Control Number: 49737

Item Number: 237

Addendum StartPage: 0

SOAH DOCKET NO. 473-19-6862
PUC DOCKET NO. 49737

APPLICATION OF SOUTHWESTERN ELECTRIC POWER COMPANY FOR CERTIFICATE OF CONVENIENCE AND NECESSITY AUTHORIZATION AND RELATED RELIEF FOR THE ACQUISITION OF WIND GENERATION FACILITIES	**§**	**BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS**

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO OFFICE OF PUBLIC UTILITY COUNSEL'S THIRD REQUEST FOR INFORMATION

JANUARY 15, 2020

TABLE OF CONTENTS

SOAH DOCKET NO. 473-19-6862
PUC DOCKET NO. 49737

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO OFFICE OF PUBLIC UTILITY COUNSEL'S THIRD REQUEST FOR INFORMATION

Question No. 3-1:

Refer to the Direct Testimony of Karl Bletzacker at pages 4-5. Please explain in detail how an in-depth assessment of AEPSC's energy market research information can yield an indication of the supply, demand, and price relationship (price elasticity) over a period of time. Provide all supporting analysis and calculations of price elasticity based on the aforementioned energy market data.

Response No. 3-1:

Price elasticity provides guidance that a change in natural gas consumption is accompanied by an appropriate change in natural gas price and is utilized to confirm that both price and consumption growth rates are in balance. This balance of growth rates can be observed from an assessment of natural gas consumption for the electric generation, residential, commercial and industrial sectors combined with net LNG exports, net pipeline exports and other factors (including lost and unaccounted-for gas), which yields the U'S total natural gas consumption. Natural gas price elasticity, identified in the referenced Bletzacker Direct Testimony, is defined as the % change in total consumption divided by the % change in price. It is the application of natural gas price elasticity to U.S. total natural gas consumption (inclusive of Aurora model-driven values for electric generation sector demand) that impact Fundamentals Forecast prices. Workpapers are not archived, but values have been observed to range from approximately 0.4 - 1.4.

Prepared By: Connie S. Trecazzi — Title: Economic Forecast Anlyst Staff

Sponsored By: Karl R. Bletzacker — Title: Dir Fundamental Analysis

SOAH DOCKET NO. 473-19-6862
PUC DOCKET NO. 49737

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO OFFICE OF PUBLIC UTILITY COUNSEL'S THIRD REQUEST FOR INFORMATION

Question No. 3-2:

Refer to the Direct Testimony of Karl Bletzacker at page 5, line 3. Please explain what "other things" have been derived from AEPSC's energy market data that support its fundamentals model.

Response No. 3-2:

Bletzacker Direct Testimony, page 5, lines 1-4 states; "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." In the context of this sentence of testimony, "other things" include the specific components of natural gas consumption (electric generation, residential, commercial and industrial sectors, net LNG exports, net pipeline exports and other factors (including lost and unaccounted-for gas).

Prepared By: Connie S. Trecazzi — Title: Economic Forecast Anlyst Staff

Sponsored By: Karl R. Bletzacker — Title: Dir Fundamental Analysis

SOAH DOCKET NO. 473-19-6862
PUC DOCKET NO. 49737

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO OFFICE OF PUBLIC UTILITY COUNSEL'S THIRD REQUEST FOR INFORMATION

Question No. 3-3:

Refer to the Direct Testimony of Karl Bletzacker at page 6. Please explain how AEP weather-normalizes its energy market fundamentals forecast. What is the source of the normal heating and cooling degree days? Does AEP use region-specific normal heating and cooling degree days? If not, please explain why not.

Response No. 3-3:

In the Company's Fundamentals Forecast, each SPP zone (SPP Central, SPP KS MO, SPP NE and SPP Dakotas) has its own electric energy load forecast which assumes region-specific normal degree-days. Normal degree-days are guided by National Centers for Environmental Information's latest data.

Prepared By: Connie S. Trecazzi — Title: Economic Forecast Anlyst Staff

Sponsored By: Karl R. Bletzacker — Title: Dir Fundamental Analysis

SOAH DOCKET NO. 473-19-6862
PUC DOCKET NO. 49737

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO OFFICE OF PUBLIC UTILITY COUNSEL'S THIRD REQUEST FOR INFORMATION

Question No. 3-4:

Refer to SWEPCO's response to TIEC RFI 1-4. Regarding the AEP fundamentals forecast, please provide the forecasts of natural gas demand for the electric generation, residential, commercial and industrial sectors, net LNG exports, net pipeline exports and all other demand forecasts that are inputs into the fundamentals model. Please explain if a forecast of natural gas supply is used in the fundamentals model. If a forecast is used, identify the source of the forecast.

Response No. 3-4:

Please refer to TIEC 5-5 for the forecasts of natural gas demand and supply.

Prepared By: Connie S. Trecazzi — Title: Economic Forecast Anlyst Staff

Sponsored By: Karl R. Bletzacker — Title: Dir Fundamental Analysis

SOAH DOCKET NO. 473-19-6862
PUC DOCKET NO. 49737

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO OFFICE OF PUBLIC UTILITY COUNSEL'S THIRD REQUEST FOR INFORMATION

Question No. 3-5:

Refer to SWEPCO's response to OPUC RFI 2-6. Please identify which of the forecasts provided in response to TIEC RFI 1-9 are inputs to, and which forecasts are outputs from, the Aurora model. Please identify the source of the monthly and annual fuel price inputs to the Aurora model.

Response No. 3-5:

TIEC 1-9 requests all AEP Fundamentals Forecasts created during the last ten years. In each of those forecasts, Power prices ($/MWh), Heat Rates (MMBtu/MWh) and Capacity prices ($/MW-day) are all direct outputs of the Aurora model. Emissions ($/ton), Renewable Energy Subsidies ($/MWh) and Inflation Factors are direct inputs to the Aurora model. Fuels prices are not a direct output of the Aurora model, rather the model informs the fuel price forecast by providing hourly fuels consumption for every U.S. electric generator through the iterative process presented in Bletzacker Direct Testimony, page 5.

Prepared By: Connie S. Trecazzi — Title: Economic Forecast Anlyst Staff

Sponsored By: Karl R. Bletzacker — Title: Dir Fundamental Analysis

SOAH DOCKET NO. 473-19-6862
PUC DOCKET NO. 49737

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO OFFICE OF PUBLIC UTILITY COUNSEL'S THIRD REQUEST FOR INFORMATION

Question No. 3-6:

Refer to SWEPCO's response to OPUC RFI 2-9. Please provide any empirical evidence developed by AEP that congestion and loss-related costs would increase from 2021 to 2024 proportionally with the increase in market prices forecasted by the Company in its AURORA-based fundamental forecasts.

Response No. 3-6:

As explained by witness Pfeifenberger, note that 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. These transmission upgrades are expected to *reduce* congestion on the transmission system. At the same time, SPP assumed about 3,000 MW of new wind generation development would occur between 2019 and 2024, in its 2019 ITP PROMOD Reference Case model. New wind generation in SPP will *increase* congestion on the transmission system. The company assumed that SPP's transmission upgrades (through 2024) would be able to maintain system congestion at current levels as new wind generation is added to the SPP system, through 2024. This means that congestion *costs* would largely be driven by market prices (which are driven by dispatch costs, i.e., fuel costs), as explained in Mr. Pfeifenberger's testimony on page 45, lines 3-10. In the Customer Benefits analysis of the Selected Wind Facilities, the 2021-2024 congestion costs will therefore increase proportionally with the increase in market prices forecasted by the Company in its AURORA-based fundamental forecasts.

Prepared By: Shelli A. Sloan — Title: Dir Case Suppt & Special Proj

Sponsored by: Akarsh Sheilendranath — Title: Senior Associate, The Brattle Group

SOAH DOCKET NO. 473-19-6862
PUC DOCKET NO. 49737

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO OFFICE OF PUBLIC UTILITY COUNSEL'S THIRD REQUEST FOR INFORMATION

Question No. 3-7:

Refer to the Direct Testimony of Akarsh Sheilendranath at page 10, lines 19-21. Please provide any empirical evidence developed by AEP showing that congestion and loss-related costs would remain constant from 2030 to 2051 at the 2029 value forecasted by the Company in its AURORA-based fundamental forecasts.

Response No. 3-7:

Please see response to TIEC 2-9.

Prepared By: Shelli A. Sloan — Title: Dir Case Suppt & Special Proj

Sponsored by: Akarsh Sheilendranath — Title: Senior Associate, The Brattle Group

SOAH DOCKET NO. 473-19-6862
PUC DOCKET NO. 49737

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO OFFICE OF PUBLIC UTILITY COUNSEL'S THIRD REQUEST FOR INFORMATION

Question No. 3-8:

Refer to SWEPCO's response to ETEC/NTEC RFI 1-32. SWEPCO states that it does not have a detailed project timeline nor routing plans or options as it is not known if or when a gen-tie may be needed, but given SWEPCO's understanding of the SPP system, please provide SWEPCO's best estimate as to the need and timing of gen-tie lines to any of the proposed wind facilities. Please describe the analysis that AEP would perform to determine whether it was economic in the future to construct gen-tie lines to any of the proposed wind facilities. Please confirm or deny that the net benefit to customers of the wind facilities would be reduced if transmission congestion limits delivery of power from the wind facilities to an amount below the minimum production guarantee.

Response No. 3-8:

SWEPCO will monitor the actual congestion once the wind farms go in service, as well as participate in SPP's regional planning processes. SPP's normal planning processes could identify localized or regional upgrades other than a dedicated gen-tie, which might be able to alleviate higher-than projected congestion levels at a lower cost than that of a gen-tie. To the extent no such non gen-tie options are identified, actual congestion costs will be compared to the Company's estimated revenue requirement for a potential gen-tie, based on the Company's best estimate for cost at the time. The process for computing the revenue requirement of the potential gen-tie will be similar to the process used in this proceeding, as described in the Company's response to OPUC 3-9.

Regarding the gen-tie, the Company does not have a "best estimate" of timing because the Company does not currently expect that a gen-tie will be required based on the forecast market and transmission system conditions reflected in its base case economic benefits analysis.

In the event congestion costs turn out to be higher than forecast in the base case, 2026 is the earliest year the Company estimates it could get the line in service, allowing for time to monitor congestion and then site and build the line. Note that the Company relied on SPP's Reference Case Future for projecting the estimated congestion costs for 2021-2051. Because congestion costs are uncertain—due to significant uncertainties around future generation resource mix in SPP, and the uncertainty about the extent and timing of future SPP transmission upgrades—the company also analyzed a "higher congestion" scenario which would manifest if the SPP-ITP-identified transmission needs would not be addressed. This "higher congestion" scenario was employed for estimating the benefits of the Selected Wind Facilities under a future gen-tie scenario, assuming that the gen-tie would be placed in service by the end of 2026 to alleviate high congestion costs.

However since there is significant uncertainty around future congestion costs depending on how the SPP resource mix and transmission development evolve, the Company is adopting a wait-and-see

approach on developing a tie-line . The Company estimates that a gen-tie would have a revenue requirement of approximately $36 million in its first year in service, if it were to be placed in service at the end of 2026. This cost would be lower than the projected congestion costs under the higher congestion scenario analyzed by the company. The revenue requirement would then decline gradually to $24M annually by 2051. The annual average cost over that 2027-2051 period is forecasted to be $28M. These amounts are shown in witness Torpey's gen-tie cases on line 7 of Exhibit JFT-3 pages 10-12. The cost of the gen-tie is the same regardless of which fundamental pricing scenario is being evaluated. The Company expects the construction cost of the gen-tie would escalate at 2% per year if it were to be placed in service after 2026, resulting in a slightly higher revenue requirement the later it is built.

Regarding congestion, pages 1-9 of Exhibit JFT-3 are 9 "base congestion" scenarios based on combinations of the five different fundamentals forecasts and either a P50 or P95 wind capacity factor, all of which excluded a tie line. Three of the scenarios' expected congestion and loss-related costs (line 2 of each page) are higher than $28M annually and 6 scenarios are lower than $28 million. The Congestion and loss-related costs depend on the underlying energy price, resulting in slight differences from one fundamental case to another.
On line 2 of pages 10-12 of Exhibit JFT-3, are 3 cases based on an assumed "high congestion" scenario in which a gen tie is constructed at the end of 2026 and congestion and loss-related costs are forecasted to be between $28M and $36M from 2027-2051, all of which are at or above the average cost of a gen-tie. The congestion amounts in these three cases for these years are shown as zero on the exhibit itself because the gen-tie is assumed to alleviate the projected congestion and loss costs. These amounts are shown on the Inputs worksheet in the benefits model file (See TIEC 1-19 Supplemental Attachment 1_Torepy_Errata_Workpapers, file-Torpey Errata Benefits Model Final).

The Company confirms that benefits would be lower in the unlikely event that curtailment results in production below the guaranteed level.

Prepared By: Anita A. Sharma	Title: Engineer Staff
Prepared By: Jon R. Maclean	Title: Resource Planning Mgr
Prepared By: James F. Martin	Title: Regulatory Case Mgr
Sponsored By: Kamran Ali	Title: Mng Dir Trans Planning
Sponsored By: John F. Torpey	Title: Mng Dir Res Plnning&Op Anlysis

SOAH DOCKET NO. 473-19-6862
PUC DOCKET NO. 49737

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO OFFICE OF PUBLIC UTILITY COUNSEL'S THIRD REQUEST FOR INFORMATION

Question No. 3-9:

Please reconcile the gen-tie revenue requirement reflected on John Torpey Exhibit JFT-3, pages 10-12, with the gen-tie revenue requirement provided in SWEPCO's response to ETEC/NTEC RFI 1-32.

Response No. 3-9:

The attachment to ETEC/NTEC 1-32 provides the construction cost and O&M estimates for the gen-tie. It does not compute a full revenue requirement. Line 16 on the Gen Tie Cost worksheet in that file was the source of the $444 million construction cost (including AFUDC, assuming beginning of 2021 in service date) used by witness Torpey to produce the tie line costs in Exhibit JFT-3. See Mr. Torpey's workpapers in the file "Torpey Errata Benefits Model Final" provided in Supplemental Attachment 1 to the Company's supplemental response to TIEC 1-19. Mr. Torpey used this cost on rows 57 and 58 of the Inputs worksheet, plus an assumed escalation at 2% per year up through a 2026 in-service date, resulting in a projected $480 million installed cost including AFUDC in 2026. His model then forecasted all of the components of the revenue requirement on the P50 RR base worksheet for each of SWEPCO's jurisdictions. The four jurisdictions were then summed and referenced over to the SWEPCO Exhibits worksheet which was the source of Exhibit JFT-3. Note that cell b12 of the Inputs worksheet in the model must be set to a 1 for the model to display the gen-tie costs in the exhibit.

The other three worksheets in the attachment to ETEC 1-32 (SWEPCO TCOS, PSO TCOS, and Summary) were the source for the tie-line O&M assumption used by witness Torpey at cell B968 of the Inputs worksheet in his benefits model.

Prepared By: Jon R. Maclean	Title: Resource Planning Mgr
Prepared By: James F. Martin	Title: Regulatory Case Mgr
Sponsored By: John F. Torpey	Title: Mng Dir Res Plnning&Op Anlysis

SOAH DOCKET NO. 473-19-6862
PUC DOCKET NO. 49737

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO OFFICE OF PUBLIC UTILITY COUNSEL'S THIRD REQUEST FOR INFORMATION

Question No. 3-10:

Please refer to SWEPCO's response to TIEC RFI 10-1 (j). Please clarify whether the "Panhandle" values shown on Attachment 3 represent the Panhandle futures price index or the Panhandle basis differential.

Response No. 3-10:

TIEC 10-1 Attachment 3, column C, contains the NYMEX Panhandle Natural Gas (Platts IFERC) Basis Futures (as of 11/20/2019). Specifically, it is the value for each contract month equal to the Platts Inside FERC's Gas Market Report ("Platts IFERC") Panhandle Eastern Pipe Line Co., Texas, Oklahoma (mainline) Index ("Index") published in the first regular issue of the contract month minus the Henry Hub Natural Gas Futures contract final settlement price for the corresponding contract month. Please refer to https://www.cmegroup.com/trading/energy/natural-gas/panhandle-natural-gas-basis-swap-futures-platts-iferc_contract_specifications.html.

Prepared By: Connie S. Trecazzi — Title: Economic Forecast Anlyst Staff

Sponsored By: Karl R. Bletzacker — Title: Dir Fundamental Analysis