model. The PLEXOS model utilizes a forecast for the Company's generating units cost of energy (e.g., fuel, fuel handling, variable operations and maintenance, consumable costs and emission allowance costs), scheduled maintenance outages, and forced outages, along with forecasted market prices of energy to determine forecasted generation output, costs, and revenues.

The model compares the total hourly energy output of SWEPCO's generation resources against the hourly internal load and energy requirement of SWEPCO. To the extent that the resources exceed the load, the model determines the surplus generation sold at the hourly generation price. To the extent that the load exceeds the resources, the model determines the deficit purchase at the market load price. Consequently, the Production Cost Savings includes the cost of production less the cost of purchases, plus the revenues from additional off-system sales (OSS) less the OSS margins retained by SWEPCO.

To determine the net customer benefits of the Selected Wind Facilities, the Company developed both a case that assumed the Selected Wind Facilities for SWEPCO were not added (the Baseline Case), and a change-case scenario that included the Selected Wind Facilities (Project Case). The Company then compared the difference or "delta" between these two cases for the period modeled, 2021 to 2051. In a methodology consistent with the development of the SWEPCO 2018 IRP, natural gas combined cycle (NGCC) units, natural gas peaking units, solar resources, and short-term market purchases were optimally added as needed to SWEPCO's resources in both the Baseline Case and Project Case throughout the period to maintain the 12% reserve margin as required by the SPP. The benefits also include the Selected Wind Facilities' capacity value, which were determined using the PLEXOS model.

In summary, the adjusted production cost savings were added to the avoided capacity value and the grossed-up value of PTCs net of DTA carrying costs to arrive at the total economic benefit. Project costs including the wind project revenue requirements and congestion and transmission line loss costs were then subtracted from the total benefit to arrive at an annual net benefit to customers. The present value of all costs and benefits is then calculated.

Q. EXPLAIN THE METHODOLOGY USED TO MODEL THE SELECTED WIND FACILITIES' ENERGY VALUE.

A. As explained by Company witness Pfeifenberger, the PROMOD, Aurora, and PLEXOS models were used to calculate system energy costs and benefits. Company witness Sheilendranath explains how PROMOD simulations produced a projection of AEP West Load Zone locational marginal prices (LMPs) and congestion and loss effects for 2024 and 2029. The results of this simulation were interpolated and extrapolated over 31 years and then incorporated into PLEXOS. The PLEXOS simulation of the Company's resources was based on a 31-year forecast and includes the impact the Selected Wind Facilities have on the production cost versus the Baseline Case. The Plexos model computed different optimal portfolios of future resources for each of the Fundamental forecast cases presented in Table 1.

Q. DOES THE COMPANY'S METHODOLOGY RECOGNIZE THE COMMISSION AUTHORIZED OFF-SYSTEM SALES SHARING ARRANGEMENT FOR SWEPCO LOUISIANA?

A. Yes. The adjusted production cost takes into account that 90% of OSS margin is returned to the customers.

Q. HOW DOES THE COMPANY'S METHODOLOGY ACCOUNT FOR THE SELECTED WIND FACILITIES' CAPACITY VALUE?

A. For the SWEPCO share of the Selected Wind Facilities, the Company assumed a firm capacity rating of 15% of the Selected Wind Facilities' nameplate rating, representing a capacity contribution of 123 MW. SWEPCO's current wind resources have a MW weighted aggregate capacity rating of 17.0% of nameplate. Because wind is an intermittent resource, meaning the output from a wind project will vary throughout the day, the SPP has developed a methodology to calculate the capacity value a wind project provides using actual or expected performance data.

The capacity from the Selected Wind Facilities is expected to defer or reduce future capacity requirements of the Company. As such, the NPV savings associated with the delay in future capacity additions was included as a benefit of the Selected Wind Facilities. This capacity benefit calculation compares the present value of the fixed costs and carrying costs of resource additions from a PLEXOS-optimized portfolio that included the capacity contribution of Selected Wind Facilities (the Project Case) to a PLEXOS-optimized portfolio that excluded that capacity contribution (the Baseline Case). The annual difference in fixed cost and carrying costs between these two portfolios was discounted and summed to arrive at the NPV of the Selected Wind Facilities' capacity benefit. The PLEXOS model computed different optimal portfolios of future resources for each of the Fundamental forecast cases presented in Table 1.

Q. DID THE COMPANY DETERMINE A NATURAL GAS PRICE AND SPP MARKET ENERGY PRICE AT WHICH THE COSTS AND BENEFITS OF THE SELECTED WIND FACILITIES ARE PROJECTED TO BE THE SAME (I.E., A BREAK-EVEN PRICE)?

A. Yes. Figure 1 shown earlier in my testimony shows the break-even energy prices compared to the generation weighted fundamentals forecast prices. Company witness Bletzacker calculated a break-even natural gas price.

Q. HOW DID THE COMPANY PREPARE ITS BREAK-EVEN ANALYSIS FOR THE SELECTED WIND FACILITIES?

A. The Company determined the reduction in production costs savings required to result in a zero NPV of customer benefits (*i.e.*, what reduction in production cost savings result in the bottom line of Table 3, Net Customer Benefits, equaling \$0). This reduction approximates the reduction in around-the-clock energy prices that result in a break-even result. I provided Witness Bletzacker with the energy price reduction (assuming no costs for carbon emissions) which he used to calculate the reduction in natural gas prices that would achieve that energy price reduction. This process determined the natural gas and energy prices at which the costs and benefits of the Selected Wind Facilities would break-even.

Q. HOW DOES THE BREAK-EVEN PRICE COMPARE TO THE FUNDAMENTALS FORECAST USED IN THE COMPANY'S CUSTOMER BENEFIT CALCULATION?

A. For the Customer Benefit to equal zero, average energy prices would have to be reduced by 32% from the Company's Base No Carbon Case fundamentals forecast.

Q. HOW WILL INCLUSION OF THE SELECTED WIND FACILITIES INTO THE COMPANY'S RESOURCE MIX IMPACT SWEPCO'S EXISTING GENERATING FLEET?

A. The addition of the Selected Wind Facilities will reduce the volume of energy SWEPCO must buy from the SPP market on an annual basis and allow SWEPCO to sell more energy into the SPP market throughout the year. SWEPCO assigns the lower cost wind energy to customers and higher cost energy from its existing fossil assets to OSS. The change in generation from the existing SWEPCO fleet generation is minimal. The addition of the Selected Wind Facilities is not expected to have a significant impact on the SWEPCO Gen Hub energy prices under the assumption that additional wind facilities would be built at some point in the future.

VI. SENSITIVITIES

Q. WHAT SENSITIVITY ANALYSES DID YOU PERFORM?

A. The Company calculated customer savings for additional sensitivity analyses under a variety of pricing forecasts:

- A high gas (with a carbon cost) and a low gas with and without carbon pricing forecast at expected (P50) performance;
- A lower capacity factor (the P95 scenario) using high, base, and low gas pricing with a carbon cost, and base gas pricing without carbon; and
- A higher congestion cost scenario including the addition of a gen-tie in 2026 to relieve that congestion at base pricing with and without carbon using P50 performance, and at base pricing without a carbon cost at P95 performance.

EXHIBIT JFT-3 contains the annual forecasted benefits, projected costs, and resulting net customer savings of the Selected Wind Facilities under all sensitivities.

Q. WHAT DOES THE COMPANY'S ANALYSIS DEMONSTRATE CONCERNING THE BENEFITS OF THE SELECTED WIND FACILITIES UNDER THESE VARIOUS PRICING AND WIND PERFORMANCE SCENARIOS?

A. The results of the P50 performance scenarios are included in Table 1 and are summarized in EXHIBIT JFT-4. The Selected Wind Facilities will provide an economic benefit to customers under all of the P50 pricing sensitivities analyzed by the Company.

The P95 cases represent the level at which there is a 95% chance the actual output of the Selected Wind Facilities will be greater than the level assumed for each case. These scenarios assume a 38.1% capacity factor and 2,705 GWh per year for

SWEPCO, which amounts to 13.4% less wind energy from the Selected Wind Facilities than in the P50 scenario. The P95 scenario analyses, summarized in EXHIBIT JFT-4, demonstrate that the Selected Wind Facilities will provide an economic benefit to customers even under a variety of adverse or unlikely conditions.

Q. WHAT DOES THE COMPANY'S ANALYSIS DEMONSTRATE CONCERNING THE BENEFITS OF THE SELECTED WIND FACILITIES, IF HIGHER CONGESTION COSTS LEAD TO THE ADDITION OF A GEN-TIE?

A. Over the 31-year life of the Selected Wind Facilities, assuming congestion costs were high enough to warrant building a gen-tie by 2026, the Selected Wind Facilities would still result in customer benefits even when the cost of a gen-tie is included. The gen-tie cases, as shown in EXHIBIT JFT-4, were analyzed using base pricing forecasts with and without a carbon cost at the P50 performance level, and the base with no carbon pricing forecast at the P95 performance level. The results of the Gen-Tie scenarios show that a gen-tie preserves customer benefits if congestion costs increase significantly.

The absolute benefit values in the Gen-Tie cases are not directly comparable to the lower congestion cases without a gen-tie because the Gen-Tie cases assume higher congestion costs as described by witness Sheilendranath. The no Gen-Tie scenarios presented in Table 1 reflect a level of congestion costs consistent with the assumption that SPP will undertake certain transmission projects to address congestion as described by Company witness Ali. In the scenarios analyzed in Table 1, a gen-tie is not necessary to provide customer benefits.

VI. CONCLUSION

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. The Company's IRP identified wind as an economic resource alternative under multiple pricing forecasts that convinced the Company to issue an RFP for wind resources. The responses to the RFP were evaluated using an Economic Analysis and Non-Price Factor Analysis ranking. The RFP Economic Analysis was a key input in determining the Selected Wind Facilities. An additional economic analysis of the Selected Wind Facilities versus a Baseline portfolio excluding those Facilities shows customer benefits under a wide range of assumptions and sensitivities, including lower-bound energy and natural gas price forecasts or addition of a gen-tie if it became necessary. The Selected Wind Facilities have a break-even average energy price that is 32% below the Company's base (no-carbon) energy price forecast. The economic analysis was performed with widely used modeling tools and was based on reasonable inputs and assumptions.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

The SWEPCO-Arkansas IRP was filed in docket number 17-011-U on December 14, 2018.

http://www.apscservices.info/pdf/07/07-011-U_32_2.pdf

The SWEPCO-Louisiana draft IRP was filed in docket number I-34715 on January 11, 2019. The final report will be filed in August 2019.

http://lpscstar.louisiana.gov/star/portal/lpsc/PSC/PSCDocumentDetailsPage.aspx?DocumentId=1fee9798-4a80-4927-930a-2a2c3e8ae688&Class=Filing

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2019 Wind RFP - SWEPCO 810 MW SHARE OF PROJECT

P50 15% CAPACITY CREDIT BASE GAS WITH CARBON CUSTOMER COSTS AND BENEFITS VS MARKET - No Tie Line

$ in Millions (Nominal unless otherwise indicated)

Year	NPV	Total 31 Yr. Nominal	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1 Production Cost Savings Excluding Congestion/Losses	$1,680	$5,185	$12	$86	$89	$94	$98	$102	$105	$143	$144	$148	$152
2 Congestion and Losses	($322)	($893)	($3)	($18)	($19)	($20)	($22)	($25)	($27)	($30)	($32)	($32)	($32)
3 Capacity Value	$70	$311	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4 Production Tax Credits, Grossed Up	$630	$963	$15	$88	$91	$92	$95	$95	$98	$98	$102	$102	$87
5 Deferred Tax Asset Carrying Charges	($123)	($212)	($0)	($4)	($9)	($13)	($17)	($19)	($21)	($22)	($23)	($24)	($24)
6 Wind Facility Revenue Requirement	($1,348)	($3,233)	($17)	($132)	($130)	($130)	($128)	($127)	($126)	($124)	($123)	($121)	($119)
7 Tie Line Revenue Requirement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8. Total Net Customer Benefits/(Cost)	**$588**	**$2,120**	**$6**	**$21**	**$23**	**$22**	**$26**	**$26**	**$30**	**$66**	**$68**	**$73**	**$64**

Year	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
1 Production Cost Savings Excluding Congestion/Losses	$156	$160	$165	$171	$173	$177	$181	$185	$191	$196	$202	$205	$214
2 Congestion and Losses	($32)	($32)	($32)	($32)	($32)	($32)	($32)	($32)	($32)	($32)	($32)	($32)	($32)
3 Capacity Value	$0	$0	$0	$0	$0	$1	$54	$55	($1)	$56	$55	($3)	($1)
4 Production Tax Credits, Grossed Up	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5 Deferred Tax Asset Carrying Charges	($20)	($12)	($3)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6 Wind Facility Revenue Requirement	($116)	($114)	($112)	($110)	($108)	($106)	($104)	($102)	($100)	($98)	($97)	($95)	($93)
7 Tie Line Revenue Requirement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8. Total Net Customer Benefits/(Cost)	**($12)**	**$2**	**$18**	**$29**	**$33**	**$41**	**$99**	**$107**	**$58**	**$122**	**$128**	**$76**	**$88**

Year	2045	2046	2047	2048	2049	2050	2051
1 Production Cost Savings Excluding Congestion/Losses	$223	$228	$238	$244	$243	$246	$214
2 Congestion and Losses	($32)	($32)	($32)	($32)	($32)	($32)	($27)
3 Capacity Value	($0)	($1)	$50	$46	($3)	($2)	$4
4 Production Tax Credits, Grossed Up	$0	$0	$0	$0	$0	$0	$0
5 Deferred Tax Asset Carrying Charges	$0	$0	$0	$0	$0	$0	$0
6 Wind Facility Revenue Requirement	($91)	($89)	($88)	($86)	($85)	($86)	($81)
7 Tie Line Revenue Requirement	$0	$0	$0	$0	$0	$0	$0
8. Total Net Customer Benefits/(Cost)	**$99**	**$107**	**$169**	**$172**	**$123**	**$126**	**$111**

Benefits of Selected Wind Facilities (Base P50)

Benefits of Selected Wind Facilities (Base No Carbon P50)

2019 Wind RFP - SWEPCO 810 MW SHARE OF PROJECT
P50 15% CAPACITY CREDIT BASE GAS NO CARBON CUSTOMER COSTS AND BENEFITS VS MARKET - No Tie Line
$ in Millions (Nominal unless otherwise indicated)

Year	NPV	Total 31 Yr. Nominal	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1 Production Cost Savings Excluding Congestion/Losses	$1,467	$4,473	$12	$86	$89	$93	$97	$101	$104	$108	$111	$116	$120
2 Congestion and Losses	($269)	($725)	($3)	($18)	($19)	($20)	($21)	($22)	($23)	($24)	($25)	($25)	($25)
3 Capacity Value	$57	$274	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4 Production Tax Credits, Grossed Up	$630	$963	$15	$88	$91	$92	$95	$95	$98	$98	$102	$102	$87
5 Deferred Tax Asset Carrying Charges	($123)	($212)	($0)	($4)	($9)	($13)	($17)	($19)	($21)	($22)	($23)	($24)	($24)
6 Wind Facility Revenue Requirement	($1,348)	($3,233)	($17)	($132)	($130)	($130)	($128)	($127)	($126)	($124)	($123)	($121)	($119)
7 Tie Line Revenue Requirement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8. Total Net Customer Benefits/(Cost)	**$415**	**$1,540**	**$6**	**$21**	**$23**	**$21**	**$27**	**$28**	**$33**	**$36**	**$42**	**$47**	**$39**

Year	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
1 Production Cost Savings Excluding Congestion/Losses	$125	$129	$139	$145	$147	$153	$156	$154	$162	$164	$171	$177	$183
2 Congestion and Losses	($25)	($25)	($25)	($25)	($25)	($25)	($25)	($25)	($25)	($25)	($25)	($25)	($25)
3 Capacity Value	$0	$0	($7)	($7)	($8)	($6)	$47	$55	($0)	$55	$52	($1)	$2
4 Production Tax Credits, Grossed Up	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5 Deferred Tax Asset Carrying Charges	($20)	($12)	($3)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6 Wind Facility Revenue Requirement	($116)	($114)	($112)	($110)	($108)	($106)	($104)	($102)	($100)	($98)	($97)	($95)	($93)
7 Tie Line Revenue Requirement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8. Total Net Customer Benefits/(Cost)	**($37)**	**($21)**	**($9)**	**$3**	**$7**	**$16**	**$74**	**$82**	**$37**	**$96**	**$101**	**$56**	**$67**

Year	2045	2046	2047	2048	2049	2050	2051
1 Production Cost Savings Excluding Congestion/Losses	$194	$200	$206	$211	$214	$216	$189
2 Congestion and Losses	($25)	($25)	($25)	($25)	($25)	($25)	($21)
3 Capacity Value	$3	$1	$47	$44	($3)	($2)	$4
4 Production Tax Credits, Grossed Up	$0	$0	$0	$0	$0	$0	$0
5 Deferred Tax Asset Carrying Charges	$0	$0	$0	$0	$0	$0	$0
6 Wind Facility Revenue Requirement	($91)	($89)	($88)	($86)	($85)	($86)	($81)
7 Tie Line Revenue Requirement	$0	$0	$0	$0	$0	$0	$0
8. Total Net Customer Benefits/(Cost)	**$80**	**$87**	**$140**	**$143**	**$101**	**$104**	**$91**

2019 Wind RFP - SWEPCO 810 MW SHARE OF PROJECT

P50 15% CAPACITY CREDIT LOW GAS WITH CARBON CUSTOMER COSTS AND BENEFITS VS MARKET - No Tie Line

$ in Millions (Nominal unless otherwise indicated)

Year	NPV	Total 31 Yr Nominal	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1 Production Cost Savings Excluding Congestion/Losses	$1,470	$4,555	$10	$75	$78	$80	$84	$86	$89	$125	$125	$128	$131
2 Congestion and Losses	($278)	($774)	($3)	($16)	($17)	($17)	($19)	($21)	($23)	($26)	($28)	($28)	($28)
3 Capacity Value	$63	$313	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4 Production Tax Credits, Grossed Up	$630	$963	$15	$88	$91	$92	$95	$95	$98	$98	$102	$102	$87
5 Deferred Tax Asset Carrying Charges	($123)	($212)	($0)	($4)	($9)	($13)	($17)	($19)	($21)	($22)	($23)	($24)	($24)
6 Wind Facility Revenue Requirement	($1,348)	($3,233)	($17)	($132)	($130)	($130)	($128)	($127)	($126)	($124)	($123)	($121)	($119)
7 Tie Line Revenue Requirement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8. Total Net Customer Benefits/(Cost)	**$414**	**$1,612**	**$6**	**$12**	**$14**	**$11**	**$15**	**$14**	**$17**	**$51**	**$53**	**$57**	**$48**

Year	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
1 Production Cost Savings Excluding Congestion/Losses	$135	$137	$148	$153	$156	$160	$164	$162	$168	$172	$177	$181	$187
2 Congestion and Losses	($28)	($28)	($28)	($28)	($28)	($28)	($28)	($28)	($28)	($28)	($28)	($28)	($28)
3 Capacity Value	$0	$0	($7)	($7)	($8)	($6)	$47	$55	($1)	$57	$56	($4)	($3)
4 Production Tax Credits, Grossed Up	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5 Deferred Tax Asset Carrying Charges	($20)	($12)	($3)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6 Wind Facility Revenue Requirement	($116)	($114)	($112)	($110)	($108)	($106)	($104)	($102)	($100)	($98)	($97)	($95)	($93)
7 Tie Line Revenue Requirement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8. Total Net Customer Benefits/(Cost)	**($29)**	**($16)**	**($2)**	**$8**	**$13**	**$21**	**$80**	**$88**	**$39**	**$103**	**$109**	**$55**	**$64**

Year	2045	2046	2047	2048	2049	2050	2051
1 Production Cost Savings Excluding Congestion/Losses	$195	$200	$207	$213	$217	$219	$191
2 Congestion and Losses	($28)	($28)	($28)	($28)	($28)	($28)	($23)
3 Capacity Value	($2)	($3)	$58	$57	$9	$9	$6
4. Production Tax Credits, Grossed Up	$0	$0	$0	$0	$0	$0	$0
5 Deferred Tax Asset Carrying Charges	$0	$0	$0	$0	$0	$0	$0
6 Wind Facility Revenue Requirement	($91)	($89)	($88)	($86)	($85)	($86)	($81)
7 Tie Line Revenue Requirement	$0	$0	$0	$0	$0	$0	$0
8. Total Net Customer Benefits/(Cost)	**$74**	**$81**	**$149**	**$156**	**$113**	**$115**	**$94**

2019 Wind RFP - SWEPCO 810 MW SHARE OF PROJECT
P50 15% CAPACITY CREDIT HIGH GAS WITH CARBON CUSTOMER COSTS AND BENEFITS VS MARKET - No Tie Line

$ in Millions (Nominal unless otherwise indicated)

Year	NPV	Total 31 Yr. Nominal	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1 Production Cost Savings Excluding Congestion/Losses	$1,872	$5,770	$13	$96	$100	$105	$110	$114	$119	$158	$159	$164	$168
2 Congestion and Losses	($358)	($994)	($3)	($21)	($21)	($22)	($25)	($28)	($30)	($33)	($35)	($35)	($35)
3 Capacity Value	$68	$301	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4 Production Tax Credits, Grossed Up	$630	$963	$15	$88	$91	$92	$95	$95	$98	$98	$102	$102	$87
5 Deferred Tax Asset Carrying Charges	($123)	($212)	($0)	($4)	($9)	($13)	($17)	($19)	($21)	($22)	($23)	($24)	($24)
6 Wind Facility Revenue Requirement	($1,348)	($3,233)	($17)	($132)	($130)	($130)	($128)	($127)	($126)	($124)	($123)	($121)	($119)
7 Tie Line Revenue Requirement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8. Total Net Customer Benefits/(Cost)	**$741**	**$2,595**	**$7**	**$28**	**$31**	**$30**	**$36**	**$36**	**$40**	**$78**	**$79**	**$85**	**$76**

Year	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
1 Production Cost Savings Excluding Congestion/Losses	$173	$176	$183	$189	$193	$198	$202	$207	$214	$220	$228	$233	$242
2 Congestion and Losses	($35)	($35)	($35)	($35)	($35)	($35)	($35)	($35)	($35)	($35)	($35)	($35)	($35)
3 Capacity Value	$0	$0	$0	$0	$0	$2	$51	$52	$1	$52	$48	$1	$6
4 Production Tax Credits, Grossed Up	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5 Deferred Tax Asset Carrying Charges	($20)	($12)	($3)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6 Wind Facility Revenue Requirement	($116)	($114)	($112)	($110)	($108)	($106)	($104)	($102)	($100)	($98)	($97)	($95)	($93)
7 Tie Line Revenue Requirement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8. Total Net Customer Benefits/(Cost)	**$0**	**$15**	**$32**	**$44**	**$50**	**$59**	**$113**	**$122**	**$80**	**$138**	**$144**	**$104**	**$120**

Year	2045	2046	2047	2048	2049	2050	2051
1 Production Cost Savings Excluding Congestion/Losses	$251	$255	$263	$270	$267	$268	$232
2 Congestion and Losses	($35)	($35)	($35)	($35)	($35)	($35)	($30)
3 Capacity Value	$7	$4	$38	$35	($1)	($1)	$6
4 Production Tax Credits, Grossed Up	$0	$0	$0	$0	$0	$0	$0
5 Deferred Tax Asset Carrying Charges	$0	$0	$0	$0	$0	$0	$0
6 Wind Facility Revenue Requirement	($91)	($89)	($88)	($86)	($85)	($86)	($81)
7 Tie Line Revenue Requirement	$0	$0	$0	$0	$0	$0	$0
8. Total Net Customer Benefits/(Cost)	**$132**	**$135**	**$178**	**$183**	**$146**	**$146**	**$127**

2019 Wind RFP - SWEPCO 810 MW SHARE OF PROJECT
P50 15% CAPACITY CREDIT LOW GAS NO CARBON CUSTOMER COSTS AND BENEFITS VS MARKET - No Tie Line

$ in Millions (Nominal unless otherwise indicated)

Year	NPV	Total 31 Yr. Nominal	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1 Production Cost Savings Excluding Congestion/Losses	$1,294	$4,072	$10	$75	$78	$81	$84	$88	$91	$93	$95	$99	$102
2 Congestion and Losses	($230)	($617)	($3)	($16)	($17)	($17)	($18)	($19)	($20)	($21)	($21)	($21)	($21)
3 Capacity Value	$29	$83	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4 Production Tax Credits, Grossed Up	$630	$963	$15	$88	$91	$92	$95	$95	$98	$98	$102	$102	$87
5 Deferred Tax Asset Carrying Charges	($123)	($212)	($0)	($4)	($9)	($13)	($17)	($19)	($21)	($22)	($23)	($24)	($24)
6 Wind Facility Revenue Requirement	($1,348)	($3,233)	($17)	($132)	($130)	($130)	($128)	($127)	($126)	($124)	($123)	($121)	($119)
7 Tie Line Revenue Requirement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8. Total Net Customer Benefits/(Cost)	**$253**	**$1,055**	**$6**	**$12**	**$14**	**$12**	**$17**	**$18**	**$22**	**$25**	**$30**	**$34**	**$25**

Year	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
1 Production Cost Savings Excluding Congestion/Losses	$106	$114	$118	$123	$126	$130	$133	$131	$138	$140	$145	$150	$156
2 Congestion and Losses	($21)	($21)	($21)	($21)	($21)	($21)	($21)	($21)	($21)	($21)	($21)	($21)	($21)
3 Capacity Value	$0	($7)	($7)	($7)	($7)	($6)	$47	$55	($1)	$57	$56	($3)	($2)
4 Production Tax Credits, Grossed Up	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5 Deferred Tax Asset Carrying Charges	($20)	($12)	($3)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6 Wind Facility Revenue Requirement	($116)	($114)	($112)	($110)	($108)	($106)	($104)	($102)	($100)	($98)	($97)	($95)	($93)
7 Tie Line Revenue Requirement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8. Total Net Customer Benefits/(Cost)	**($52)**	**($41)**	**($26)**	**($15)**	**($11)**	**($3)**	**$55**	**$63**	**$15**	**$77**	**$83**	**$31**	**$39**

Year	2045	2046	2047	2048	2049	2050	2051
1 Production Cost Savings Excluding Congestion/Losses	$164	$170	$222	$229	$233	$235	$212
2 Congestion and Losses	($21)	($21)	($21)	($21)	($21)	($21)	($18)
3 Capacity Value	($2)	($2)	$12	$11	($35)	($37)	($37)
4 Production Tax Credits, Grossed Up	$0	$0	$0	$0	$0	$0	$0
5 Deferred Tax Asset Carrying Charges	$0	$0	$0	$0	$0	$0	$0
6 Wind Facility Revenue Requirement	($91)	($89)	($88)	($86)	($85)	($86)	($81)
7 Tie Line Revenue Requirement	$0	$0	$0	$0	$0	$0	$0
8. Total Net Customer Benefits/(Cost)	**$49**	**$57**	**$126**	**$133**	**$92**	**$92**	**$76**

Benefits of Selected Wind Facilities (Low No Carbon P50)