Q. HAS THE COMPANY ANALYZED A CASE IN WHICH HIGHER CONGESTION WOULD MATERIALIZE IF THE SPP-ITP-IDENTIFIED TRANSMISSION NEEDS WERE NOT ADDRESSED?

A. Yes, given the uncertainty about the extent and timing of future SPP transmission upgrades, the Company has additionally run simulations with an SPP PROMOD case *without* upgrading (all but one) the SPP-ITP-identified transmission needs.[12] As would be expected, this "No-SPP-Upgrades Case" yields higher congestion charges than the "Base Case," given the lack of additional transmission upgrades. The No-SPP-Upgrade Case still yields lower congestion charges than what has been reflected in the Bid Evaluation Case, since the Bid Evaluation case includes an additional 3,400 MW of proposed wind projects that were not selected by the Company. As discussed in Company witness Torpey's testimony, the Company has used this No-SPP-Upgrades Case to evaluate customer benefits under a higher-congestion scenario in which it is assumed that congestion risk mitigation through a gen tie would become necessary.

Q. HOW DO THE PROJECTED 2024 AND 2029 CONGESTION ESTIMATES FROM THE SPP PROMOD MODEL COMPARE TO THE HISTORICAL CONGESTION LEVELS EXPERIENCED BY EXISTING WIND GENERATION IN SPP?

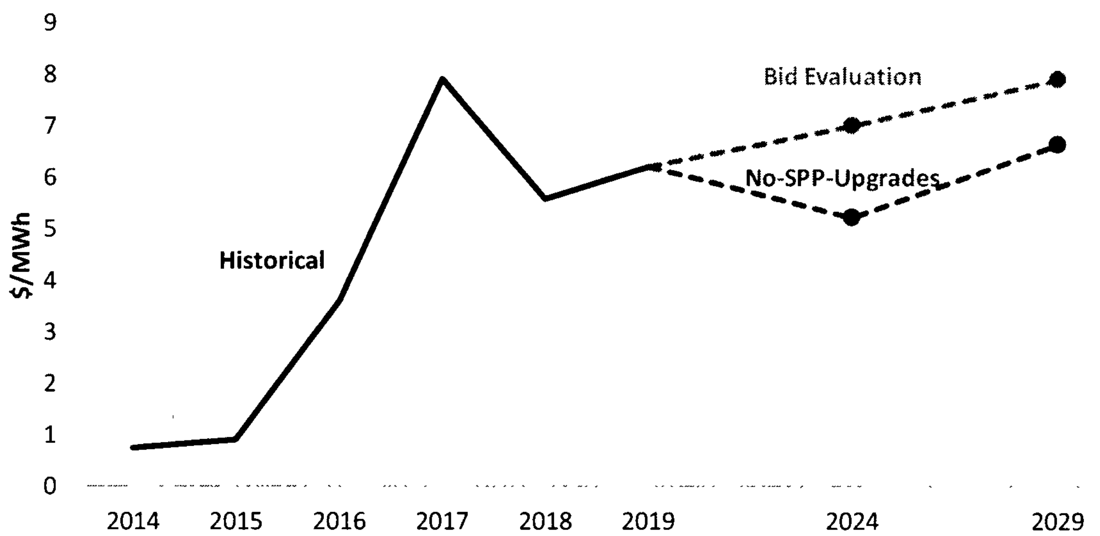
A. Figure 1~~Figure 1~~ below summarizes the simple annual average of hourly congestion charges between the AEP's existing Oklahoma wind facilities and SPP's

[12] As noted earlier, the company assumed in all cases that the 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 the transmission upgrade costs were expected to be low.

AEP-West load zone for both historical years (as previously reported in Table 1) and projected future years (as simulated in PROMOD). More specifically, these simple averages[13] of wind-to-AEP West load zone congestion costs are shown both for: (1) the actual historical real-time market outcomes for 2014 through (year to date) 2019; and (2) the 2024 and 2029 simulations results for AEP's existing Oklahoma wind facilities from the Base, No-SPP-Upgrades, and Bid Evaluation PROMOD cases. As shown, the historical average annual congestion charges between AEP's existing Oklahoma wind plants and the AEP West load zone (solid black line) have ranged from a low of less than $1/MWh in 2014 and 2016 to $8/MWh in 2017, before dropping to around $6/MWh in 2018 and (year to date) 2019—reflecting the congestion-reducing effect of SPP transmission additions that came online in recent years. As shown, the simulated future congestion levels are in the upper half of the historically-experienced range.

[13] Again, because hourly historical wind generation data is not publicly available for these wind facilities, the figure presents the simple averages over all hours of the year. Although this will understate the actual congestion costs faced by the owners of these wind facilities (because hours with higher wind generation will tend to have higher congestion charges), the simple averages nevertheless document congestion trends over time and allow for a comparison of historical and simulated congestion levels.

Figure 1: Historical and Simulated Wind-to-AEPW Congestion for Existing AEP Wind Facilities in Oklahoma
(Simple all-hours annual average, weighted by MW plant size)



Looking forward, the figure shows the SPP PROMOD simulation results for the three congestion scenarios simulated by the Company.

1. The "*Bid Evaluation Case*" results from the 2024 and 2029 SPP PROMOD cases used for RFP bid evaluation (the highest dashed line) show the highest simulated congestion charges because the case includes all wind facility bids received by the Company and reflects only transmission upgrades that SPP has identified in the modeled wind facilities' interconnection studies. As shown, these simulation results are at the high end of the historical range for existing Oklahoma wind facilities.

2. The "*Base Case*" simulation results for the 2024 and 2029 SPP PROMOD cases used for the customer benefit analysis (the lowest dashed line) show the lower congestion charges, reflecting (a) the addition of only the Selected Wind Facilities (beyond the wind facilities already in the SPP case), (b) transmission upgrades that SPP has identified in the Selected Wind Facilities' interconnection studies; as well as (c) the assumption that SPP would upgrade the transmission constraints it has identified through the currently-ongoing SPP ITP stakeholder process. As shown, the 2024 and 2029 results for this simulation show congestion charges that are approximately the average of historical congestion, reflecting the congestion-reducing impact of the assumed upgrades of the SPP-ITP-identified transmission constraints.

3. Finally, the "*No SPP Upgrades Case*" used by the Company for conducting the Customer Benefit Analysis (the middle dashed line) shows congestion results below those of the bid evaluation case but above the base case. As discussed further below, this higher-congestion case was used for Company witness Torpey's congestion risk mitigation scenario of the customer benefit analysis. This case shows congestion charges that are lower than the bid evaluation case, because only the three Selected Wind Facilities (*i.e.*, not all received bids) have been added beyond the wind additions reflected in the SPP cases. The congestion charges are above the Base Case results because this case assumes that, beyond the already-approved upgrades, none of the current SPP-ITP-identified transmission needs would be addressed—which, compared to the Base Case, would make it more likely that the congestion risk mitigation option evaluated by Company witness Torpey would need to be implemented.

Q. IS IT REASONABLE THAT 2024 CONGESTION LEVELS FOR THE BASE CASE WOULD BE BELOW THOSE RECENTLY EXPERIENCED?

A. Yes, it is. All SPP-approved transmission upgrades that are currently under development will be placed into service by the 2024 simulation year. This involves over $1.6 billion of transmission upgrades in 2019 through 2024.[14] Because the Base Case simulation further assumes that the additional transmission needs SPP has identified in its current ITP assessment would be addressed through additional upgrades as well, it is reasonable that congestion would be reduced below the recent historical levels.

Q. WHY IS CONGESTION INCREASING BETWEEN 2024 AND 2029 IN ALL THE SIMULATION CASES?

A. The estimated congestion level increases between 2024 and 2029. However, only a small portion of that increase will relate to additional wind generation development because SPP assumes that only 400 MW new wind facilities become

[14] See page 8 of Second Quarterly Project Tracking Report, April 2019 https://www.spp.org/documents/59868/q2%202019%20spp%20quarterly%20project%20tracking%20report.pdf

operational between 2024 and 2029 based on SPP Reference Case. Thus, much of the higher congestion charges are driven by higher generation redispatch costs. To illustrate this point, the simple average of monthly gas prices in the SPP Reference Case is $4.62/MMBtu in 2024 and is $5.44 in 2029, a 17.8% increase. Since congestion increases by 21.9% between the two years of the No-SPP-Upgrades Case, it suggests that the dominant driver of the shown congestion charge increase is accounted for by higher gas prices, which increase the redispatch cost. The other effects are likely accounted for by a combination of the added wind generation, significant new solar generation, and the retirements of some of the aging fossil generating plants in SPP projected for 2029.

Q. IF CONGESTION COSTS WERE TO INCREASE ABOVE PROJECTED LEVELS, WOULD IT BE MORE LIKELY THAT SPP WOULD UPGRADE THE CONSTRAINED TRANSMISSION FACILITIES?

A. Yes. In general, as congestion costs associated with specific transmission facilities increase, it will at some point become either cost effective to upgrade the constraining transmission facilities or necessary to upgrade some of the constrained facilities from a system reliability perspective. Whether and when SPP would identify and approve such further upgrades is uncertain, however, which creates the congestion and deliverability risks that the Company has considered in its RFP bid evaluation process. If congestion increases but SPP transmission upgrades are not implemented to address the higher congestion, the likelihood increases that the Company will need to mitigate that congestion through dedicated transmission upgrades, such as a gen-tie between the Selected Wind Facilities and the Company's Tulsa load center, as evaluated by Company witness Torpey.

Q. ARE CUSTOMERS FULLY EXPOSED TO THE PROJECTED WIND-TO-LOAD CONGESTION CHARGES?

A. No, they are not fully exposed to the congestion charges. Load serving entities are able to obtain from SPP allocations of some Transmission Congestion Rights (TCRs) that allow them to avoid (hedge at no cost) a portion of these congestion charges in the day-ahead market. Unfortunately, due to limited transmission capability and the high levels of wind generation developed in the region, it has been difficult to obtain sufficient TCR allocations for wind facilities from SPP. In addition, some of the congestion is experienced only in the real-time market, which cannot be hedged through TCRs. As noted by Company witness Ali, the Company forecasts that approximately 25% of its wind generation-related congestion costs could be hedged. The benefit of these congestion hedges is not reflected in the congestion costs reported in the summary charts and tables of my testimony, nor are they considered in the congestion cost and risk analysis during the RFP bid evaluation process. They are, however, reflected in the Company's customer benefits analysis (at the 25% hedge ratio).

Q. WHAT ARE THE SPP PROMOD ESTIMATES OF FUTURE CONGESTION AND LOSS-RELATED COSTS FOR THE SELECTED WIND FACILITIES BEFORE AND AFTER CONSIDERING THE LIKELY UPGRADES OF THE SPP-ITP-IDENTIFIED TRANSMISSION CONSTRAINTS?

A. Table 4~~Table 4~~ below shows congestion and loss-related costs for the Selected Wind Facilities based on the PROMOD results for the Base Case and No-SPP-Upgrades Case simulations.

Table 4: Simulated Wind-to-AEPW Congestion and Losses for the Three Selected Wind Facilities

($/MWh)	2024							
Selected Wind Facility	**Simple Avg**		**Gen-Weighted Avg**		**Simple Avg**		**Gen-Weighted Avg**	
	Congestion	**Losses**	**Congestion**	**Losses**	**Congestion**	**Losses**	**Congestion**	**Losses**
	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]
Base Case								
Average	*3.87*	*0.76*	*7.43*	*1.33*	*4.83*	*1.01*	*9.15*	*1.67*
Traverse	4.17	0.61	7.81	1.02	5.40	0.85	10.02	1.31
Maverick	3.31	0.73	6.30	1.35	4.05	0.97	7.61	1.68
Sundance	4.14	0.94	8.18	1.63	5.03	1.21	9.81	2.01
No-SPP-Upgrades Case								
Average	*4.85*	*0.74*	*9.25*	*1.28*	*6.15*	*0.98*	*11.27*	*1.60*
Traverse	7.05	0.59	12.80	0.98	8.94	0.82	15.69	1.26
Maverick	3.02	0.71	6.01	1.30	3.74	0.95	7.20	1.62
Sundance	4.47	0.91	8.94	1.56	5.78	1.16	10.94	1.92

Source and Notes:
2024 and 2029 PROMOD simulation outputs.
[B] & [D] & [F] & [H]: Average loss costs represent half of the wind-generation-weighted marginal loss charges for the wind resources.

Q. PLEASE SUMMARIZE THE OVERALL METHODOLOGY AND METRICS THE COMPANY USED FOR ITS CUSTOMER BENEFITS ANALYSIS.

A. As explained in the testimony of Company witness Torpey, the Company analyzed customer benefits associated with the three Selected Wind Facilities for thirteen cases covering a range of wholesale power market fundamentals (provided by Company witness Bletzacker), wind availability cases (provided by Company witness Godfrey), congestion risk mitigation cases, and a break-even case (estimated by

Company witness Torpey). These include customer benefits for 50th percentile (P50) annual wind generation for the following <u>five</u> wholesale-power-market fundamentals using the Base Case PROMOD congestion estimates:

1. a "base-gas/with-carbon" case (as the Company's base fundamentals case)
2. a "base-gas/no-carbon" case
3. a "low-gas/with-carbon" case
4. a "low-gas/no-carbon" case
5. a "high-gas/with-carbon" case

In addition to these five P50 cases reflecting Company witness Bletzacker's market fundamentals forecasts, the Company also developed four additional cases based on the five-year 95th percentile (P95)[15] wind production levels. As further explained by Company witness Torpey, these four P95 cases (also using the Base Case PROMOD congestion estimates) include:

6. a P95 case for "base-gas/with-carbon" market fundamentals
7. a P95 case for "base-gas/no-carbon" market fundamentals
8. a P95 case for "low-gas/with-carbon" market fundamentals
9. a P95 case for "high-gas/with-carbon" market fundamentals

As explained further by Company witness Torpey, an additional three cases were developed to evaluate customer benefits in a higher congestion scenario (using the "No-SPP-Upgrades" PROMOD congestion case) under which a generation tie line could be built cost effectively to mitigate the higher congestion costs. These three "Gen-Tie" cases include:

10. a P50 gen-tie case for "base-gas/with-carbon" market fundamentals

[15] Note that applying the 5-year P95 wind capacity values to the 30-year customer benefit analysis yields a conservatively low P95 estimate of 30-year customer benefits because the probability of achieving wind generation better than the 5-year P95 level is greater than 95% over a 30-year period (i.e., six consecutive five-year P95 low-wind periods).

11. a P50 gen-tie case for "base-gas/no-carbon" market fundamentals

12. a P95 gen-tie case for "base-gas/no-carbon" market fundamentals

And finally, to estimate how low natural gas prices and associated wholesale power market prices could be while still producing customer benefits sufficient to cover the Selected Wind Facilities' costs, Company witness Torpey also developed:

13. a "break even" case

Company witness Bletzacker also developed for this break-even case (reflecting P50 wind conditions) a break-even natural gas price estimate.

Q. HOW HAS COMPANY WITNESS TORPEY DETERMINED CUSTOMER BENEFITS?

A. As Company witness Torpey explains, he has used the Company's PLEXOS model to determine how the Company's energy- and capacity-related costs—including its generation dispatch, off system sales and wholesale market purchases—will be affected by the ownership and operation of the Selected Wind Facilities. PLEXOS simulates these costs separately for PSO and SWEPCO. To determine these PSO and SWEPCO net customer costs, PLEXOS uses as an input the wholesale power market prices for the AEP West load zone, PSO and SWEPCO conventional generation, as well as the congestion and loss costs associated with deliveries from the Selected Wind Facilities.

As Company witness Torpey explains, the customer benefits of purchasing the Selected Wind Facilities are then determined by comparing the (1) total customer costs *with* the purchase of the Selected Wind Facilities; to the (2) total customer costs *without* the purchase of the Selected Wind facilities.

Q. HOW DID THE COMPANY DETERMINE THE WHOLESALE-POWER MARKET PRICES AND CONGESTION-COST INPUTS FOR PLEXOS?

A. The Company used the wholesale power market prices from it "markets fundamentals forecasts," which are based on Company witness Bletzacker's wholesale power market simulations for the entire Eastern Interconnection, covering the eastern two-thirds of the United States. As Company witness Bletzacker explains in his testimony, these simulations with the Aurora Energy Market Simulation Model (AURORA) provide a wholesale market price forecast for the "SPP Central" region, but do not further differentiate wholesale power prices by location or simulate congestion costs within SPP. Since the congestion and loss-related costs of delivering power from the Selected Wind Facilities had to be considered, it was necessary to develop for each AURORA simulation of the market fundamentals forecast: (1) a consistent set of estimated congestion and loss costs of delivering wind generation from the Selected Wind Facilities; and (2) an estimate of how market prices for the AEP West load zone and PSO and SWEPCO conventional generation differ locationally from the larger "SPP Central" zone price simulated in AURORA.

Q. HOW HAS THE COMPANY DEVELOPED THE NECESSARY CONGESTION AND LOSS COSTS FOR ITS AURORA-BASED FUNDAMENTALS PROJECTIONS FOR SPP CENTRAL?

A. The Company has utilized its PROMOD locational market simulations to estimate congestion and loss costs as well as the locational differences in SPP wholesale market prices. I have previously explained how congestion and loss costs were projected using the SPP PROMOD Reference Case as modified by the Company for wind generation additions and transmission upgrades. As explained in the testimony of Company witness Sheilendranath, these PROMOD congestion and loss-related costs had to be scaled to the various AURORA-based market fundamentals forecasts in proportion to the difference between (1) the SPP Central prices in the PROMOD simulations and (2) the SPP Central prices from the AURORA-based market fundamentals cases listed earlier.

Q. WHY WAS IT NECESSARY AND REASONABLE TO COMBINE MULTIPLE MODELS—PROMOD, AURORA, AND PLEXOS—TO ESTIMATE CUSTOMER BENEFITS ASSOCIATED WITH THE THREE SELECTED WIND FACILITIES?

A. PROMOD, AURORA, and PLEXOS are simulation tools that can be employed to perform the type of forward-looking market simulations necessary to assess the benefits of the Selected Wind Facilities. However, in this case, all three simulation tools were necessary for a number of reasons.

The Company has been relying on AURORA to project long-term trends of multi-regional market prices and PLEXOS for analyzing the market performance of their individual Company resources and for evaluating expected market revenues and dispatch outcomes for resource planning and customer impact purposes. Relying on AURORA for projecting long-term trends of regional market prices is advantageous because AURORA employs a consistent set of market fundamentals assumptions, such as natural gas and coal prices, for the full range of long-term wholesale power market and fuel price scenarios that AEP companies use for all their long-term planning purposes across all of their service areas. The Company uses these AURORA-based fundamentals forecasts for a variety of resource planning purposes as explained by witness Bletzacker.

Relying on PLEXOS to estimate customer impacts for individual operating companies has several advantages. The model is set up to simulate many years of future market performance quickly and to link and provide input to customer rate impact assessments. Most importantly, unlike PROMOD, the PLEXOS model is set up to simulate PSO and SWEPCO individually, and therefore is able to assess changes in production costs, market purchase costs, off-system sales revenues, and other customer cost items at the operating-company level.

Unlike PROMOD, the AURORA and PLEXOS models are not set up to simulate transmission constraints or losses within the SPP footprint, which means they are unable to assess the extent to which wholesale power prices, congestion costs, and loss-related costs affect the delivered costs of generating resources, including the Selected Wind Facilities.

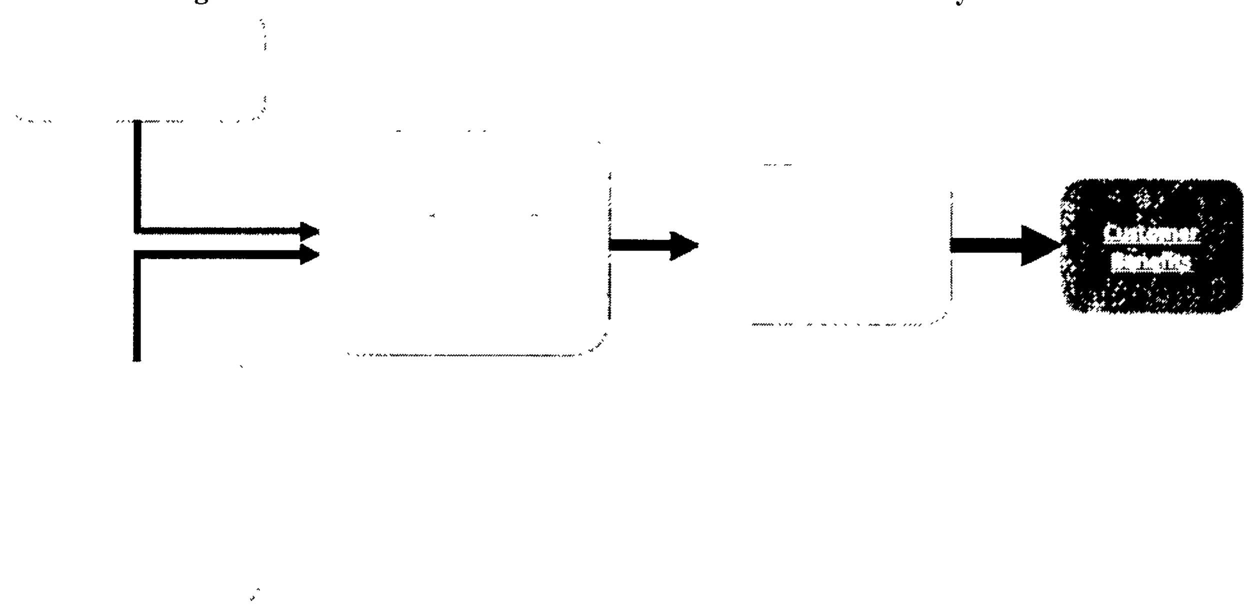
SPP's PROMOD models, as described earlier, simulate the entire SPP system (and surrounding market areas), including the full SPP transmission network and associated transmission constraints and losses. As stated previously in my testimony, transmission constraints have a significant effect on optimal SPP-wide market dispatch outcomes and the associated locational prices. Given that the large levels of wind generation are expected to grow further in the SPP region, it is important to capture the congestion and loss impacts of the transmission network on locational prices when evaluating the delivered costs of wind facilities. SPP's PROMOD model is, however, limited by the fact that it has been set up to analyze load-related impacts only for individual SPP transmission zones—such as the AEP West load zone, which aggregates both AEP companies (PSO and SWEPCO) as well as other public power entities—and without the level of detail that is required to separately assess customer impacts for each of the two AEP operating companies. In addition, SPP's PROMOD models are not conducive to quickly analyzing various sensitivities such as under varying long-term gas and coal price forecasts, and/or sensitizing with future carbon tax assumptions. The Company's AURORA model produces long-term regional price trends under varying sensitivities. Assessing the customer benefits under various market fundamentals sensitivities is essential for a comprehensive evaluation of the costs and benefits of the Selected Wind Facilities. Therefore, to assess the full benefits of the Selected Wind Facilities over the entire 30-year design lives and for each of the two companies, AURORA and PLEXOS were employed in conjunction with SPP's PROMOD models to capture the impact on the individual operating companies and to estimate the delivered cost and customer impact of the facilities.

Q. HOW HAS THE COMPANY DEVELOPED THE NECESSARY PLEXOS LOAD AND GENERATION MARKET PRICE INPUTS FROM ITS AURORA-BASED FUNDAMENTALS PROJECTION FOR SPP?

A. The Company's AURORA market fundamentals forecasts are for the AURORA-defined "SPP Central" zone. The PROMOD simulations were then used to estimate the extent to which the wholesale market prices for the AEP West load zone, PSO conventional generation, and SWEPCO conventional generation differed from market price projections for the SPP Central zone.

As explained in Company witness Sheilendranath's testimony, this was accomplished by scaling the PROMOD-based wholesale market price differences between SPP Central and the AEP load and generation locations based on the extent to which the level of market prices for SPP Central differ between the AURORA and PROMOD simulations. This scaling of PROMOD-based congestion and loss differences between SPP Central and AEP West load and the PSO and SWEPCO generation zones recognizes the SPP locational market price differences relative to SPP Central, but scales those differences up or down to be consistent with the extent to which AURORA market price forecasts for SPP Central are higher or lower than those for SPP Central in the SPP PROMOD simulations. How AURORA and PROMOD simulation results were combined by Company witness Sheilendranath to develop the necessary PLEXOS inputs is illustrated in Figure 2 below.

Figure 2: Simulation Models Used in Customer Benefit Analysis



Q. IS IT REASONABLE TO SCALE THE PROMOD CONGESTION AND LOCATIONAL MARKET PRICE DIFFERENTIAL BETWEEN AEP LOCATIONS AND SPP CENTRAL BASED ON THE LEVEL OF AURORA MARKET FUNDAMENTALS?

A. Yes, it is. Given a certain transmission network and installed generation base in SPP, the congestion and loss-related costs will primarily be a function of the overall level of market prices. If natural gas prices are higher, for example, not only will overall wholesale power prices be higher, but the cost of supplying losses and redispatching generation to manage congestion within the SPP footprint will be correspondingly higher as well. Since the difference in wholesale market prices between different locations in SPP is a direct function of congestion and loss-related charges, it is reasonable to scale the differences in locational market prices with the overall level of market prices.

Q. WHAT ARE THE PROMOD MARKET PRICE DIFFERENCES BETWEEN SPP CENTRAL AND THE AEP WEST LOAD ZONE?

A. As shown in Table 5 below, the simple average of wholesale power prices (locational marginal prices or LMPs) for the AEP West load zone are \$4–\$7/MWh above simulated SPP-Central[16] prices across the three sets of PROMOD simulations used by the Company. As shown, the simulations with higher average wind-related congestion levels (*e.g.*, the No-SPP-Upgrades Case) also result in higher congestion-related wholesale market price differences between AEP load and generation and the

[16] As further discussed in the customer benefits analysis, which relies on the Company's AURORA-based fundamentals forecast, the SPP-Central zone in PROMOD closely matches the SPP-Central zone in AURORA.

SPP-Central region. Similar market price differences exist between SPP Central and the market prices faced by the Company's conventional generating units.

Table 5: PROMOD LMP Difference between SPP Central and AEP-West Load Zone

	Base Case		No-SPP-Upgrades Case		Bid Evaluation Case	
Simple Average LMP ($/MWh)	**2024**	**2029**	**2024**	**2029**	**2024**	**2029**
SPP Central	$28.94	$34.32	$28.06	$33.37	$25.80	$31.09
AEP West Load	$32.46	$38.75	$32.24	$38.90	$31.73	$38.15
AEP Load to SPP Central Differential	$3.52	$4.43	$4.17	$5.53	$5.93	$7.06

Q. WHAT ARE THE COMPANY'S CUSTOMER BENEFIT METRICS AND BENEFITS RESULTS?

A. The results of the Company's Customer Benefit Analysis are summarized in Company witness Torpey's testimony. As he shows, and as I summarize in my discussion of ERRATA Figure 3~~Figure 3~~ below, the benefits to SWEPCO customers of developing the Selected Wind Facilities are quite significant, with 31-year present values of SWEPCO customer benefits that exceed project costs by an amount ranging from approximately $~~200~~ 180 million to $395~~400~~ million under low gas or P95 low wind conditions, to approximately $540~~550~~ million to $720~~700~~ million under high gas price, or high-congestion conditions. As Company witness Torpey explains, benefits include lower power purchase costs (net of changes in off system sales), the avoided costs of deferring conventional generation capacity needs, and the Company's ability to take advantage of the federal production tax credit. Costs include the revenue requirement of the Selected Wind Facilities, and the congestion and loss costs associated with delivering the output from the facilities to the AEP load zone. Company witness Torpey's gen-tie (congestion risk mitigation) cases include the additional benefits of avoided (higher) congestion costs but with the added cost of the gen tie.

Q. ARE THESE CUSTOMER BENEFIT METRICS AND BENEFITS RESULTS REASONABLE?

A. Yes, they are.

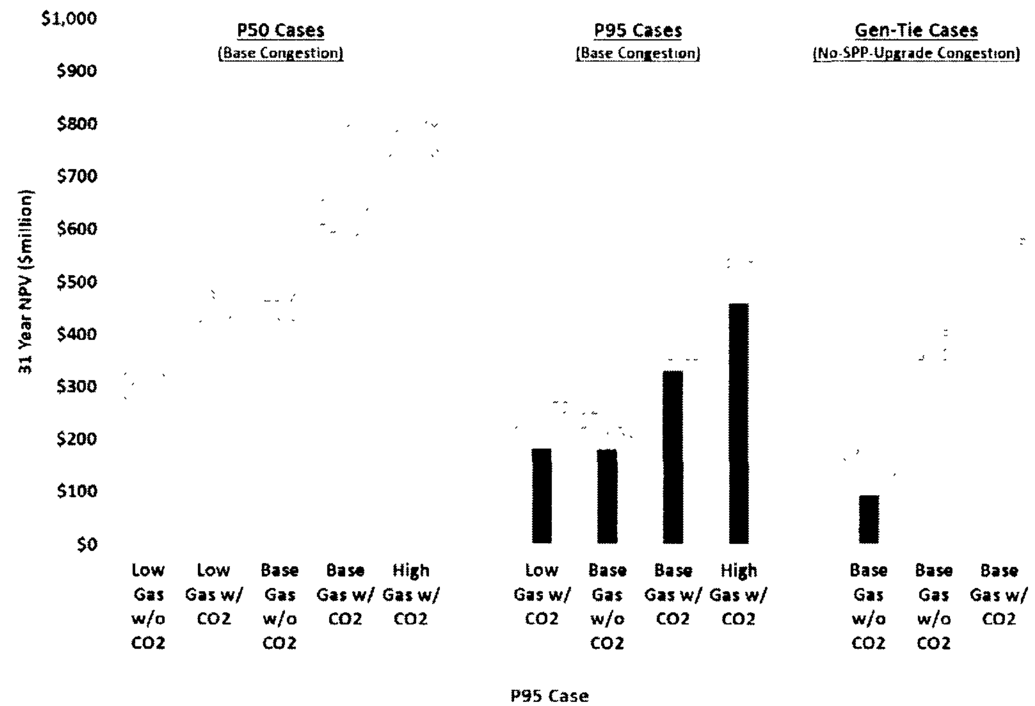
Q. DO YOU AGREE WITH THE BREAK-EVEN ANALYSIS PRESENTED BY THE COMPANY? PLEASE EXPLAIN.

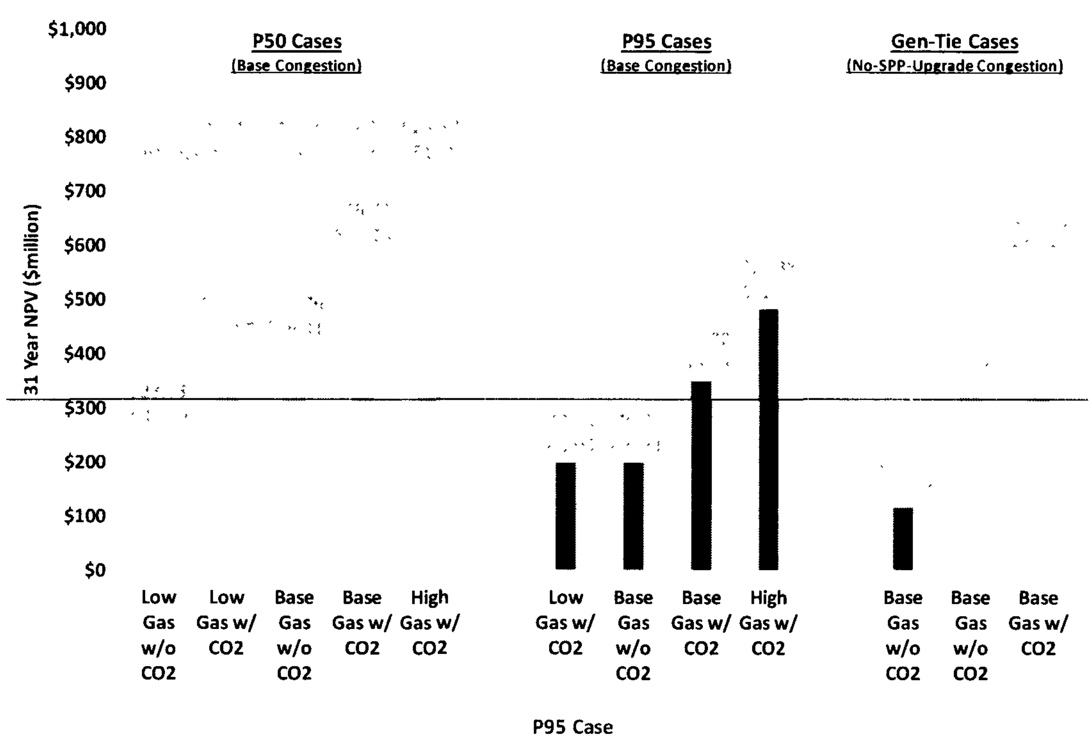
A. Yes, I do. The Company's break-even analysis undertaken by Company witness Torpey starts with the Company's *lowest* whole power price fundamentals forecast (based on the "low-gas/no-carbon" case) to calculate the net present value of customer benefits. The wholesale power prices for the AEP load zone are then decreased in every year until the net present value of customer benefits is zero, as discussed in Company witness Torpey's testimony. Company witness Bletzacker then calculates the break-even natural gas price based on Company witness Torpey's break-even wholesale power price and the SPP "market heat rate" for the low-gas/no-carbon case. This is a reasonable approach for estimating how low SPP wholesale power prices and natural gas prices would need to fall before the present value of benefits are exactly equal to the present value of costs, such that the net benefit is zero—which means the Selected Wind Facilities just break even with benefits covering costs.

Q. WHAT DO THE BREAK-EVEN ANALYSIS AND THE VARIOUS MARKET FUNDAMENTALS CASES INDICATE AS THEY APPLY TO CUSTOMER BENEFITS, COSTS, AND RISKS?

A. Company witness Torpey's break-even and customer benefit analyses show that the Selected Wind Facilities offer significant customer benefits and that these benefits are robust across a wide range of market fundamentals. The analyses also show that in futures in which higher congestion charges would otherwise diminish customer benefits, the ability to mitigate these congestion-related effects through transmission investments (such as a gen tie) safeguards these customer benefits. The results of the customer benefits analyses are summarized for SWEPCO in ERRATA Figure 3~~Figure 3~~ below, with each bar indicating the net present value of customer benefits for one of the 12 cases simulated. The lightly-shaded bars (sorted from lowest to highest customer benefits) represent P50 wind generation cases, while the dark bars represent the P95 low-wind generation cases. The dollar numbers above the bars indicate (for informational purposes) the 2021 and 2029 wholesale power price for the AEP load zone in each of these cases.

ERRATA Figure 3: Summary of SWEPCO Customer Benefit Results





The range of results for the various P50 cases in ERRATA Figure 3~~Figure 3~~ show that the Selected Wind Facilities have an attractive profile of benefits that essentially create a "hedge" against future gas price increases and possible carbon regulations. This hedge pays for itself by virtue of the Selected Wind Facilities' benefits that exceed costs even under the lowest projected market fundamentals. In a scenario of low overall customer costs, when wholesale power prices are low (e.g., \$30.79/MWh in 2029 for the low gas w/o CO_2 case), the net customer benefits of the Selected Wind Facilities are lower but still sizable (e.g., ~~just over~~ \$236~~250~~ million NPV), showing that the facilities more than pay for themselves through avoided fuel and capacity costs. However, in scenarios when overall customer costs are much higher due to higher wholesale power prices (e.g., \$51.39/MWh in 2029 for the high gas with CO_2 case), the net benefits of the Selected Wind Facilities are higher (e.g., \$718 ~~nearly \$750~~ million NPV), thus providing a valuable offset to the higher costs that would otherwise be faced by the Company's customers.

Q. PLEASE EXPLAIN THE IMPACT OF THE CONGESTION MITIGATION OPTION IN TERMS OF CUSTOMER BENEFITS, COSTS, AND RISKS.

A. The three bars on the right in ERRATA Figure 3~~Figure 3~~ show that in a future of higher congestion costs, the construction of a gen tie can be used to safeguard customer benefits. These gen-tie benefits are based on the "No-SPP-Upgrades" congestion results, which are somewhat higher than the Base Case congestion results as previously shown in Figure 1~~Figure 1~~. Nevertheless, despite the higher congestion costs, customer benefits remain. This means the avoided higher congestion cost would fully pay for the cost of constructing the gen tie under these market conditions. The higher the congestion costs, the more beneficial the gen-tie mitigation option will be.

VII. CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. My conclusions are as follows. First, the Company has reasonably relied on the SPP-developed PROMOD Reference Case. With the discussed modifications, it is reasonable to utilize this case for the congestion and loss analyses in both the Company's bid evaluation and customer benefits analysis of the wind facilities proposed and selected in response to the Company's RFP.

Second, there is significant but uncertain congestion in the SPP footprint, specifically affecting the cost of delivering generation from wind plants to load. This makes it important to evaluate the potential future exposure to such congestion cost and how these costs can be mitigated should they unexpectedly exceed the currently estimated levels.

Third, the Company's RFP bid-evaluation process employed in choosing the Selected Wind Facilities was reasonable. In reviewing the bid-evaluation process, I confirmed the reasonableness of the Company's assumptions, analyses, and criteria employed to choose the Selected Wind Facilities, considering the costs of the bids, the locations of the wind farms, exposure to future system congestion and deliverability limitations, and the feasibility of deploying potential congestion risk mitigation options in the event that high levels of congestion materialize in the future. I also found that the choice of Selected Wind Facilities is robust across a broad range of alternative selection criteria.

Fourth, the assumptions, analyses, and approach employed to determine the customer benefits of the Selected Wind Facilities are reasonable. The Company's Customer Benefits Analysis shows that the Selected Wind Facilities offer substantial net benefits under a broad range of market and wind conditions, including at low future energy prices and wind facility production levels. The break-even wholesale power prices are below recent historical price levels, while benefits increase significantly with higher future energy prices. These characteristics make developing the Selected Wind Facilities a hedge for SWEPCO customers that provides significant benefits under currently projected market conditions and that additionally mitigates the risks and costs associated with future power price increases, higher natural gas prices, possible future carbon regulations, and (through the gen-tie option) increased congestion in the SPP footprint.

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

A. MALCOLM SMOAK

FOR

SOUTHWESTERN ELECTRIC POWER COMPANY

JULY 2019

TESTIMONY INDEX

I. INTRODUCTION

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

A. My name is Albert Malcolm Smoak. I am employed by Southwestern Electric Power Company (SWEPCO or Company) as President and Chief Operating Officer (COO). SWEPCO is an operating company of American Electric Power Company, Inc., (AEP). My business address is 428 Travis Street, Shreveport, Louisiana 71101.

Q. WHAT ARE YOUR PRINCIPAL AREAS OF RESPONSIBILITY WITH SWEPCO?

A. As President and COO of SWEPCO, I am responsible for the safe delivery of reliable electric energy and quality services to our customers. This includes oversight of the following SWEPCO functions in Arkansas, Louisiana, and Texas:

- Distribution;
- Customer service;
- Regulatory and statutory compliance;
- Community and economic development; and
- Maintenance of SWEPCO's financial performance and health.

In addition, I provide strategic coordination of transmission and generation operations as these activities affect SWEPCO's financial health and day-to-day operations. In fulfilling these roles, I coordinate with American Electric Power Service Corporation (AEPSC) departments and leaders responsible for supporting SWEPCO's provision of utility services. I also represent SWEPCO as it interacts with other operating units within the AEP system.

Q. WILL YOU BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I hold a Bachelor of Science degree in electrical engineering from Louisiana Tech University and I am a registered professional engineer in the State of Louisiana. I am a member of the Institute of Electrical and Electronics Engineers (IEEE) and former President of the IEEE Shreveport chapter. I am a member of the National Society of Professional Engineers (NSPE) and I represent the NSPE on the National Electrical Safety Code, Subcommittee Eight.

My career at SWEPCO began in 1984 as a distribution engineer and I have held positions of escalating responsibility serving as a meterman supervisor, the Louisiana division operations superintendent, distribution operations supervisor, distribution engineering supervisor, and the Shreveport district manager of the distribution system. I assumed the position of Vice President of Distribution Region Operations in 2004 where I had responsibility for Distribution throughout the SWEPCO service territory in Arkansas, Louisiana and Texas. In May 2018, I was promoted to my current position.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSION?

A. Yes. I have filed testimony before the Arkansas Public Service Commission (APSC), the Louisiana Public Service Commission (LPSC or Commission), and the Public Utility Commission of Texas (PUCT). I have previously submitted testimony before this Commission in Docket Nos 46449, 45712, 40443, and 37364.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony: 1) discusses the need to acquire certain new wind facilities (collectively referred to as the Selected Wind Facilities, which are also referred to by the Company as the North Central Energy Facilities) for the benefit of customers; 2) sets out the time sensitive nature of the opportunity to capture the remaining benefits of the federal Production Tax Credits (PTCs) for SWEPCO's customers; 3) describes the opportunity to provide lower energy costs and savings to all SWEPCO customers of ~~$2.12~~ $2.03 billion on a nominal basis and ~~$588~~$567 million Net Present Value in the Base Fundamentals Forecast; 4) discusses the Company's guarantees for the benefit of customers; and 5) addresses the continued customer demand for renewable energy.

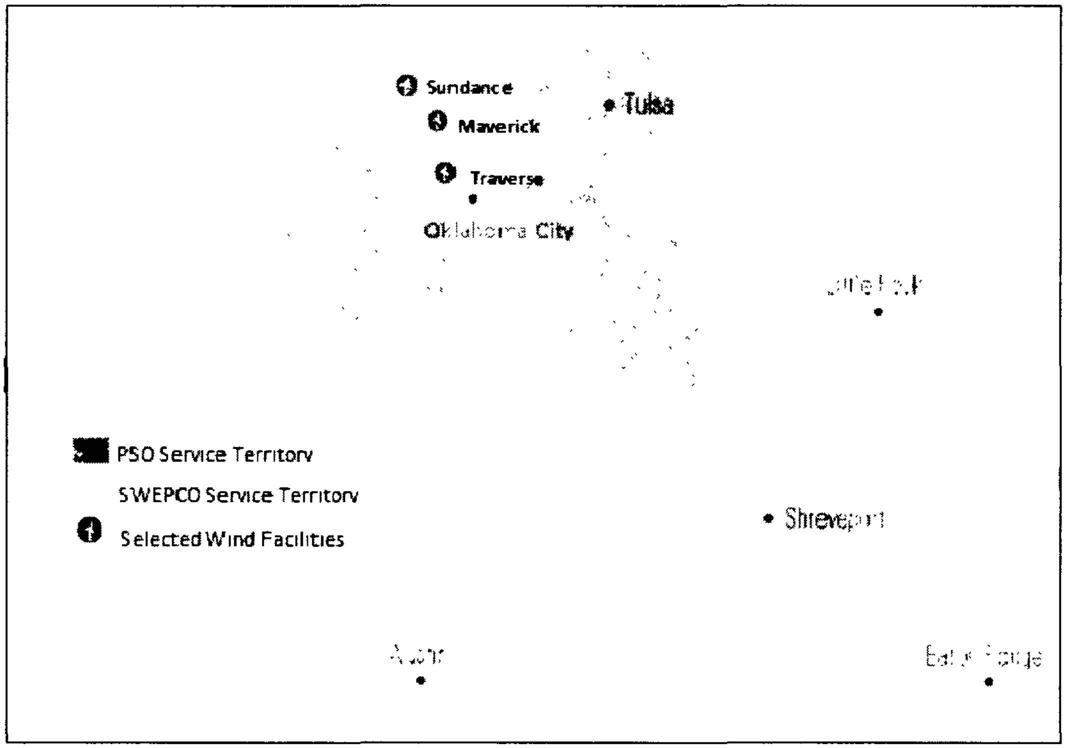
Q. PLEASE DESCRIBE THE SELECTED WIND FACILITIES TO BE ACQUIRED.

A. The Selected Wind Facilities were chosen through a market-competitive RFP process to evaluate and select the best bids for the benefit of customers, as further described by Company witnesses Brice and Godfrey. SWEPCO seeks approval to acquire 54.5% of the following Selected Wind Facilities:

Wind Facility Name	Total MW	SWEPCO Share
Traverse	999	544.5
Maverick	287	156
Sundance	199	108.5
Total	**1485**	**810**

SWEPCO's sister company, Public Service Company of Oklahoma (PSO), will acquire the remaining 45.5% share.

The Selected Wind Facilities are located in Oklahoma to access some of the best wind resources in the region, and are shown on the following map:



The developers of the Selected Wind Facilities will design, develop, construct, and commission the Facilities on a turn-key basis. No progress payments will be made by SWEPCO during that process and no cost recovery will begin until the Selected Wind Facilities are purchased and go into service. Company witness Aaron further describes the requested rate treatment, Company witness Godfrey further discusses the transactions with the sellers, and Company witness DeRuntz provides a more detailed description of the Selected Wind Facilities.

Q. PLEASE PROVIDE A BRIEF SUMMARY OF THE BACKGROUND OF THE NEED FOR THE SELECTED WIND FACILITIES.

A. In accordance with Arkansas and Louisiana regulatory requirements, SWEPCO prepares an Integrated Resource Plan (IRP) to guide its resource planning activities. That plan shows the need for significant increases in renewable energy, including wind and solar, while maintaining fuel diversity, over the next 20 years. PSO's IRP also shows a need for wind resources. Therefore, both SWEPCO and PSO issued Requests for Proposals (RFPs), which were then jointly evaluated resulting in the selection of the Selected Wind Facilities. The RFPs and the RFP evaluation process are discussed further by Company witness Godfrey. Concurrent with this application, SWEPCO is filing its requests for approval of the acquisitions with its jurisdictions in Louisiana and Texas, and with the Federal Electric Regulatory Commission (FERC). PSO has also filed a request with the Oklahoma Corporation Commission related to its acquisition of a share of the Selected Wind Facilities.

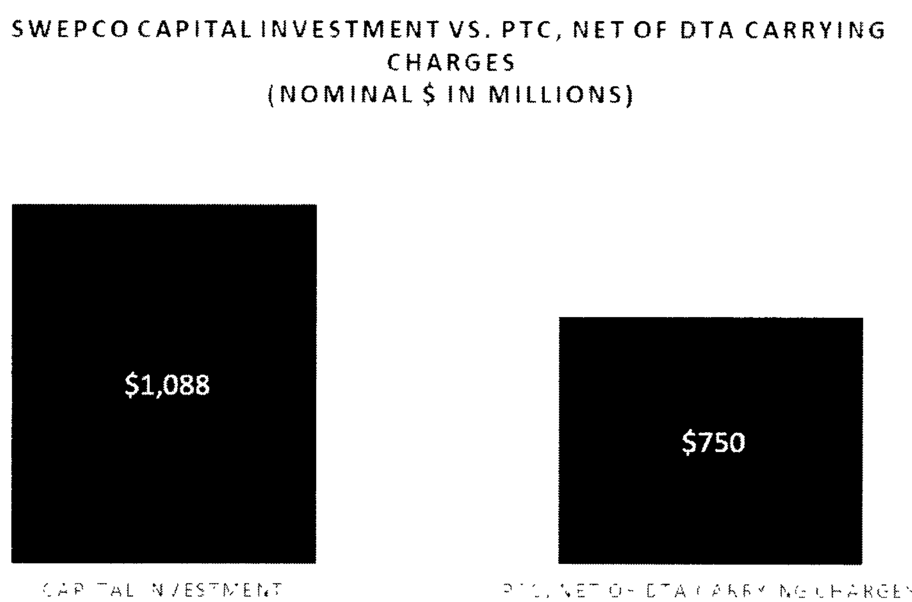
Acquisition of the Selected Wind Facilities is time sensitive to meet the requirements to receive at least 80% of the value of the federal Production Tax Credits (PTCs) for the Traverse and Maverick wind facilities and 100% PTC value for the Sundance wind facility. SWEPCO continues to see strong customer interest in more renewable energy to meet their sustainability and renewable energy goals.

Q. WILL THE SELECTED WIND FACILITIES BENEFIT CUSTOMERS WHILE SERVING CUSTOMERS' NEEDS?

A. Yes. Acquisition of the Selected Wind Facilities is expected to provide substantial benefits in excess of its costs for customers. As I discuss in more detail below, the acquisition will provide low-cost energy to customers and results in fuel savings because there are no fuel costs. It will also contribute to a more diversified generation mix of natural gas, wind, solar, and solid fuels, while meeting the demand for renewables.

Q. IS THE OPPORTUNITY TO CAPTURE SIGNIFICANT SAVINGS FOR SWEPCO'S CUSTOMERS TIME SENSITIVE?

A. Yes, definitely. The savings for SWEPCO's customers available pursuant to this Application are indeed significant, especially when compared to the capital costs of the Selected Wind Facilities. SWEPCO's capital outlay for the Selected Wind Facilities is $1.09 billion. Yet, SWEPCO's customers will receive the benefit of $750 million of PTCs net of deferred tax asset (DTA) carrying costs. But, the federal PTCs are being phased out over the next four years. As discussed in more detail by Company witness Multer there is limited time to assure the capture of these savings for SWEPCO's customers. This is shown in the figure below:



III. SUMMARY OF CUSTOMER BENEFITS

Q. WHAT ARE THE EXPECTED CUSTOMER BENEFITS OF THE SELECTED WIND FACILITIES?

A. The Selected Wind Facilities are expected to provide benefits in excess of costs that create savings of approximately ~~$2.12~~$2.03 billion on a total Company basis in nominal dollars and ~~$588~~$567 million Net Present Value over the life of the project in the Company's Base Fundamental Forecast. The Company's analysis shows robust savings and substantial customer benefits under a wide range of scenarios. The Selected Wind Facilities take advantage of federal PTCs for the benefit of customers to secure at least 80% of the value of the PTCs, and in the case of Sundance 100% of the value of the PTCs. Company witness Torpey discusses the specific SWEPCO customer benefits in his testimony.

Acquisition of the Selected Wind Facilities will result in lower costs to customers. With the rate treatment described by Company witness Aaron, the Selected Wind Facilities will reduce future fuel and energy cost escalation and provide more stable and predictable rates for our customers for 30 years. The Selected Wind Facilities will provide a significant volume of low-cost energy for customers while diversifying the generation mix and will reduce fuel costs going forward.

Q. HOW WERE THESE PROJECTED BENEFITS DETERMINED?

A. As further discussed in the testimonies of Company witnesses Bletzacker, Torpey, Sheilendranath, and Pfeifenberger, SWEPCO and PSO went through a robust modeling analysis to confirm that the Selected Wind Facilities will provide customer benefits when compared to the Base case.

Q. IN ADDITION TO NET CUSTOMER SAVINGS, WILL THE SELECTED WIND FACILITIES PROVIDE OTHER BENEFITS TO CUSTOMERS?

A. Yes. We constantly focus on economic development in the states and communities we serve. One of the ways we assist in economic development is by working to retain existing and attract new customers. Current and potential customers have expressed an increasing interest in energy savings including low-cost renewable energy to meet their sustainability goals. In fact, many local, regional, national, and international companies have sustainability goals, of which renewable energy is a key component. For example, some of the customers in the SWEPCO service territory that have publicly expressed a desire for increased renewable energy content include Walmart, Tyson Foods, McDonalds, Target, and United Parcel Service. The Selected Wind Facilities will meet customer demand for both sustainability and low-cost energy.

Q. WILL THE SELECTED WIND FACILITIES PROMOTE ECONOMIC GROWTH?

A. Yes. Growth can come in the form of expansion of existing companies and customers, as well as attracting new customers. Providing lower-cost energy and meeting sustainability goals helps achieve both of these objectives.

Q. DOES SWEPCO'S OWNERSHIP OF THE SELECTED WIND FACILITIES PROVIDE OTHER ADVANTAGES FOR CUSTOMERS?

A. Yes. As further addressed by Company witness Brice, acquisition of the Selected Wind Facilities provides significant benefits to SWEPCO customers, including reduced fuel costs and the potential value of the Facilities continuing to serve customers after they have been substantially depreciated. Finally, another benefit of SWEPCO and PSO purchasing and owning these Selected Wind Facilities is that the Company can better facilitate the guarantees discussed below.

IV. GUARANTEES FOR THE BENEFIT OF CUSTOMERS

Q. PLEASE DISCUSS THE GUARANTEES SWEPCO IS PROVIDING TO CUSTOMERS ASSOCIATED WITH THE ACQUISITION OF THE WIND FACILITIES.

A. SWEPCO is offering a suite of guarantees that are designed to protect customers and provide significant value. The guarantees include a cost cap, a long-term minimum production guarantee, and a guarantee that the Facilities will qualify for the PTC percentage at the levels outlined above. These guarantees are further detailed by Company witness Brice.

Q. ARE THE PERFORMANCE GUARANTEES A SUBSTANTIAL BENEFIT OF SWEPCO OWNING THE SELECTED WIND FACILITIES?

A. Yes. SWEPCO ownership and control of the Selected Wind Facilities facilitates the offering of these substantial guarantees for the benefit of customers. Ownership allows the Company to better respond to changing market conditions and to make operational decisions necessary to deliver the guarantees, as discussed further by Company witness Brice.

V. CONCLUSION

Q. PLEASE SUMMARIZE WHY THE COMMISSION SHOULD APPROVE SWEPCO'S ACQUISITION OF AN INTEREST IN THE SELECTED WIND FACILITIES.

A. The proposed transaction to acquire the Selected Wind Facilities is in the public interest and provides benefits in excess of its costs for SWEPCO customers and long-term fuel diversity for SWEPCO. The Selected Wind Facilities are estimated to result in savings to SWEPCO customers of ~~$2.12~~$2.03 billion in nominal dollars and of ~~$588~~$567 million on a Net Present Value basis in the Base Fundamentals Forecast. There are substantial customer benefits and savings over all the scenarios considered. There is no risk of fuel cost volatility and customers are seeking sustainable energy. However, due to the phase out of PTCs, there is a relatively limited period of time for SWEPCO to take full advantage of the potential acquisition of the wind resources for the benefit of customers.

Accordingly, SWEPCO respectfully requests approval of the transaction to acquire the Selected Wind Facilities.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes. Thank you.

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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
ERRATA EXHIBIT JFT-3	Benefits of Selected Wind Facilities
ERRATA 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~~ 567 million on a net present value (NPV) basis, or ~~$2,120~~ $2,030 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~~ 396 million on an NPV basis or ~~$1,540~~$1,453 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 Errata Table 1.

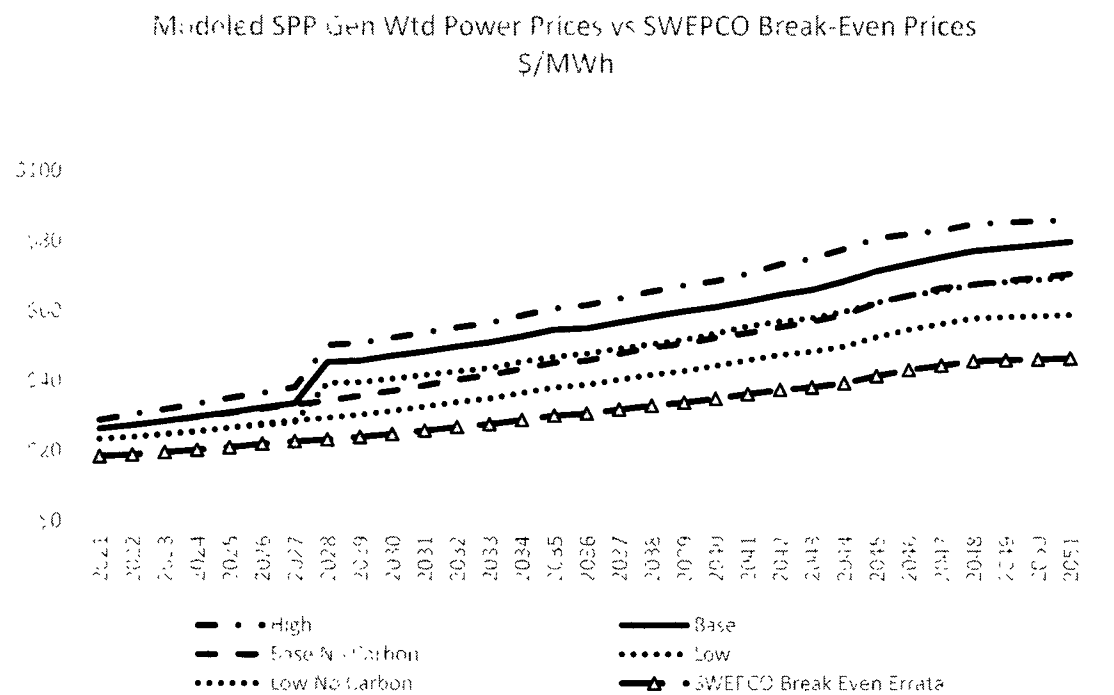
Errata Table 1: Benefits of Selected Wind Facilities – All Fundamental Forecasts and P50 Capacity Factor

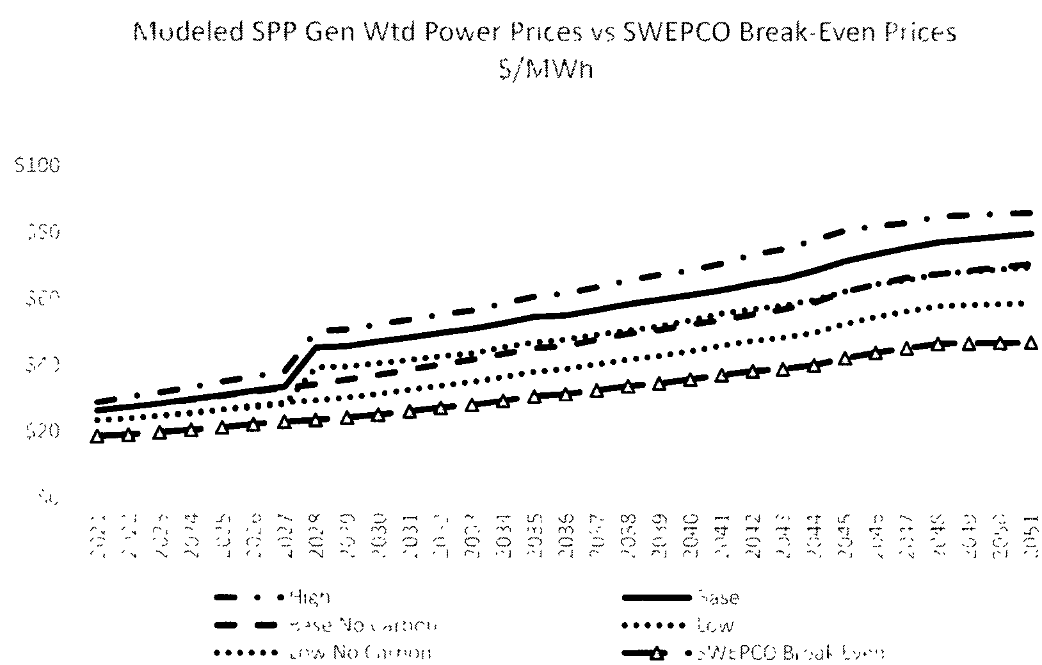
SWEPCO			
Amounts in Millions	31 Year NPV	PTC Period - First 11 years Nominal Total	Full 31 Year Nominal Total
P50 Capacity Factor Cases			
High Gas With CO2	$718	$520	$2,501
Base Gas With CO2	$567	$418	$2,030
Base Gas Without CO2	$396	$318	$1,453
Low Gas With CO2	$396	$296	$1,532
Low Gas Without CO2	$236	$211	$971

~~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 Errata 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 Errata Figure 1 is well below all of the Company's forecasted power prices.

Errata **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
- ERRATA JFT-3 Benefits of Selected Wind Facilities
- ERRATA 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	[illegible]																	[illegible]	[illegible]
	[illegible]					[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	[illegible]	15	21	20	[illegible]	23	20	[illegible]	[illegible]	[illegible]		10		[illegible]		[illegible]	[illegible]	[illegible]	1
	[illegible]	21	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	37	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	43	[illegible]	[illegible]	[illegible]	43
	[illegible]	4	[illegible]	[illegible]	[illegible]	4	[illegible]	[illegible]		[illegible]	[illegible]	[illegible]	[illegible]		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
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. Errata 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. ERRATA EXHIBIT JFT-3, pages 1-2, shows the annual costs and benefits of this case.

ERRATA 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	$1,660	$5,095
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	**$567**	**$2,030**

~~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**~~

Errata Base Gas with No Carbon and P50 Capacity Factor

Year	31 Year NPV	Total 31 Year Nominal
Production Cost Savings Excluding Congestion/Losses	$1,448	$4,386
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	**$396**	**$1,453**

~~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 ERRATA 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 Errata 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 Errata 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. Errata 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 Errata 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~~33% 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.

ERRATA 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 Errata Table 1 and are summarized in ERRATA 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 ERRATA 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 ERRATA 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 Errata 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 Errata 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~~33% 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-2a2e3e8a2688&Class=Filing

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NORTH CENTRAL WIND ENERGY FACILITIES - SWEPCO 810 MW SHARE OF ALL THREE PROJECTS
P50 BASE GAS WITH CARBON CUSTOMER COSTS AND BENEFITS VS BASELINE - 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	$1,660	$5,095	$12	$86	$89	$93	$97	$101	$105	$143	$143	$147	$151
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)	**$567**	**$2,030**	**$6**	**$20**	**$22**	**$21**	**$26**	**$25**	**$29**	**$66**	**$67**	**$72**	**$63**

Year	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
1 Production Cost Savings Excluding Congestion/Losses	$156	$159	$164	$170	$172	$177	$171	$175	$190	$186	$193	$204	$212
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)	**($13)**	**$2**	**$17**	**$29**	**$33**	**$41**	**$90**	**$97**	**$57**	**$112**	**$119**	**$75**	**$86**

Year	2045	2046	2047	2048	2049	2050	2051
1 Production Cost Savings Excluding Congestion/Losses	$220	$225	$227	$233	$239	$242	$211
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)	**$97**	**$104**	**$157**	**$161**	**$119**	**$122**	**$108**

NORTH CENTRAL WIND ENERGY FACILITIES - SWEPCO 810 MW SHARE OF ALL THREE PROJECTS
P50 BASE GAS NO CARBON CUSTOMER COSTS AND BENEFITS VS BASELINE - 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	$1,448	$4,386	$12	$86	$89	$93	$97	$100	$104	$108	$111	$115	$119
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)	**$396**	**$1,453**	**$6**	**$20**	**$22**	**$21**	**$26**	**$27**	**$32**	**$36**	**$42**	**$47**	**$38**

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	$148	$146	$161	$157	$163	$175	$181
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)**	**($22)**	**($9)**	**$2**	**$6**	**$16**	**$66**	**$74**	**$35**	**$88**	**$93**	**$54**	**$65**

Year	2045	2046	2047	2048	2049	2050	2051
1 Production Cost Savings Excluding Congestion/Losses	$191	$197	$193	$199	$210	$212	$185
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)	**$78**	**$84**	**$127**	**$131**	**$97**	**$99**	**$88**

NORTH CENTRAL WIND ENERGY FACILITIES - SWEPCO 810 MW SHARE OF ALL THREE PROJECTS
P50 LOW GAS WITH CARBON CUSTOMER COSTS AND BENEFITS VS BASELINE - 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	$1,452	$4,476	$10	$75	$77	$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)	**$396**	**$1,532**	**$6**	**$12**	**$13**	**$11**	**$15**	**$14**	**$17**	**$51**	**$53**	**$57**	**$47**

Year	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
1 Production Cost Savings Excluding Congestion/Losses	$134	$137	$148	$153	$156	$160	$156	$154	$167	$164	$169	$179	$185
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)	**($30)**	**($16)**	**($3)**	**$8**	**$13**	**$21**	**$72**	**$80**	**$38**	**$95**	**$101**	**$53**	**$62**

Year	2045	2046	2047	2048	2049	2050	2051
1 Production Cost Savings Excluding Congestion/Losses	$193	$198	$198	$204	$209	$213	$188
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)	**$72**	**$78**	**$141**	**$147**	**$106**	**$109**	**$90**

NORTH CENTRAL WIND ENERGY FACILITIES - SWEPCO 810 MW SHARE OF ALL THREE PROJECTS
P50 HIGH GAS WITH CARBON CUSTOMER COSTS AND BENEFITS VS BASELINE - 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	$1,849	$5,676	$13	$95	$99	$104	$110	$114	$118	$157	$158	$163	$167
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)	**$718**	**$2,501**	**$7**	**$28**	**$30**	**$30**	**$35**	**$35**	**$40**	**$76**	**$78**	**$84**	**$76**

Year	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
1 Production Cost Savings Excluding Congestion/Losses	$172	$176	$182	$189	$192	$198	$191	$196	$212	$209	$217	$231	$240
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**	**$49**	**$59**	**$103**	**$111**	**$78**	**$127**	**$133**	**$102**	**$118**

Year	2045	2046	2047	2048	2049	2050	2051
1 Production Cost Savings Excluding Congestion/Losses	$249	$252	$252	$260	$264	$265	$230
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)	**$130**	**$132**	**$167**	**$173**	**$142**	**$143**	**$125**

NORTH CENTRAL WIND ENERGY FACILITIES - SWEPCO 810 MW SHARE OF ALL THREE PROJECTS
P50 LOW GAS NO CARBON CUSTOMER COSTS AND BENEFITS VS BASELINE - 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	$1,277	$3,988	$10	$75	$78	$81	$84	$88	$90	$93	$95	$98	$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)	**$236**	**$971**	**$6**	**$12**	**$14**	**$11**	**$16**	**$18**	**$22**	**$24**	**$29**	**$34**	**$25**

Year	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
1 Production Cost Savings Excluding Congestion/Losses	$106	$113	$118	$123	$126	$130	$127	$125	$137	$134	$138	$149	$154
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)**	**($16)**	**($11)**	**($3)**	**$49**	**$57**	**$14**	**$71**	**$77**	**$29**	**$37**

Year	2045	2046	2047	2048	2049	2050	2051
1 Production Cost Savings Excluding Congestion/Losses	$161	$167	$212	$218	$224	$227	$206
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)	**$47**	**$54**	**$115**	**$122**	**$82**	**$84**	**$70**

Benefits of Selected Wind Facilities (Low No Carbon P50)

Benefits of Selected Wind Facilities (Base P95)

NORTH CENTRAL WIND ENERGY FACILITIES - SWEPCO 810 MW SHARE OF ALL THREE PROJECTS
P95 BASE GAS WITH CARBON CUSTOMER COSTS AND BENEFITS VS BASELINE - 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	$1,437	$4,410	$10	$74	$77	$81	$84	$88	$91	$124	$124	$128	$131
2 Congestion and Losses	($279)	($774)	($3)	($16)	($17)	($17)	($19)	($21)	($23)	($26)	($28)	($28)	($28)
3 Capacity Value	$70	$311	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4 Production Tax Credits, Grossed Up	$546	$834	$13	$76	$79	$79	$82	$82	$85	$85	$88	$88	$75
5 Deferred Tax Asset Carrying Charges	($96)	($163)	($0 4)	($3 2)	($7 7)	($11 5)	($14 2)	($16 1)	($17 4)	($18 2)	($18 7)	($18 9)	($18 2)
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)	**$330**	**$1,386**	**$4**	**($0)**	**$2**	**$1**	**$5**	**$6**	**$9**	**$41**	**$43**	**$48**	**$42**

Year	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
1 Production Cost Savings Excluding Congestion/Losses	$135	$138	$142	$148	$149	$153	$147	$150	$165	$161	$166	$177	$184
2 Congestion and Losses	($28)	($28)	($28)	($28)	($28)	($28)	($28)	($28)	($28)	($28)	($28)	($28)	($28)
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	($13)	($5)	$0	$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)	**($23)**	**($8)**	**$3**	**$10**	**$14**	**$21**	**$70**	**$76**	**$36**	**$91**	**$97**	**$52**	**$62**

Year	2045	2046	2047	2048	2049	2050	2051
1 Production Cost Savings Excluding Congestion/Losses	$191	$195	$196	$202	$208	$210	$182
2 Congestion and Losses	($28)	($28)	($28)	($28)	($28)	($28)	($23)
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)	**$72**	**$78**	**$131**	**$134**	**$92**	**$94**	**$83**

NORTH CENTRAL WIND ENERGY FACILITIES - SWEPCO 810 MW SHARE OF ALL THREE PROJECTS
P95 BASE GAS NO CARBON CUSTOMER COSTS AND BENEFITS VS BASELINE - 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	$1,255	$3,798	$10	$74	$77	$80	$84	$87	$90	$93	$96	$100	$104
2 Congestion and Losses	($233)	($628)	($3)	($16)	($17)	($17)	($18)	($19)	($20)	($21)	($22)	($22)	($22)
3 Capacity Value	$57	$274	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4 Production Tax Credits Grossed Up	$546	$834	$13	$76	$79	$79	$82	$82	$85	$85	$88	$88	$75
5 Deferred Tax Asset Carrying Charges	($96)	($163)	($0 4)	($3 2)	($7 7)	($11 5)	($14 2)	($16 1)	($17 4)	($18 2)	($18 7)	($18 9)	($18 2)
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)	**$181**	**$883**	**$4**	**($0)**	**$2**	**$1**	**$6**	**$7**	**$12**	**$15**	**$21**	**$26**	**$20**

Year	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
1 Production Cost Savings Excluding Congestion/Losses	$108	$112	$121	$126	$128	$133	$128	$126	$139	$135	$140	$152	$157
2 Congestion and Losses	($22)	($22)	($22)	($22)	($22)	($22)	($22)	($22)	($22)	($22)	($22)	($22)	($22)
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	($13)	($5)	$0	$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)	**($44)**	**($29)**	**($20)**	**($13)**	**($9)**	**($1)**	**$49**	**$57**	**$17**	**$69**	**$74**	**$34**	**$44**

Year	2045	2046	2047	2048	2049	2050	2051
1 Production Cost Savings Excluding Congestion/Losses	$166	$170	$166	$171	$182	$184	$160
2 Congestion and Losses	($22)	($22)	($22)	($22)	($22)	($22)	($18)
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)	**$56**	**$61**	**$103**	**$107**	**$72**	**$74**	**$65**

Benefits of Selected Wind Facilities (Base No Carbon P95)

NORTH CENTRAL WIND ENERGY FACILITIES - SWEPCO 810 MW SHARE OF ALL THREE PROJECTS
P95 LOW GAS WITH CARBON CUSTOMER COSTS AND BENEFITS VS BASELINE - 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	$1,259	$3,878	$9	$65	$67	$69	$72	$75	$77	$108	$108	$111	$113
2 Congestion and Losses	($241)	($671)	($2)	($14)	($14)	($15)	($17)	($18)	($20)	($22)	($24)	($24)	($24)
3 Capacity Value	$63	$313	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4 Production Tax Credits, Grossed Up	$546	$834	$13	$76	$79	$79	$82	$82	$85	$85	$88	$88	$75
5 Deferred Tax Asset Carrying Charges	($96)	($163)	($0 4)	($3 2)	($7 7)	($11 5)	($14 2)	($16 1)	($17 4)	($18 2)	($18 7)	($18 9)	($18 2)
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)	**$183**	**$960**	**$3**	**($7)**	**($6)**	**($8)**	**($4)**	**($4)**	**($1)**	**$29**	**$31**	**$35**	**$28**

Year	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
1 Production Cost Savings Excluding Congestion/Losses	$117	$119	$129	$133	$136	$140	$135	$132	$145	$141	$146	$156	$160
2 Congestion and Losses	($24)	($24)	($24)	($24)	($24)	($24)	($24)	($24)	($24)	($24)	($24)	($24)	($24)
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	($13)	($5)	$0	$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)**	**($24)**	**($14)**	**($8)**	**($3)**	**$4**	**$55**	**$62**	**$20**	**$76**	**$81**	**$33**	**$41**

Year	2045	2046	2047	2048	2049	2050	2051
1 Production Cost Savings Excluding Congestion/Losses	$167	$171	$171	$176	$182	$185	$163
2 Congestion and Losses	($24)	($24)	($24)	($24)	($24)	($24)	($20)
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)	**$50**	**$55**	**$118**	**$123**	**$81**	**$85**	**$69**

NORTH CENTRAL WIND ENERGY FACILITIES - SWEPCO 810 MW SHARE OF ALL THREE PROJECTS
P95 HIGH GAS WITH CARBON CUSTOMER COSTS AND BENEFITS VS BASELINE - 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	$1,601	$4,913	$11	$83	$86	$91	$95	$99	$103	$136	$137	$141	$145
2 Congestion and Losses	($310)	($861)	($3)	($18)	($19)	($19)	($22)	($24)	($26)	($28)	($31)	($31)	($31)
3 Capacity Value	$68	$301	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4 Production Tax Credits Grossed Up	$546	$834	$13	$76	$79	$79	$82	$82	$85	$85	$88	$88	$75
5 Deferred Tax Asset Carrying Charges	($96)	($163)	($0.4)	($3.2)	($7.7)	($11.5)	($14.2)	($16.1)	($17.4)	($18.2)	($18.7)	($18.9)	($18.2)
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)	**$461**	**$1,792**	**$4**	**$6**	**$9**	**$9**	**$14**	**$14**	**$18**	**$51**	**$53**	**$59**	**$52**

Year	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
1 Production Cost Savings Excluding Congestion/Losses	$149	$152	$158	$164	$167	$171	$164	$168	$184	$180	$186	$200	$208
2 Congestion and Losses	($31)	($31)	($31)	($31)	($31)	($31)	($31)	($31)	($31)	($31)	($31)	($31)	($31)
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	($13)	($5)	$0	$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)	**($11)**	**$3**	**$15**	**$23**	**$28**	**$37**	**$80**	**$88**	**$55**	**$102**	**$107**	**$76**	**$90**

Year	2045	2046	2047	2048	2049	2050	2051
1 Production Cost Savings Excluding Congestion/Losses	$216	$218	$218	$225	$229	$230	$199
2 Congestion and Losses	($31)	($31)	($31)	($31)	($31)	($31)	($26)
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)	**$101**	**$103**	**$138**	**$143**	**$111**	**$113**	**$98**

NORTH CENTRAL WIND ENERGY FACILITIES - SWEPCO 810 MW SHARE OF ALL THREE PROJECTS
NETWORK UPGRADES ONLY BRATTLE HIGHER CONGESTION CASE
P50 BASE GAS WITH CARBON CUSTOMER COSTS AND BENEFITS VS BASELINE - TIE LINE IN SERVICE 2026
$ 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	$1,658	$5,057	$12	$88	$92	$96	$100	$104	$104	$143	$143	$147	$150
2 Congestion and Losses	($113)	($149)	($3)	($26)	($27)	($28)	($31)	($34)	$0	$0	$0	$0	$0
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)	($3 6)	($8 9)	($13 4)	($16 7)	($19 1)	($21 1)	($22 4)	($23 3)	($24 1)	($24 3)
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	($233)	($712)	$0	$0	$0	$0	$0	$0	($36)	($35)	($35)	($34)	($34)
8. Total Net Customer Benefits/(Cost)	**$541**	**$2,025**	**$6**	**$15**	**$17**	**$16**	**$20**	**$19**	**$20**	**$59**	**$64**	**$69**	**$61**

Year	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
1 Production Cost Savings Excluding Congestion/Losses	$155	$159	$164	$170	$172	$177	$167	$171	$189	$182	$188	$202	$210
2 Congestion and Losses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
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	($33)	($32)	($31)	($30)	($30)	($29)	($28)	($27)	($26)	($26)	($26)	($25)	($25)
8. Total Net Customer Benefits/(Cost)	**($15)**	**$1**	**$17**	**$30**	**$35**	**$43**	**$89**	**$97**	**$61**	**$113**	**$120**	**$80**	**$91**

Year	2045	2046	2047	2048	2049	2050	2051
1 Production Cost Savings Excluding Congestion/Losses	$218	$223	$221	$227	$237	$240	$209
2 Congestion and Losses	$0	$0	$0	$0	$0	$0	$0
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	($25)	($25)	($24)	($24)	($24)	($24)	($24)
8. Total Net Customer Benefits/(Cost)	**$102**	**$109**	**$159**	**$163**	**$125**	**$128**	**$109**

NORTH CENTRAL WIND ENERGY FACILITIES - SWEPCO 810 MW SHARE OF ALL THREE PROJECTS
NETWORK UPGRADES ONLY BRATTLE HIGHER CONGESTION CASE
P50 BASE GAS NO CARBON CUSTOMER COSTS AND BENEFITS VS BASELINE - TIE LINE IN SERVICE 2026
$ 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	$1,404	$4,254	$12	$88	$92	$96	$99	$103	$103	$107	$97	$101	$105
2 Congestion and Losses	($109)	($143)	($3)	($26)	($27)	($28)	($29)	($30)	$0	$0	$0	$0	$0
3 Capacity Value	$108	$368	$0	$0	$0	$0	$0	$0	$0	$0	$20	$20	$20
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)	($3 6)	($8 9)	($13 4)	($16 7)	($19 1)	($21 1)	($22 4)	($23 3)	($24 1)	($24 3)
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	($233)	($712)	$0	$0	$0	$0	$0	$0	($36)	($35)	($35)	($34)	($34)
8 Total Net Customer Benefits/(Cost)	**$330**	**$1,285**	**$6**	**$15**	**$17**	**$16**	**$21**	**$22**	**$19**	**$24**	**$38**	**$44**	**$36**

Year	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
1 Production Cost Savings Excluding Congestion/Losses	$109	$113	$133	$138	$140	$146	$139	$143	$159	$153	$159	$173	$179
2 Congestion and Losses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3 Capacity Value	$21	$21	($2)	($2)	($2)	($1)	$52	$53	($4)	$53	$51	($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	($33)	($32)	($31)	($30)	($30)	($29)	($28)	($27)	($26)	($26)	($26)	($25)	($25)
8. Total Net Customer Benefits/(Cost)	**($40)**	**($24)**	**($16)**	**($4)**	**$1**	**$11**	**$60**	**$67**	**$29**	**$81**	**$87**	**$49**	**$59**

Year	2045	2046	2047	2048	2049	2050	2051
1 Production Cost Savings Excluding Congestion/Losses	$189	$195	$188	$194	$208	$210	$184
2 Congestion and Losses	$0	$0	$0	$0	$0	$0	$0
3 Capacity Value	($4)	($2)	$45	$42	($5)	($4)	$3
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	($25)	($25)	($24)	($24)	($24)	($24)	($24)
8. Total Net Customer Benefits/(Cost)	**$69**	**$78**	**$121**	**$126**	**$94**	**$97**	**$82**

NORTH CENTRAL WIND ENERGY FACILITIES - SWEPCO 810 MW SHARE OF ALL THREE PROJECTS
NETWORK UPGRADES ONLY BRATTLE HIGHER CONGESTION CASE
P95 BASE GAS NO CARBON CUSTOMER COSTS AND BENEFITS VS BASELINE - TIE LINE IN SERVICE 2026
$ 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	$1,211	$3,668	$10	$76	$79	$83	$86	$89	$90	$93	$82	$86	$89
2 Congestion and Losses	($94)	($124)	($3)	($22)	($23)	($24)	($25)	($26)	$0	$0	$0	$0	$0
3 Capacity Value	$108	$368	$0	$0	$0	$0	$0	$0	$0	$0	$20	$20	$20
4 Production Tax Credits Grossed Up	$546	$834	$13	$76	$79	$79	$82	$82	$85	$85	$88	$88	$75
5 Deferred Tax Asset Carrying Charges	($96)	($163)	($0 4)	($3 2)	($7 7)	($11 5)	($14 2)	($16 1)	($17 4)	($18 2)	($18 7)	($18 9)	($18 2)
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	($233)	($712)	$0	$0	$0	$0	$0	$0	($36)	($35)	($35)	($34)	($34)
8. Total Net Customer Benefits/(Cost)	**$94**	**$640**	**$4**	**($4)**	**($2)**	**($4)**	**$1**	**$3**	**($4)**	**$1**	**$15**	**$20**	**$14**

Year	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
1 Production Cost Savings Excluding Congestion/Losses	$93	$96	$115	$120	$122	$126	$119	$122	$138	$131	$136	$150	$155
2 Congestion and Losses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3 Capacity Value	$21	$21	($2)	($2)	($2)	($1)	$52	$53	($4)	$53	$51	($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	($13)	($5)	$0	$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	($33)	($32)	($31)	($30)	($30)	($29)	($28)	($27)	($26)	($26)	($26)	($25)	($25)
8. Total Net Customer Benefits/(Cost)	**($49)**	**($34)**	**($30)**	**($22)**	**($17)**	**($9)**	**$39**	**$46**	**$8**	**$60**	**$64**	**$26**	**$35**

Year	2045	2046	2047	2048	2049	2050	2051
1 Production Cost Savings Excluding Congestion/Losses	$164	$169	$161	$166	$180	$182	$158
2 Congestion and Losses	$0	$0	$0	$0	$0	$0	$0
3 Capacity Value	($4)	($2)	$45	$42	($5)	($4)	$3
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	($25)	($25)	($24)	($24)	($24)	($24)	($24)
8 Total Net Customer Benefits/(Cost)	**$44**	**$53**	**$94**	**$98**	**$66**	**$69**	**$57**

Natural Gas Price and Other Sensitivities

SWEPCO

Line	Amounts in Millions	31 Year NPV	PTC Period - First 11 years Nominal Total	Full 31 Year Nominal Total
	P50 Capacity Factor Cases			
1	High Gas With CO2	$718	$520	$2,501
2	Base Gas With CO2	$567	$418	$2,030
3	Base Gas Without CO2	$396	$318	$1,453
4	Low Gas With CO2	$396	$296	$1,532
5	Low Gas Without CO2	$236	$211	$971

Line	Amounts in Millions	31 Year NPV	PTC Period - First 11 years Nominal Total	Full 31 Year Nominal Total
	P95 Capacity Factor Cases			
1	High Gas With CO2	$461	$290	$1,792
2	Base Gas With CO2	$330	$202	$1,386
3	Base Gas Without CO2	$181	$115	$883
4	Low Gas With CO2	$183	$95	$960

	Higher Congestion With Tie Line In Service 2026			
Line	Amounts in Millions	31 Year NPV	PTC Period - First 11 years Nominal Total	Full 31 Year Nominal Total
	P50 Capacity Factor Cases			
1	Base Gas With CO2	$541	$367	$2,025
2	Base Gas Without CO2	$330	$258	$1,285
	P95 Capacity Factor Case			
3	Base Gas Without CO2	$94	$43	$640

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 O. AARON

FOR

SOUTHWESTERN ELECTRIC POWER COMPANY

JULY 15, 2019

TESTIMONY INDEX

SECTION PAGE

EXHIBITS

EXHIBIT	DESCRIPTION
ERRATA EXHIBIT JOA-1	Summary of Customer Benefits
ERRATA EXHIBIT JOA-2	Impact on Major Rate Classes

I. INTRODUCTION

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

A. My name is John O. Aaron. I am Director, Regulated Pricing and Analysis in the Regulatory Services Department of American Electric Power Service Corporation (AEPSC). AEPSC is a subsidiary of American Electric Power Company, Inc. (AEP) that provides corporate support services to the operating subsidiaries of AEP, including Southwestern Electric Power Company (SWEPCO or Company). My business address is 212 East Sixth Street, Tulsa, Oklahoma 74119-1295.

Q. PLEASE BRIEFLY DESCRIBE YOUR CURRENT JOB RESPONSIBILITIES.

A. As Director, Regulated Pricing and Analysis, I supervise the preparation of cost-of-service studies, rate design, special contracts and pricing, and tariff provisions for the three AEP West operating companies[1] that operate in the Southwest Power Pool (SPP) and the Electric Reliability Council of Texas (ERCOT). I am also responsible for the preparation of, and support for, filings before the regulatory commissions exercising jurisdiction over the electric operating companies of the western portion of AEP, including SWEPCO.

Q. WOULD YOU PLEASE REVIEW YOUR EDUCATIONAL AND BUSINESS BACKGROUND?

A. I received a Bachelor of Science in Accounting from Louisiana State University in Shreveport in May 1980. I am a Certified Public Accountant (CPA) in the State of Oklahoma and a member of the American Institute of CPAs and the Oklahoma Society

[1] The AEP West operating companies include Southwestern Electric Power Company, Public Service Company of Oklahoma, and AEP Texas Inc.

of CPAs. Upon graduation from college, I was employed as an Internal Auditor for a multi-state wholesale appliance and electrical supplier in Shreveport, Louisiana. In May 1984, I accepted employment with SWEPCO as an accountant in the Property Accounting Department. From 1985 through 1995, I held various positions in the Accounting, Internal Auditing, and Rate Departments, including Supervisor of Regulatory Accounting Support and Supervisor of Wholesale Marketing Support. From 1995 through 2010, I held various accounting positions in the Regulatory Accounting Services Department at Central and South West Services, Inc. (CSWS), the service company for the former Central and South West Corporation (CSW) System. With the merger of AEP and CSW, as of January 1, 2001, AEPSC became the successor to CSWS. In August 2010, I transferred to AEPSC's Regulatory Services Department as manager and was promoted in April 2019 to my current position as Director, Regulated Pricing and Analysis.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY BEFORE THIS COMMISSION OR OTHER COMMISSIONS?

A. Yes. Before the Public Utility Commission of Texas (PUC or Commission), I have filed testimony in the following: SWEPCO Docket Nos. 32624, 32672, 32898, 35137, 36949, 37364, 40443, 42089, 42448, 44496, 46449, 47461, and 49042; AEP Texas North Company Docket Nos. 18607, 18970, 21385, and 23477; AEP Texas Central Company Docket No. 22352; and AEP Texas Docket No. 49494. I have also filed testimony before the Arkansas Public Service Commission, the Louisiana Public Service Commission, and the Oklahoma Corporation Commission.

II. PURPOSE OF TESTIMONY

Q. PLEASE DESCRIBE THE PURPOSE OF YOUR TESTIMONY.

A. I quantify the estimated impact on SWEPCO's costs and rates of SWEPCO's and Public Service Company of Oklahoma's (PSO's) proposal to purchase three wind generating facilities in Oklahoma (Selected Wind Facilities). SWEPCO has contracted to purchase 54.5% of the Facilities and PSO will purchase the remaining 45.5%. My rate impact compares SWEPCO's proposed base rate and fuel revenues in Texas to the base rate and fuel revenues with the Selected Wind Facilities' estimated revenue requirement and fuel cost savings. Acquisition of the Selected Wind Facilities is expected to result in savings that will more than offset SWEPCO's fixed cost revenue requirement, resulting in a net decrease in customer costs over the life of the project.

Q. WHAT EXHIBITS ARE YOU SPONSORING?

A. I sponsor the following Errata exhibits attached to my testimony.

ERRATA EXHIBIT JOA-1: Summary of Customer Benefits.

ERRATA EXHIBIT JOA-2: Impact on Major Rate Classes.

III. IMPACT ON TEXAS CUSTOMERS

Q. HOW ARE THE CUSTOMER IMPACTS DETERMINED?

A. The impact of the Selected Wind Facilities on SWEPCO's costs and rates reflects the annual revenue requirement associated with the Facilities, the estimated cost savings due to the addition of the Facilities to SWEPCO's existing generation, and the offset resulting from federal Production Tax Credits (PTCs). These cost elements, when combined with SWEPCO's current revenues, provide sufficient information for estimating the cost and rate impact to the Texas jurisdiction. This is similar to the standard cost-of-service formula that is applied during a rate case proceeding. ERRATA EXHIBIT JOA-1, a summary of the expected net customer benefits, provides SWEPCO's Texas retail allocation of the revenue requirement, the cost savings for the Facilities, and the credit for the PTCs earned. As shown on this Errata exhibit, it is expected that the Facilities' savings and PTCs will more than offset its fixed cost revenue requirement, resulting in a net decrease in customer costs over the life of the project.

Q. HOW WAS THE REVENUE REQUIREMENT DETERMINED?

A. The Selected Wind Facilities' revenue requirement recovers the return and taxes on the Facilities' assets, a return on a Deferred Tax Asset (DTA), depreciation expense, and the associated operations and maintenance (O&M) expenses. The inputs for this calculation come from the economic model, discussed by Company witness Torpey, used in the evaluation of the Facilities. The facilities' operation and maintenance expenses and the depreciation expense based on a thirty-year life for the wind turbines are discussed in the testimony of Company witness DeRuntz. The return reflects a 52% debt ratio and a 48% equity ratio with a 4.395% cost of debt and a 10% return on equity as discussed in the testimony of Company witness Hollis. When the Facilities are reflected in SWEPCO's Texas rates, the then Commission-approved return on equity, other cost of capital rates, and cost of capital ratios will be used in the revenue requirement calculation.

Q. HOW DO THE ADDITION OF THE SELECTED WIND FACILITIES PRODUCE SAVINGS FOR SWEPCO'S TEXAS CUSTOMERS?

A. First, the addition of the Selected Wind Facilities to SWEPCO's generation mix is expected to lower SWEPCO's energy costs. In the first year (Sundance Facility only), there will be an estimated $3.3 million (Texas retail) reduction in net energy costs (fuel costs reduced by off-system sales) associated with the kWh production from the Sundance Facility. In the second year (all Facilities), there will be an estimated $25.7 million (Texas retail) reduction in net energy costs (fuel costs reduced by off-system sales) associated with the kWh production from all facilities. As discussed by company witness Torpey and summarized in his Errata Exhibit JFT-3, two scenarios were reviewed to identify the energy benefit of the Facilities that is reflected in the rate impact analysis. The first scenario, the "Baseline Case," assumed the Selected Wind Facilities for SWEPCO were not added and the second scenario, the "Project Case," assumed the Selected Wind Facilities are approved and implemented. The total generation costs from the Baseline Case are reflected in the pro-forma revenues in my rate impact analysis and the difference between the Baseline Case and the Project Case generation costs are reflected in the proposed rate impact analysis. Consistent with SWEPCO's current fuel cost recovery, 90% of the off-system sales margins are returned to SWEPCO's customers and reflected in the energy cost savings in the rate impact analysis.

Second, the Selected Wind Facilities are expected to defer future capacity requirements for SWEPCO and result in additional savings to SWEPCO's Texas customers beginning in 2030. Because the capacity savings for SWEPCO do not begin until 2030, my calculation of the impact on major classes for the first four years the Facilities are in service does not show this capacity savings value.

Third, the Selected Wind Facilities will be eligible for federal PTCs during the first ten years of commercial operation. The PTCs will flow through to SWEPCO's customers as an additional benefit valued with a tax gross up. Since the PTCs create a direct reduction to income tax expense, the pre-tax revenue level of the PTCs is determined by applying the applicable tax gross up factor.

Q. WHAT HAPPENS IN THE EVENT THE PRODUCTION TAX CREDITS ARE NOT FULLY UTILIZED IN A GIVEN YEAR?

A. Even though customers will receive the benefit of PTCs earned in any given year, in the event the Company cannot fully utilize PTCs in a given year(s), a DTA will be established on SWEPCO's balance sheet. SWEPCO requests Commission approval to include this DTA in its rate base and revenue requirement in a future proceeding. Because SWEPCO's customers are receiving the benefits of the PTCs as earned by SWEPCO, it is reasonable to also include the DTA associated with the PTCs not used by SWEPCO in its base rate revenue requirement. Company witness Multer discusses PTCs and the DTA in his testimony.

Q. HOW ARE THE SELECTED WIND FACILITIES' REVENUE REQUIREMENT AND THE SAVINGS DESCRIBED ABOVE ALLOCATED TO TEXAS CUSTOMERS?

The revenue requirement of the Facilities along with the cost savings and PTCs in this analysis is allocated to the Texas jurisdiction and retail classes using an estimated energy allocator. An energy allocation matches the costs of the Facilities with the benefits generated by the Facilities and the PTCs earned. Actual Texas jurisdictional and class energy allocation factors will be used when the Facilities are recovered in SWEPCO's rates.

Q. WILL SWEPCO CUSTOMERS SEE A NET DECREASE IN THEIR MONTHLY BILLS IN THE FIRST YEAR OF OPERATION OF THE SELECTED WIND FACILITIES WHILE STILL ALLOWING SWEPCO TO RECOVER THE NEEDED REVENUE REQUIREMENT?

A. Yes. The revenue requirement from the addition of these facilities will be more than offset by the energy savings and credits associated with the federal PTC from the operation of the Selected Wind Facilities. There are net customer savings in 2021, which reflects Sundance only, of approximately $402,000 but rising to approximately $3.9 million in savings for Texas customers in 2022, which is for all three facilities, as shown in ERRATA EXHIBIT JOA-1.

Q. WHAT ARE THE TEXAS CUSTOMER NET BENEFITS OVER THE FIRST FOUR YEARS OF OPERATION?

A. For the first four years of operations, SWEPCO Texas customers would receive a Net Benefit of approximately $16.6 million in savings, as further shown in ERRATA EXHIBIT JOA-1.

Q. WHAT ARE THE TEXAS CUSTOMER NET BENEFITS OVER THE FIRST TEN YEARS OF OPERATION?

A. For the first ten years of operations, SWEPCO Texas customers would receive a Net Benefit of approximately $119.5 million in savings, as further shown on ERRATA EXHIBIT JOA-1.

Q. ARE THERE EXPECTED SAVINGS FOR TEXAS RESIDENTIAL CUSTOMERS FOR THE FIRST FOUR YEARS OF OPERATION?

A. Yes. The calculations showing savings for the average residential customer (1000 kWh) are set forth in ERRATA EXHIBIT JOA-2. This Errata exhibit also shows results of the allocations for the Texas retail jurisdiction and major rate classes through 2024.

IV. COST RECOVERY

Q. HOW WILL THE SELECTED WIND FACILITIES' REVENUE REQUIREMENTS BE RECOVERED FROM SWEPCO'S TEXAS RETAIL CUSTOMERS?

A. In a future filing, SWEPCO intends to request implementation of a Generation Investment Recovery Rider pursuant to newly-enacted Section 36.213 of PURA[2] to recover the revenue requirements of the Selected Wind Facilities. Under § 36.213, an electric utility operating outside of ERCOT may request a rider to recover investment in a power generation facility and the Commission may approve the rider before the utility places the facility into service. Such a rider shall take effect on the date the power generation facility begins providing service to customers, and amounts recovered through the rider are subject to reconciliation in the utility's next base rate proceeding. The Company intends to request that the Rider recover the share of its investment in the Selected Wind Facilities that is allocable to Texas, which is 309 MW.

[2] PURA § 36.213 was recently enacted by the Texas Legislature and signed into law by the Governor. Acts 2019, 86th Leg., R.S., Ch. ___ (H.B. 1397), Sec. 4, eff. June 14, 2019.

Q. HOW WILL THE PTC BENEFITS OF THE SELECTED WIND FACILITIES BE CREDITED TO CUSTOMERS?

A. PTCs are recorded in FERC Account No. 409.1 and, therefore, would normally be credited to customers through base rates. Until the Company's investment in the Selected Wind Facilities is placed into base rates, the Company intends to credit the PTC benefits of the Selected Wind Facilities to customers through the future rider filing discussed above, as an offset to the Facilities' revenue requirements.

Q. HOW WILL THE FUEL AND ENERGY COST SAVINGS OF THE SELECTED WIND FACILITIES BE FLOWED THROUGH TO CUSTOMERS?

A. Fuel and energy-related costs are reconcilable costs that are included in the Company's fuel factor, so those cost savings attributable to the Selected Wind Facilities will be flowed through to customers through future fuel factor adjustment and fuel reconciliation proceedings.

VI. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The Selected Wind Facilities are expected to result in savings and PTCs that will more than offset the fixed cost revenue requirement, resulting in a net decrease in customer costs and bills. SWEPCO intends to request in a future filing a Generation Investment Recovery Rider to recover the revenue requirements of the Selected Wind Facilities.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

SOUTHWESTERN ELECTRIC POWER COMPANY
Summary of Net Customer Benefits ($)
Texas Retail Jurisdiction

Facilities' Revenue Requirement (inc DTA CC)	8 436 051	54 403 233	54 580 422	55 691 540	55 643 346	55 695 533	55 660 302
Project Capacity (Benefit) Cost	-	-	-	-	-	-	-
Project Energy Savings	(3 308 027)	(25 669 980)	(26 657 915)	(27 975 507)	(28 545 721)	(29 131 149)	(29 616 660)
Production Tax Credits	(5 529 968)	(32 655 155)	(33 911 122)	(34 004 029)	(35 167 090)	(35 167 090)	(36 423 057)
Net Customer (Benefit) Cost	(401 944)	(3 921 902)	(5 988 615)	(6 287 997)	(8 069 464)	(8 602 705)	(10 379 416)

Facilities' Revenue Requirement (inc DTA CC)	55 517 876	55 329 269	54 920 139	54 231 178	51 815 469	47 610 706	43 646 879
Project Capacity (Benefit) Cost	-	-	-	-	-	-	-
Project Energy Savings	(43 267 350)	(42 454 290)	(44 025 601)	(45 361 593)	(47 119 032)	(48 553 082)	(50 472 593)
Production Tax Credits	(36 522 846)	(37,679 025)	(37 679 025)	(32 341 569)	-	-	-
Net Customer (Benefit) / Cost	(24 272 320)	(24 804 045)	(26 784 488)	(23 471,983)	4 696 438	(942 376)	(6 825 714)

Facilities' Revenue Requirement (inc DTA CC)	41 532 419	40 725 605	39 935 881	39 155 424	38 463 254	37 769 416	37 066 681
Project Capacity (Benefit) Cost	-	-	(347 735)	(20 689 538)	(21 071 370)	406 308	(21 298 923)
Project Energy Savings	(52 773 816)	(53 508 687)	(55 325 317)	(52 973 373)	(54 567 655)	(60 250 906)	(58 869 969)
Production Tax Credits	-	-	-	-	-	-	-
Net Customer (Benefit) / Cost	(11 241 397)	(12 783 081)	(15 737 170)	(34 507 487)	(37 175 771)	(22 075 182)	(43 102 211)

Facilities' Revenue Requirement (inc DTA CC)	36 501 244	35 706 102	35 003 304	34 279 458	33 647 372	33 024 527	32 529 691
Project Capacity (Benefit) Cost	(20 844 431)	974 686	374 300	150 472	235 503	(19 038 926)	(17 614 205)
Project Energy Savings	(61 355 441)	(65 517 165)	(68 505,679)	(71 827 813)	(73 751 495)	(74 177 342)	(76 719 107)
Production Tax Credits	-	-	-	-	-	-	-
Net Customer (Benefit) / Cost	(45 698 628)	(28,836 376)	(33,128 075)	(37 397 883)	(39 868 621)	(60 191 741)	(61 803 621)

Facilities' Revenue Requirement (inc DTA CC)	32 173,213	32 230 994	30 278 406		1 313 204 935
Project Capacity (Benefit) / Cost	1 134 691	842 091	(1 669 751)		(118 456 828)
Project Energy Savings	(79 102 498)	(80 008 969)	(70 020 676)		(1 601 414 408)
Production Tax Credits	-	-	-		(357 079 976)
Net Customer (Benefit) / Cost	(45 794 595)	(46 935 883)	(41 412 021)		(763 746 277)

SOUTHWESTERN ELECTRIC POWER COMPANY
Impact on Major Rate Classes
Texas Jurisdiction

Revenue Impact

		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Proforma Revenue	Residential	242,007,350	240,606,718	245,261,787	248,952,398	249,220,421
	Commercial	199,598,128	196,376,509	200,071,195	202,637,786	201,702,183
	Industrial	187,961,301	192,833,510	199,912,798	204,042,752	203,971,608
		629,566,778	629,816,738	645,245,779	655,632,937	654,894,212
Project Net (Benefit) Cost	Residential	-	(119,060)	(1,161,711)	(1,773,894)	(1,862,574)
	Commercial	-	(119,758)	(1,168,519)	(1,784,289)	(1,873,489)
	Industrial	-	(163,126)	(1,591,673)	(2,430,432)	(2,551,933)
		-	(401,944)	(3,921,902)	(5,988,615)	(6,287,997)
Total Revenue with Project	Residential	242,007,350	240,487,658	244,100,076	247,178,504	247,357,847
	Commercial	199,598,128	196,256,751	198,902,677	200,853,496	199,828,694
	Industrial	187,961,301	192,670,384	198,321,125	201,612,321	201,419,675
		629,566,778	629,414,793	641,323,877	649,644,321	648,606,216

Rate Impact per kWh

		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Proforma Rate	Residential	0.111007	0.110008	0.111799	0.113268	0.113115
	Commercial	0.090247	0.089262	0.091028	0.092475	0.092325
	Industrial	0.065257	0.064349	0.065976	0.067310	0.067172
		0.086573	0.085297	0.086940	0.088354	0.088207
Project Net (Benefit) Cost	Residential	-	(0.000054)	(0.000530)	(0.000807)	(0.000845)
	Commercial	-	(0.000054)	(0.000532)	(0.000814)	(0.000858)
	Industrial	-	(0.000054)	(0.000525)	(0.000802)	(0.000840)
		-	(0.000054)	(0.000528)	(0.000807)	(0.000847)
Total Rate with Project	Residential	0.111007	0.109954	0.111270	0.112461	0.112270
	Commercial	0.090247	0.089208	0.090496	0.091661	0.091467
	Industrial	0.065257	0.064295	0.065451	0.066509	0.066331
		0.086573	0.085242	0.086411	0.087547	0.087360

Residential Monthly Bill @ 1000 kWh Impact

	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Proforma Bill	$ 111.01	$ 110.01	$ 111.80	$ 113.27	$ 113.11
Project Impact	$ -	$ (0.05)	$ (0.53)	$ (0.81)	$ (0.85)
Bill with Project	$ 111.01	$ 109.95	$ 111.27	$ 112.46	$ 112.27

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?

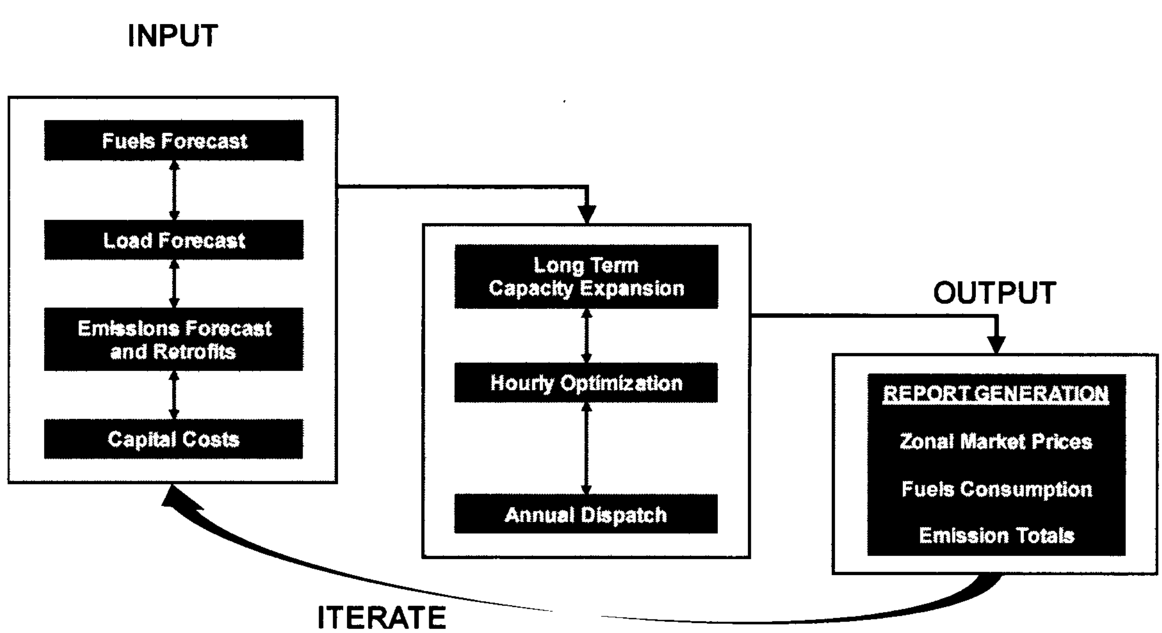
A. The Fundamentals Forecast is a long-term, weather-normalized commodity market forecast. It is not created to meet a specific regulatory need in a particular jurisdiction; rather, it is made available to AEPSC and all AEP operating companies after completion. It is used for purposes such as resource 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.

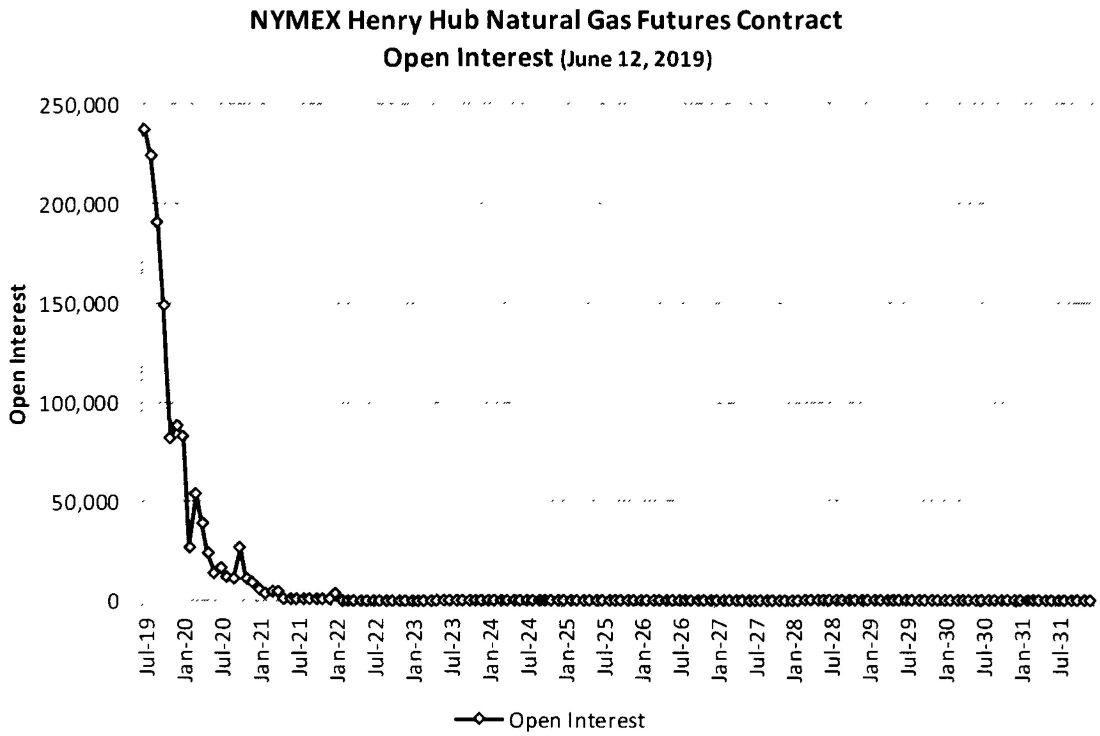
Q. WOULD YOU EXPAND ON OTHER DETAILS ABOUT THE AURORA ENERGY MARKET SIMULATION MODEL?

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.