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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

DIRECT TESTIMONY

AND

WORKPAPERS

OF

KARL NALEPA

ON BEHALF OF THE

OFFICE OF PUBLIC UTILITY COUNSEL

JANUARY 14, 2020

220

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DIRECT TESTIMONY AND WORKPAPERS OF KARL NALEPA

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I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Karl J. Nalepa. I am President of ReSolved Energy Consulting, LLC ("REC"), an independent utility consulting company. My business address is 11044 Research Boulevard, Suite A-420, Austin, Texas 78759.

Q. ON WHOSE BEHALF ARE YOU PRESENTING TESTIMONY IN THIS PROCEEDING?

A. I am presenting testimony on behalf of the Office of Public Utility Counsel ("OPUC").

Q. PLEASE OUTLINE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I have been a partner in REC since July 2011, but joined R.J. Covington Consulting, its predecessor firm, in June 2003. I lead our firm's regulated market practice, where I represent the interests of clients in utility regulatory proceedings, prepare client cost studies, and develop client regulatory filings. Before joining REC, I served for more than five years as an Assistant Director at the Railroad Commission of Texas ("Texas RRC"). In this position, I was responsible for overseeing the economic regulation of natural gas utilities in Texas, which included supervising staff casework, advising Commissioners on regulatory issues, and serving as a Technical Rate Examiner in regulatory proceedings. Prior to joining the Texas RRC, I worked as an independent consultant advising clients on a broad range of electric and natural gas industry issues and then spent five years as a supervising consultant with Resource Management International, Inc. I also served for four years as a Fuel Analyst at the Public Utility Commission of Texas ("PUCT" or "the

Commission"), where I evaluated fuel issues in electric utility rate filings, participated in electric utility-related rulemaking proceedings, and participated in the review of electric utility resource plans. My professional career began with eight years in the reservoir engineering department of Transco Exploration Company, which was an affiliate of Transco Gas Pipeline Company, a major interstate pipeline company.

I hold a Master of Science degree in Petroleum Engineering from the University of Houston and a Bachelor of Science degree in Mineral Economics from Pennsylvania State University. I am also a certified mediator. My Statement of Qualifications is included as Attachment A.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I have testified many times before the Commission, as well as the Texas RRC, on a variety of regulatory issues. I have also provided testimony before the Louisiana Public Service Commission, Arkansas Public Service Commission and Colorado Public Utilities Commission. A summary of my previously filed testimony is included as Attachment B. In addition, I have provided analysis and recommendations in a number of city-level regulatory proceedings that resulted in decisions without written testimony.

II. PURPOSE AND SCOPE

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

A. The purpose of my testimony is to evaluate whether Southwestern Electric Power Company's ("SWEPCO" or "the Company") application to amend its Certificate of Convenience and Necessity ("CCN") to acquire the proposed wind generation facilities is in the public interest and should be granted by the Commission.

Q. WHAT IS THE SCOPE OF YOUR TESTIMONY?

A. My testimony evaluates the costs and benefits of the wind generation projects proposed by SWEPCO in its CCN application.

III. OVERVIEW OF APPLICATION

Q. WHAT IS SWEPCO REQUESTING IN ITS CCN APPLICATION?

A. SWEPCO is seeking the Commission's approval to amend its CCN to include certain wind generation facilities.[1] More specifically, the facilities are comprised of:

Traverse	999 MW
Maverick	287 MW
Sundance	199 MW
Total	1,485 MW

Each of the wind generation facilities is owned by an affiliate of Invenergy LLC and located in Oklahoma. SWEPCO has contracted to acquire 54.5% of each facility, for a total of 810 MW, and the Public Service Company of Oklahoma ("PSO") will acquire the remaining 45.5% (675 MW) share.

Q. WHAT IS THE BASIS FOR SWEPCO'S REQUEST?

A. SWEPCO relies on its most recent Integrated Resource Plan ("IRP") to conclude that customers will benefit from SWEPCO's acquisition of low-cost wind generation resources. The plan purports to show that increases in renewable energy, including wind and solar, over the planning period will provide significant benefits to customers. Under the plan, energy output attributable to wind generation resources increases from 9% to 26% of SWEPCO's total energy mix. As a result, SWEPCO asserts that acquisition of the proposed

[1] Application at 1.

wind generation facilities will reduce its customers' energy costs, help meet its capacity needs, provide renewable energy credits ("RECs") that its customers may desire to acquire, and further diversify its portfolio of supply-side resources.[2]

Q. WHAT ARE THE PROJECTED COSTS OF THE WIND PROJECTS?

A. SWEPCO estimates that the total cost of the proposed wind generation facilities, including all interconnection and upgrade costs, is $1.86 billion ($1,253/kW), of which SWEPCO's 54.5% share is $1.01 billion. Total project costs, including Purchase and Sale Agreement ("PSA") price adjustments and owner's costs are expected to be approximately $1.996 billion ($1,344/kW), of which SWEPCO's 54.5% share is approximately $1.09 billion.[3] The Texas retail jurisdictional estimated cost of the facilities is $415 million.[4]

Q. WHAT ARE THE PROJECTED BENEFITS OF THE WIND PROJECTS?

A. SWEPCO expects the proposed wind generation facilities to provide energy cost savings of approximately $2.03 billion ($567 million net present value), as compared to a baseline case without the facilities. The energy cost savings on a Texas retail basis are $774 million, or $216 million net present value. SWEPCO further asserts that the facilities would provide customer benefits under a wide range of possible future conditions analyzed by the Company and would break even at future power and gas prices below the low range of its forecasts. Notably, the facilities take advantage of federal Production Tax Credits ("PTCs")

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[2] Direct Testimony of Thomas A. Brice at 4.

[3] Application at 4 and Attachment B, *Public Notice.*

[4] $1.996 billion x 54.5% SWEPCO share x 38.11% Texas jurisdictional share = $415 million.

for 80% of the value of the PTCs for Traverse and Maverick, and for Sundance, 100% of the value of the PTCs, which contribute to the asserted cost savings.[5]

Q. WHAT SPECIFIC RELIEF IS SWEPCO REQUESTING IN THIS PROCEEDING?

A. Specifically:[6]

1. SWEPCO requests that the Commission approve its request that its CCN be amended to include acquisition of an 810 MW share of the proposed wind generation facilities as described in its filing.

2. SWEPCO has filed separate applications for certification of the wind generation facilities with the Arkansas Public Service Commission and the Louisiana Public Service Commission. PSO has filed for approval of rate recovery for the wind generation facilities from the Oklahoma Corporation Commission. SWEPCO requests alternative Commission approvals if it does not receive project approvals from the other state regulatory commissions.

3. PTCs for renewable energy generation significantly contribute to the economics of the wind generation facilities. To the extent that the PTCs are not fully used by the Company in a given tax year, SWEPCO requests Commission approval to include any unrealized PTCs in a deferred tax asset that will be included in its rate base in subsequent rate proceedings.

Q. IS SWEPCO OFFERING ANY GUARANTEES REGARDING THE WIND GENERATION FACILITIES' PERFORMANCE?

A. Yes. SWEPCO is offering the following guarantees:[7]

1. *Capital Cost Cap Guarantee*. SWEPCO proposes a cost cap equal to 100% of the aggregated filed capital costs of approximately $1.996 billion (SWEPCO's share would be approximately $1.09 billion), as outlined in its filing. The capital cost cap guarantee has no exceptions, including for force majeure.

2. *Production Tax Credit Eligibility Guarantee*. If PTCs are not received at the 100% level for Sundance and the 80% level for the other two facilities, because a proposed wind facility is determined to be ineligible, customers will be made whole for the value of the

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[5] Application at 5 and *Updated Torpey Errata Benefits Model Final*.

[6] Application at 4-5.

[7] Direct Testimony of Thomas P. Brice at 16-17.

lost PTCs based upon actual production. However, the PTC eligibility guarantee is subject to changes caused by a change in law that affects the federal PTC.

3. *Minimum Production Guarantee.* Beginning in 2022, the Company proposes to provide a guaranteed minimum production level, in aggregate from the proposed wind generation facilities, of an average of 87% (P95 Capacity Factor Case) of the expected output of the facilities over each five-year period for 10 years averaged across all facilities. This scenario represents a 38.1% capacity factor and 4,959 GWh per year, in the aggregate for the wind generation facilities. If the minimum production level is not achieved, customers will be made whole on an energy and PTC (if applicable) basis. However, there is an exception for force majeure and curtailment in the Southwest Power Pool ("SPP").

IV. SUMMARY AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS IN THIS PROCEEDING.

A. SWEPCO's estimate of benefits is very uncertain, while placing all risk on its ratepayers if the claimed benefits do not materialize. Therefore, in order for the Company's CCN application to be in the public interest, the Commission should require that the following conditions be met:

a. The wind generation facilities' total project capital costs must be capped at $1.996 billion, which is inclusive of the purchase price and all associated costs.

b. Customers must receive the benefit in reduced fuel expenses and PTCs based on a P50 minimum wind generation facilities' net capacity factor ("NCF") of 44.01%, regardless of whether the actual NCF is lower.

c. The production guarantee must be in place for the entire 30-year life of the wind generation facilities (not just the first 10 years).

d. The production guarantee must have no exception for force majeure.

e. Customers must be credited for PTCs at the 100% level for Sundance and the 80% level for Traverse and Maverick, regardless of whether or not SWEPCO qualifies for the PTCs.

f. SWEPCO must guarantee minimum energy savings to customers based on its Base Case natural gas price forecast, regardless of actual market prices.

V. BASIS FOR EVALUATION

Q. WHAT STANDARD DID YOU APPLY IN YOUR EVALUATION OF SWEPCO'S CCN APPLICATION?

A. The basis for my evaluation of SWEPCO's CCN application is whether its request is in the public interest. PURA § 37.056 (a) states that the Commission may approve an application and grant a certificate <u>only</u> if it finds that the certificate is necessary for the service, accommodation, convenience, or safety of the public. PURA §37.056 (c)(4)(E) allows the Commission to consider whether the application will also lower costs to consumers.

Q. ARE THERE RISKS TO SWEPCO'S REQUEST?

A. Yes. SWEPCO expects the Project costs to be borne entirely by its ratepayers, and in return its ratepayers retain any energy savings and capacity value. However, while the costs are certain to be substantial, the existence of any net savings is more speculative. Once the Commission authorizes rates to include the proposed wind generation facilities, customers are obligated to repay those costs until the plants are retired by the Company. Conversely, project savings are driven by market conditions, are not guaranteed, and may not last through the life of the facility. Many factors will affect the extent of any market savings, such as how much energy the wind generation facilities produce, the market price of natural gas (which sets the marginal price of electricity), and the market price of electricity (with which the wind energy will compete). Thus, under SWEPCO's proposal, its customers will be responsible for all of the fixed project costs and will bear the entire risk of whether potential energy savings, which are subject to market forces, will materialize.

Q. HOW SHOULD SWEPCO'S REQUEST BE EVALUATED?

A. SWEPCO's request should be evaluated on how robust its assumptions are regarding the magnitude of the project costs and savings. If costs exceed savings under reasonable assumptions other than those applied by SWEPCO, the Commission must conclude that the Project is not in the public interest. Or, if approved, the Commission should establish appropriate conditions so that these unbalanced risks are more evenly shared between the Company and its ratepayers.

VI. EVALUATION OF PROJECT RISKS

Q. HOW WERE THE PROPOSED WIND GENERATION FACILITIES SELECTED?

A. Based on its IRP, SWEPCO issued a Request for Proposal ("RFP") for up to 1,200 MW of wind generation resources in January 2019. PSO, at the same time, issued an identical RFP for up to 1,000 MW of wind generation resources. SWEPCO sought projects on a turnkey basis in which it individually, or together with PSO, would acquire through a PSA all of the equity interests in the project company whose assets consist solely of the selected project.[8] In response to the RFPs, SWEPCO and PSO (together, "the Companies") received 35 bids representing 19 unique wind projects totaling 5,896 MW, on March 1, 2019. Fifteen projects were located in Oklahoma and four projects were located in Texas.[9] The Companies first conducted an eligibility and threshold review of the bids. As a result of the review, 11 of the 19 wind projects, totaling 3,265 MW, passed the eligibility and threshold

[8] Direct Testimony of Jay F. Godfrey at 8.

[9] *Id.* at 12.

requirements outlined in the RFPs. The surviving bids were then ranked based on the economic (weighted 90%) and non-price (weighted 10%) merits of the bids.[10]

Q. HOW WAS THE PROJECT RANKING DETERMINED?

A. The economic analysis that the Companies used to rank the bids consisted of two components: 1) the Levelized Cost of Energy (LCOE, $/MWh) associated with each proposal as calculated by the Companies, and 2) the cost of Transmission Congestion ($/MWh) as determined by the Companies' Transmission Congestion Screening Analysis. The two components were added together to determine the Levelized Adjusted Cost of Energy (LACOE) $/MWh for each bid.[11] Based on the LACOE analysis, the projects were ranked and six projects were identified as being collectively able to meet the Companies' RFP solicitation of a combined 2,200 MW. The impact of the non-price analysis did not change the ranking.[12] Finally, the Companies selected the three projects with the strongest economics – Traverse, Maverick, and Sundance, totaling 1,485 MW.[13]

Q. HOW WAS THE ECONOMIC ANALYSIS CONDUCTED?

A. The Companies determined the LCOE by dividing the present value of the revenue requirements ($) for each project by the respective generation (MWh) over the 30-year study period, producing a levelized cost of energy for each project expressed in $/MWh.[14] The Companies determined transmission congestion and loss-related costs using market

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[10] *Id.* at 13-14.

[11] *Id.* at 15.

[12] *Id.* at 17-18.

[13] *Id.* at 19-20.

[14] Direct Testimony of John F. Torpey at 13.

simulations of the SPP system prepared using SPP's 2019 Integrated Transmission Planning PROMOD models and assumptions. Based on these PROMOD outputs, the Companies calculated congestion and loss-related costs for the wind generation resources using congestion and loss differentials between the individual wind sites and the SPP AEP West load zone to determine the cost impact of congestion and losses on the output from the wind generation resources.[15] Assuming congestion costs increased to the point where additional transmission was necessary, the Companies also estimated the costs of a gen-tie configuration that would connect each project to the AEP West Load zone. These estimated costs were escalated to an assumed in-service year of 2026.[16] The Companies assigned a 50 percent weighting to the congestion costs and gen-tie costs to recognize the uncertainty of future congestion costs.[17] As already mentioned, the LCOE and weighted congestion/gen-tie costs were combined to determine LACOE.

Q. HOW DID SWEPCO CALCULATE THE NET CUSTOMER BENEFITS OF THE PROPOSED WIND GENERATION FACILITIES?

A. Using the production-costing model PLEXOS, SWEPCO developed two cases: a case that assumed the wind generation facilities were not added (the Baseline Case), and a change-case that included the wind generation facilities (Project Case). The Company then compared the difference or "delta" between these two cases for the period modeled, 2021 to 2051. Consistent with its 2018 IRP, other resources were added as needed in both the Baseline Case and Project Case throughout the modeling period to maintain the 12%

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[15] Direct Testimony of Akarsh Sheilendranath at 4.

[16] Direct Testimony of Kamran Ali at 13.

[17] Direct Testimony of Jay F. Godfrey at 16.

reserve margin required by SPP. The models also include the wind generation facilities' capacity values, which were determined using the PLEXOS model.[18]

Q. WHAT IS THE RESULT OF SWEPCO'S MODELING EFFORTS?

A. SWEPCO's Base Case results in net customer benefits of $567 million. This case assumes wind generation at the P50 level, SWEPCO's base natural gas price fundamentals forecast, carbon fee, and no gen-tie capital costs. Table 1 provides the components of the resulting net present value ("NPV") as calculated by SWEPCO:[19]

Table 1

Year	NPV	Total 31 Yr. Nominal
1. Production Cost Savings Excluding Congestion/Losses	$1,660	$5,095
2. Congestion and Losses	($322)	($893)
3. Capacity Value	$70	$311
4. Production Tax Credits, Grossed Up	$630	$963
5. Deferred Tax Asset Carrying Charges	($123)	($212)
6. Wind Facility Revenue Requirement	($1,348)	($3,233)
7. Tie Line Revenue Requirement	$0	$0
8. Total Net Customer Benefits/(Cost)	**$567**	**$2,030**

Q. DID SWEPCO MODEL ANY OTHER CASES?

A. Yes. SWEPCO modeled other cases assuming wind generation at a P95 level, high and low natural gas price fundamentals forecasts, no carbon fee, and adding gen-tie capital costs. Table 2 summarizes the NPV of these cases:[20]

[18] Direct Testimony of John F. Torpey at 17-18.

[19] *Updated Torpey Errata Benefits Model Final,* August 30, 2019.

[20] *Updated Torpey Errata Benefits Model Final,* August 30, 2019.

Table 2

Line	Amounts in Millions	NPV	Total 31 Year Nominal
	P50 Capacity Factor Cases		
1	High Gas With CO2	$718	$2,501
2	Base Gas With CO2	$567	$2,030
3	Base Gas Without CO2	$396	$1,453
4	Low Gas With CO2	$396	$1,532
5	Low Gas Without CO2	$236	$971

Line	Amounts in Millions	NPV	Total 31 Year Nominal
	P95 Capacity Factor Cases		
1	High Gas With CO2	$461	$1,792
2	Base Gas With CO2	$330	$1,386
3	Base Gas Without CO2	$181	$883
4	Low Gas With CO2	$183	$960

	Higher Congestion With Tie Line In Service 2026		
Line	Amounts in Millions	NPV	Total 31 Year Nominal
	P50 Capacity Factor Cases		
1	Base Gas With CO2	$541	$2,025
2	Base Gas Without CO2	$330	$1,285
	P95 Capacity Factor Case		
3	Base Gas Without CO2	$94	$640

Q. DO YOU HAVE ANY CONCERNS WITH THE CASES MODELED?

A. Yes. The value of running sensitivity cases, as was done by SWEPCO, is clear as reflected in Table 2. Certain changes in assumptions have a significant impact on the purported benefits of the wind project.

Q. WHAT MODEL ASSUMPTIONS ARE YOU ADDRESSING?

A. As discussed below, these assumptions include the inclusion of carbon costs, facility generation output, gen-tie costs, and natural gas price forecasts.

A. Carbon Fee Cost

Q. WHY DOES SWEPCO INCLUDE A CO2 (CARBON) FEE IN ITS BENEFITS ANALYSIS?

A. SWEPCO believes that it is "highly likely" that a carbon tax or similar carbon burden will be enacted during the 2021-2051 period.[21]

Q. WHAT LEVEL OF CARBON FEE DID SWEPCO INCLUDE IN ITS ANALYSIS?

A. SWEPCO added a carbon fee of $15 per metric ton to all existing fossil fuel-fired generating units beginning in 2028, escalating at 3.5% per year thereafter. SWEPCO uses this fee as a proxy for CO2 mitigation that may be imposed on the combustion of carbon-based fuels in the future.[22]

Q. IS THERE CURRENTLY A FEDERAL CARBON FEE ON FOSSIL FUEL-FIRED GENERATION?

A. No. SWEPCO asserts that 2021-2023 is the earliest date for a climate proposal to pass through Legislative committee, reach the floor and be approved for eventual passage. Then, assuming an implementation period of approximately five years, 2028 is the earliest projection as to when such legislation could become effective.[23]

Q. WHAT IS THE IMPACT OF A CARBON FEE ON ENERGY PRICES?

A. A CO2 fee would adversely affect the cost of electricity generated by fossil fuels. A CO2 fee could also increase natural gas consumption, which can result in increased natural gas

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[21] Response to TIEC RFI No. 9-4.

[22] Response to TIEC RFI No. 9-3.

[23] *Id.*

prices. Relative to fossil fuels, wind-generated power becomes more valuable, because it has no CO_2 emissions.[24]

Q. WHAT IS THE IMPACT OF INCLUDING A CARBON FEE ON SWEPCO'S BASE CASE ANALYSIS?

A. At the P50 output level, SWEPCO's Base Case without a CO_2 fee results in $171 million lower NPV benefits than does its Base Case with a CO_2 fee. This is a 30% reduction from SWEPCO's Base Case with a CO_2 fee.

Q. IS IT REASONABLE THAT THE BASE CASE BENEFITS INCLUDE A CARBON FEE?

A. No. As SWEPCO points out, the likelihood of any federal climate legislation is very low over the next two years.[25] Any action after that is purely speculative. Thus, with no other changes, the benefit of the wind generation facilities is not $567 million as SWEPCO asserts, but at best only $396 million.

B. Generation Risk

Q. HOW WAS THE GENERATION OUTPUT OF THE WIND GENERATION FACILITIES ESTIMATED?

A. As part of the RFP process, each developer was required to submit, as part of its proposal, an independent assessment of the wind generation resource and expected energy output.[26] The Companies retained Simon Wind Inc. ("Simon Wind"), an experienced consulting

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24 Direct Testimony of Karl R. Bletzacker at 9.

25 Response to TIEC RFI No. 9-3.

26 Direct Testimony of Jay F. Godfrey at 23.

firm, to: (1) independently review the wind generation resource assessments and expected energy output included in each of the developer RFP proposals and make adjustments if necessary; and (2) develop a wind energy resource assessment ("WERA") for each of the proposed wind generation facilities.[27]

Q. WHAT WAS THE RESULT OF SIMON WIND'S WERA?

A. The 5-year results at various probabilities are summarized in Table 3:[28]

Table 3

Traverse		Maverick		Sundance		Combined	
MW:	999	MW:	287	MW:	199	MW:	1485
Net Capacity Factors (%)		***Net Capacity Factors (%)***		***Net Capacity Factors (%)***		***Net Capacity Factors (%)***	
P-Value	5-Year	P-Value	5-Year	P-Value	5-Year	P-Value	5-Year
P99	34.80	P99	37.41	P99	38.03	P99	35.74
P95	37.28	P95	39.57	P95	40.32	P95	38.13
P90	38.64	P90	40.76	P90	41.58	P90	39.45
P75	40.86	P75	42.70	P75	43.63	P75	41.58
P50	43.37	P50	44.89	P50	45.95	P50	44.01
P25	45.48	P25	46.76	P25	47.92	P25	46.06
P10	47.35	P10	48.42	P10	49.66	P10	47.87
P05	48.50	P05	49.44	P05	50.74	P05	48.98
P01	50.58	P01	51.29	P01	52.69	P01	51.00
Net GWh/Year		***Net GWh/Year***		***Net GWh/Year***		***Net GWh/Year***	
P-Value	5-Year	P-Value	5-Year	P-Value	5-Year	P-Value	5-Year
P99	3044.3	P99	939.3	P99	664.3	P99	4647.9
P95	3260.8	P95	993.5	P95	704.2	P95	4958.6
P90	3380.4	P90	1023.4	P90	726.3	P90	5130.1
P75	3574.3	P75	1072.0	P75	762.0	P75	5408.3
P50	3794.0	P50	1127.0	P50	802.6	P50	5723.6
P25	3978.9	P25	1174.1	P25	837.1	P25	5990.1
P10	4142.0	P10	1215.7	P10	867.5	P10	6225.2
P05	4242.6	P05	1241.3	P05	886.3	P05	6370.2
P01	4424.8	P01	1287.7	P01	920.3	P01	6632.8

Q. WHAT DO THE P-VALUES REPRESENT?

[27] *Id.* at 23-24.

[28] *Updated Torpey Errata Benefits Model Final,* tabs *Combined P-Values* and *Individual P-Values,* August 30, 2019.

A. The P-Values are the "probability exceedance values," and represent the probability (i.e., confidence) that a forecasted value is exceeded. For a P99 forecast, the probability of the forecast being exceeded is 99%.[29] SWEPCO's Base Case assumes a P50 level, meaning the facilities will produce more MWh than the expected output 50% of the time and fewer MWh than the expected output 50% of the time.[30]

Q. WHAT ARE NET CAPACITY FACTORS?

A. A Net Capacity Factor ("NCF") is the ratio of the actual output of a generating unit over a period of time to its potential output if it were able to operate at full nameplate generating capacity. This factor is important because it relates to the amount of energy that can be delivered from the wind generation facilities. A higher NCF means more energy is delivered from the facilities to the grid, while a lower NCF means less energy is delivered to the grid.

Q. WHAT IS YOUR CONCERN REGARDING GENERATION RISK?

A. SWEPCO's Base Case assumes the combined wind generation facilities' output at a P50 level, or 5,724 GWh per year. But, SWEPCO also ran sensitivity cases assuming a P95 output level, or 4,959 GWh per year. From Table 2, if the combined wind generation facilities produced power at the P95 level, SWEPCO's Base Case would result in $237 million lower NPV benefits than does its Base Case at the P50 level. This is a 42% reduction from SWEPCO's Base Case at the P50 level. Furthermore, the cumulative impact on the Base Case assuming no CO2 fee and P95 output level reduces the asserted benefits

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[29] Direct Testimony of Jay F. Godfrey at 23.

[30] Direct Testimony of Thomas P. Price at 18.

by $386 million, or more than two-thirds. It is clear that if the wind generation facilities generate at a level less than P50, then SWEPCO's asserted customer benefits are overstated.

C. Gen-Tie Costs

Q. WHY DOES SWEPCO PROVIDE A GEN-TIE CASE?

A. SWEPCO's Base Case does not include the cost of gen-ties. However, the Company explains that 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 the congestion through dedicated transmission upgrades, such as a gen-tie between the proposed wind generation facilities and the Company's Tulsa load center.[31]

Q. HAS SWEPCO ESTIMATED THE ADDITIONAL COST OF CONSTRUCTING GEN-TIES FOR EACH OF THE PROPOSED WIND GENERATION FACILITIES?

A. Yes. Table 4 summarizes these costs for each wind generation facility:[32]

Table 4

	Traverse	Maverick	Sundance	Total
Gen-Tie Cost	$248,452,400	$80,813,460	$76,868,445	$406,134,305
AFUDC @ 9.263%	$23,014,146	$7,485,751	$7,120,324	$37,620,221
Total 2021 Cost	$271,466,546	$88,299,211	$83,988,769	$443,754,526

Q. WHAT IS YOUR CONCERN REGARDING THE COST OF THE GEN-TIES?

[31] Direct Testimony of Johannes P. Pfeifenberger at 35.

[32] Response to ETEC/NTEC RFI No. 1-32.

A. Although SWEPCO is not proposing to install the gen-ties right away, its gen-tie cases assume the gen-ties would be needed and installed in 2026.[33] If the gen-ties are installed, the additional cost further reduces any customer benefit of the wind generation facilities. From Table 2, the gen-tie costs added to SWEPCO's Base Case would lower the NPV benefits by $26 million compared to its Base Case.

Q. DO YOU HAVE ANY OTHER CONCERNS REGARDING CONGESTION RISK?

A. Yes. SWEPCO's selection of the Traverse, Maverick and Sundance wind projects was in part based on an assumed equal weighting of system congestion costs and the cost of a gen-tie, as SWEPCO does not know what congestion costs would be in the future. But as disclosed by SWEPCO, assumptions regarding congestion costs would impact the ranking of the developers' wind proposals. Specifically, comparing only the cost of energy and excluding congestion or gen-tie costs, drops the Traverse and Maverick wind projects from the top of the project rankings. Furthermore, including congestion costs but excluding gen-tie costs, dropped all three wind projects in the project rankings. Only when additional gen-tie costs were considered in the project rankings did the three wind projects rise to the top of the project rankings.[34] These findings underscore the sensitivity of SWEPCO's assumptions regarding congestion mitigation.

D. Natural Gas Price Risk

Q. WHY ARE NATURAL GAS PRICE FORECASTS RELEVANT TO SWEPCO'S REQUEST?

[33] Direct Testimony of Kamran Ali at 13.

[34] Direct Testimony of Johannes P. Pfeifenberger at 26 and response to OPUC RFI No. 2-11.

A. Natural gas price forecasts are relevant because gas prices set the marginal price for electricity in the market. The price for natural gas essentially caps the price for wind generation resources. The higher the gas price, the higher wind prices can go, and this price impact improves the project's customer benefit. Conversely, if gas prices remain low, this results in lower wind energy prices, and thus, reduces the project's customer benefit.

Q. HOW DID SWEPCO DEVELOP THE NATURAL GAS PRICE FORECASTS USED IN ITS MODELS?

A. The natural gas price forecasts were developed as part of American Electric Power Company's ("AEP") fundamentals forecast, which is a long-term, weather-normalized commodity market forecast. Along with a Base Case forecast, AEP provided high and low gas price forecasts and no carbon gas price forecasts to reflect lower and higher North American demand for electric generation and fuels.[35]

Q. HOW DOES A MARKET-BASED FORECAST DIFFER FROM A FUNDAMENTALS FORECAST?

A. A market-based forecast reflects market participants' expectations for future prices. These prices are gathered and reported daily by various outlets. The New York Mercantile Exchange ("NYMEX") provides a daily report of natural gas prices that are not strictly a forecast, but rather a set of future prices at which market participants are willing to enter into natural gas transactions. These prices will move up and down over time as market participants' expectations change. On the other hand, a fundamentals forecast relies on a

[35] Direct Testimony of Karl Bletzacker at 3-4.

model that considers the relationship between fundamental components of the economy. For example, model inputs might include natural gas supply and demand forecasts, forecasts of competing energy resources, and inflation rates. The model will generate a set of gas prices based on the relationship between these inputs.

Q. HOW DO THESE DIFFERENT FORECASTS COMPARE?

A. The fundamentals forecast is derived from forecasts of other components of the economy, so it is only as good as the forecast of these variables. The quality of these input forecasts will drive the quality of the resulting natural gas price forecasts. And once developed, the natural gas price forecasts are fixed until the model is run again with updated inputs. For example, AEP's fundamentals forecast was prepared in early 2019, and has not been updated since then.[36] Conversely, a market-based forecast is constantly updated as market participants consider changes that impact the market. Buyers and sellers of futures contracts set the price for natural gas, and market-based indices are typically used in natural gas supply agreements to set the price at which natural gas is purchased.

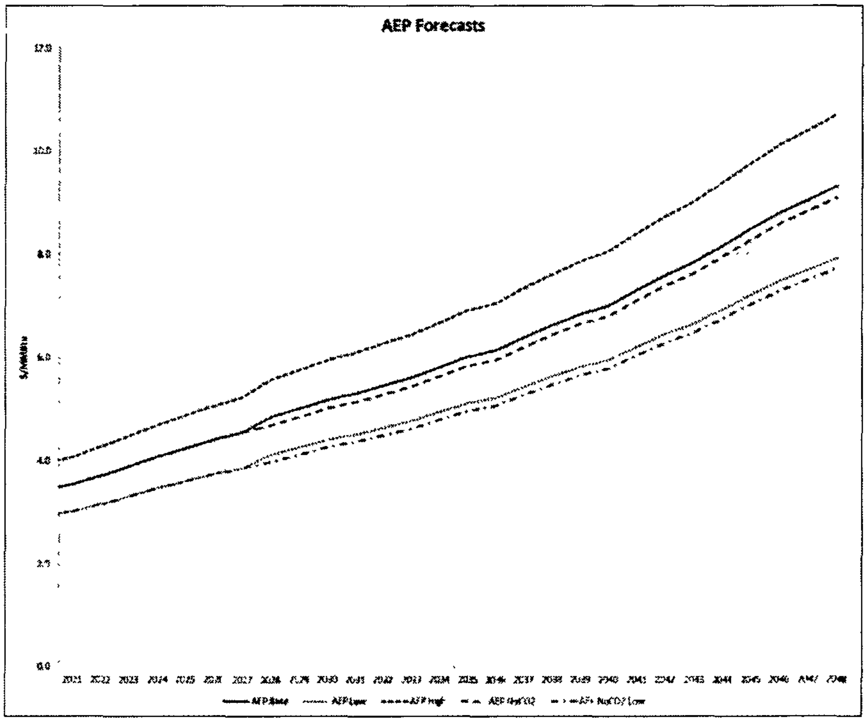
Q. HOW DO THE NATURAL GAS PRICE FORECASTS PROVIDED BY AEP COMPARE?

A. As I mentioned, AEP provided to SWEPCO a Base Case natural gas price forecast, along with lower and upper band forecasts to reflect lower and higher North American demand for electric generation and fuels and further forecasts excluding a carbon fee. The prices are at the Henry Hub, which is located in South Louisiana and is a significant natural gas market hub as well as the pricing point for NYMEX futures prices.

[36] Response to TIEC RFI No. 1-5.

Figure 1 is a graphical presentation of these fundamentals gas price forecasts:[37]

Figure 1



Q. WHAT IS THE IMPACT OF THESE SENSITIVITIES ON THE COMPANY'S NET BENEFITS CALCULATIONS?

A. Table 2 shows that SWEPCO's high gas price forecast increases the Base Case NPV by $151 million, while its low gas price forecast lowered the Base Case NPV by $171 million. Not surprisingly, customer benefits are strongly correlated with gas prices, and as gas prices decline, so do customer benefits.

Q. DID SWEPCO MODEL THE IMPACT ON CUSTOMER BENEFITS OF USING NYMEX FUTURES PRICES?

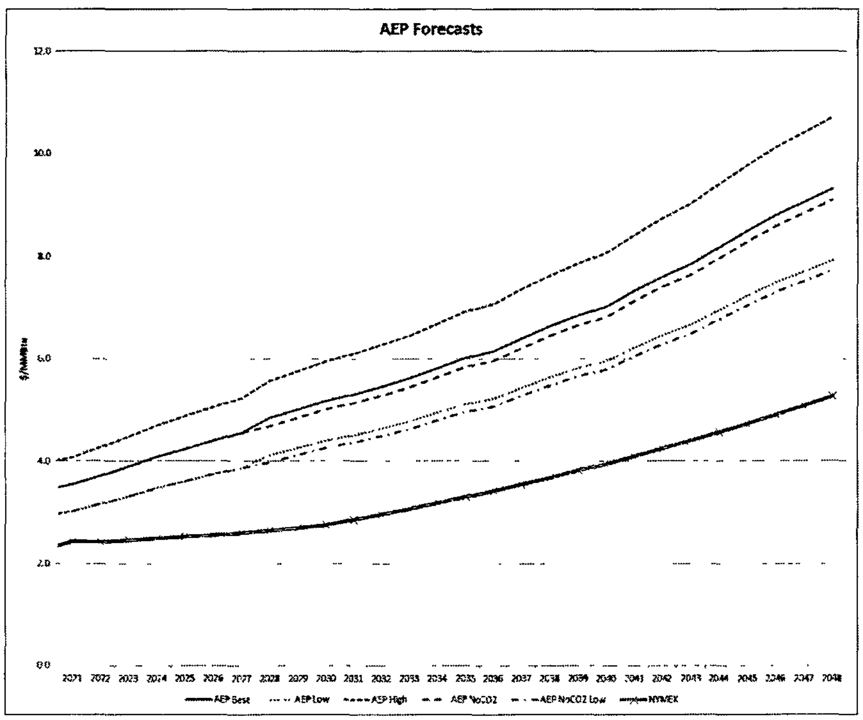
[37] Response to OPUC RFI No. 2-10.

A. No. SWEPCO does not believe that NYMEX futures contract prices are a reliable forecast of future, weather-normalized, long-term energy market prices.[38]

Q. HOW WOULD NYMEX FUTURES PRICES COMPARE TO THE COMPANY'S NATURAL GAS PRICE FORECASTS?

A. I prepared a NYMEX futures price forecast, using settlement prices on Monday, January 6, 2020.[39] NYMEX reports prices through December 2032, so years past 2032 are trended at the annual increase from 2031 to 2032. Figure 2 compares AEP's gas price forecasts against the NYMEX futures prices:

Figure 2



[38] Direct Testimony of Karl R. Bletzacker at 7.

[39] CME Group, Henry Hub Natural Gas Futures Settlements, January 6, 2020.

As can be seen, the NYMEX gas prices are much lower than all of AEP's projected prices throughout the forecast period. Current natural gas prices are in the range of \$2.50/MMBtu, and the NYMEX futures prices suggest that natural gas prices will remain in that range for several years. AEP's Base Case forecast predicts that average natural gas prices will rise nearly 50% by 2021, which seems unlikely given current gas markets.

Q. WHAT CONDITIONS IN THE CURRENT GAS MARKETS MAKE A 50% RISE IN NEAR-TERM NATURAL GAS PRICES UNLIKELY?

A. Natural gas supply continues to grow and this abundant supply has resulted in declining gas prices. According to the U.S. Energy Information Agency ("EIA"), U.S. natural gas production set a new daily production record of 92.8 Bcf/d on August 19, 2019 and natural gas production also set a new monthly record in August 2019, averaging more than 91 Bcf/d for the first time. Overall, U.S. natural gas production increased by 7.1 Bcf/d (8%) between August 2018 and August 2019, led by production gains primarily in the Northeast.[40] Natural gas prices were the lowest in three years, driven by the continued growth in domestic production.[41]

One natural gas market expert, McKinsey & Co., concluded that given modest demand growth and increasingly available gas supply, it expected to see North American gas prices remain stable in the medium term. In addition, as supply from shale gas resources, particularly from associated gas, continues to grow, prices should decline

[40] EIA, *Today in Energy*, September 12, 2019.

[41] *Id.*, January 9, 2020.

slightly, to roughly $2.50 per million British thermal units, and remain at that point for the long-term.[42]

Q. DID SWEPCO CALCULATE A "BREAK EVEN" GAS PRICE FORECAST?

A. Yes. SWEPCO determined the reduction in production cost savings required to result in a zero NPV of customer benefits. The Company estimated the reduction in around-the-clock energy prices that results in a break-even result.[43] The Company then calculated the reduction in natural gas prices that would achieve that energy price reduction by dividing the break-even power prices ($/MWh) by the implied heat rate (MMBtu/MWh).[44]

Q. HOW DID THE BREAK-EVEN GAS PRICE COMPARE TO THE COMPANY'S FUNDAMENTALS GAS PRICE FORECASTS?

A. Figure 3 compares AEP's gas price fundamentals forecasts against SWEPCO's "break-even" forecast:[45]

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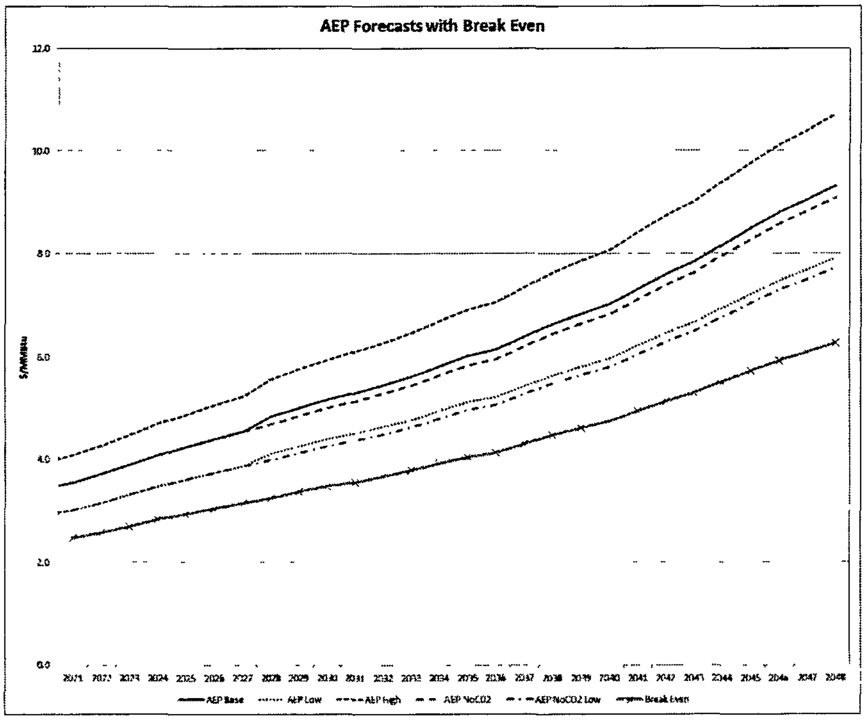
[42] McKinsey & Company, *North American Gas Outlook to 2030*, June 2019.

[43] Direct Testimony of John F. Torpey at 20-21.

[44] Direct Testimony of Karl R. Bletzacker at 15.

[45] *Updated Bletzacker Henry Hub Benchmarks,* August 30, 2019.

Figure 3

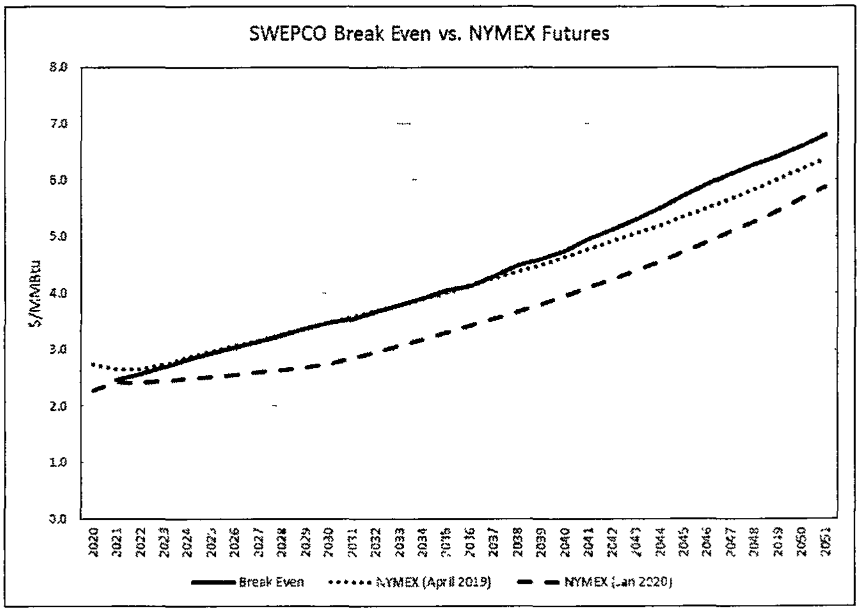


As can be seen in Figure 3, the break-even gas price forecast falls well below AEP's fundamentals price forecasts.

Q. HOW DO THE NYMEX FUTURES PRICES COMPARE TO SWEPCO'S BREAK EVEN PRICE FORECAST?

A. Figure 4 is a comparison of the Company's break-even price forecast and NYMEX futures prices at two points in time: the first is as of April 1, 2019. It appears that the AEP fundamentals forecast was completed in April 2019, so I chose a NYMEX futures strip that was contemporaneous with the AEP forecast. The second forecast is representative of current market prices, taken as of January 4, 2020.

Figure 4



Remember, the Company's "break-even" forecast is the price forecast at which there are no customer benefits. Prices below the break-even forecast result in customer losses – not benefits. As can be seen in Figure 4, the break-even prices already mirrored NYMEX market prices at the time the Company's fundamental forecasts were being completed in April 2019. Today's NYMEX market prices fall well below the break-even forecast. What this means is that at current natural gas prices, the wind generation facilities provide no net benefit to SWEPCO's customers and likely result in increased costs to customers.

Q. SHOULD THE COMMISSION IGNORE THE IMPACT OF NYMEX FUTURES PRICES BECAUSE SWEPCO REJECTS THE USE OF NYMEX PRICES?

A. No, it should not. Certainly, any forecast becomes more uncertain the farther into the future it goes. But it is unchallenged that in the short term, the NYMEX futures prices are a much better reflection of market conditions than are the fundamentals forecasts. Especially considering that as future impacts are discounted in the NPV calculations, the earlier years of the analysis bear more weight. And as shown above, the NYMEX futures prices fall at or below the Company's own break-even analysis, which is the difference between customer benefits and customer losses.

Q. IN A WORST-CASE SCENARIO OF NO CARBON FEE, LESS THAN EXPECTED PLANT PERFORMANCE, NEED FOR A GEN-TIE LINE, AND CONTINUED LOW GAS PRICES, DO THE WIND PROJECTS PROVIDE A BENEFIT OR LOSS FOR CONSUMERS?

A. Realization of each of these risks serves to reduce the customer benefits of the wind projects claimed by SWEPCO. The combined effect of these risks makes the wind projects a significant loss for its consumers.

Q. WHAT DO YOU RECOMMEND IN LIGHT OF THE RISKS YOU DESCRIBE ABOVE?

A. SWEPCO's estimate of benefits is very uncertain, while placing most of the risk on its ratepayers if the claimed benefits do not materialize. SWEPCO has offered certain guarantees that help mitigate some of this risk, but the limited offer is not an adequate safeguard for its ratepayers. Therefore, in order for the Company's CCN application to be in the public interest, the Commission should require that the following conditions be met:

a. The wind generation facilities' total project capital costs must be capped at $1.996 billion, which is inclusive of the purchase price and all associated costs. SWEPCO has already offered this guarantee in its request.

b. Customers must receive the benefits in reduced fuel expenses and PTCs based on a P50 minimum wind generation facilities' net capacity factor (NCF) of 44.01%, regardless of whether the actual NCF is lower. SWEPCO offered to provide a guaranteed minimum production level at the average P95 level. As this level, the Company anticipates exceeding the anticipated output 95% of the time, it is not much of a commitment.

c. The production guarantee must be in place for the entire 30-year life of the wind generation facilities (not just the first 10 years). The production guarantee should be for the life of the facilities to match the base rate cost burden on customers. Furthermore, PSO, SWEPCO's sister company, agreed to a production guarantee for the life of the facilities in its proposed settlement in its Oklahoma jurisdiction.

d. The production guarantee must have no exception for force majeure. These events would necessarily reduce the benefits anticipated under SWEPCO's filing. Furthermore, PSO agreed to exclude force majeure events in its proposed settlement in its Oklahoma jurisdiction.

e. Customers must be credited for PTCs at the 100% level for Sundance and the 80% level for Traverse and Maverick, regardless of whether or not SWEPCO qualifies for the PTCs. SWEPCO has already offered this guarantee in its request.

f. SWEPCO must guarantee minimum energy savings to customers based on its Base Case natural gas price forecast, regardless of actual market prices. As has been shown, natural gas prices have a significant impact on the anticipated customer benefits. Thus, to secure these customer benefits, it is reasonable that the minimum energy savings to customers reflect SWEPCO's Base Case natural gas price, regardless if actual market prices are much lower.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

ATTACHMENTS

ATTACHMENT A

STATEMENT OF QUALIFICATIONS

KARL J. NALEPA

Mr. Nalepa is an energy economist with more than 35 years of private and public sector experience in the electric and natural gas industries. He has extensive experience analyzing utility rate filings and resource plans with particular focus on fuel and power supply requirements, quality of fuel supply management, and reasonableness of energy costs. Mr. Nalepa developed peak demand and energy forecasts for public utilities and has forecast the price of natural gas in ratemaking and resource plan evaluations. He led a management and performance review of the Texas Public Utility Commission, and has conducted performance reviews and valuation studies of municipal utility systems. Mr. Nalepa previously directed the Railroad Commission of Texas' Regulatory Analysis & Policy Section, with responsibility for preparing timely natural gas industry analysis, managing ratemaking proceedings, mediating informal complaints, and overseeing consumer complaint resolution. He has prepared and defended expert testimony in both administrative and civil proceedings, and has served as a technical examiner in natural gas rate proceedings.

EDUCATION

1998 Certificate of Mediation
Dispute Resolution Center, Austin

1989 NARUC Regulatory Studies Program
Michigan State University

1988 M.S. - Petroleum Engineering
University of Houston

1980 B.S. - Mineral Economics
Pennsylvania State University

PROFESSIONAL HISTORY

2011 - ReSolved Energy Consulting
Partner

2003 - 2011 RJ Covington Consulting
Managing Director

1997 – 2003 Railroad Commission of Texas
Asst. Director, Regulatory Analysis & Policy

1995 – 1997 Karl J. Nalepa Consulting
Principal

1992 – 1995 Resource Management International, Inc.
Supervising Consultant

1988 – 1992 Public Utility Commission of Texas
Fuels Analyst

1980 – 1988 Transco Exploration Company
Reservoir and Evaluation Engineer

AREAS OF EXPERTISE

Regulatory Analysis

Electric Power: Analyzed electric utility rate, certification, and resource forecast filings. Assessed the quality of fuel supply management, and reasonableness of fuel costs recovered from ratepayers. Projected the cost of fuel and purchased power. Estimated the impact of environmental costs on utility resource selection. Participated in regulatory rulemaking activities. Provided expert staff testimony in a number of proceedings before the Texas Public Utility Commission.

As consultant, represent interests of municipal clients intervening in large utility rate proceedings through analysis of filings and presentation of testimony before the Public Utility Commission. Also assist municipal utilities in preparing and defending requests to change rates and other regulatory matters before the Public Utility Commission.

Natural Gas: Directed the economic regulation of gas utilities in Texas for the Railroad Commission of Texas. Responsible for monitoring, analyzing and reporting on conditions and events in the natural gas industry. Managed Commission staff representing the public interest in contested rate proceedings before the Railroad Commission, and acted as technical examiner on behalf of the Commission. Mediated informal disputes between industry participants and directed handling of customer billing and service complaints. Oversaw utility compliance filings and staff rulemaking initiatives. Served as a policy advisor to the Commissioners.

As consultant, represent interests of municipal clients intervening in large utility rate proceedings through analysis of filings and presentation of testimony before the cities and Railroad Commission. Also assist small utilities in preparing and defending requests to change rates and other regulatory matters before the Railroad Commission.

Litigation Support

Retained to support litigation in natural gas contract disputes. Analyzed the results of contract negotiations and competitiveness of gas supply proposals considering gas market conditions contemporaneous with the period reviewed. Supported litigation related to alleged price discrimination related to natural gas sales for regulated customers. Provided analysis of regulatory and accounting issues related to ownership of certain natural gas distribution assets in support of litigation against a natural gas utility. Supported independent power supplier in binding arbitration regarding proper interpretation of a natural gas transportation contract. Provided expert witness testimony in administrative and civil court proceedings.

Utility System Assessment

Led a management and performance review of the Public Utility Commission. Conducted performance reviews and valuation studies of municipal utility systems. Assessed ability to compete in the marketplace, and recommended specific actions to improve the competitive position of the utilities. Provided comprehensive support in the potential sale of a municipal gas system, including preparation of a valuation study and all activities leading to negotiation of contract for sale and franchise agreements.

Energy Supply Analysis

Reviewed system requirements and prepared requests for proposals (RFPs) to obtain natural gas and power supplies for both utility and non-utility clients. Evaluated submittals under alternative demand and market conditions, and recommended cost-effective supply proposals. Assessed supply strategies to determine optimum mix of available resources.

Econometric Forecasting

Prepared econometric forecasts of peak demand and energy for municipal and electric cooperative utilities in support of system planning activities. Developed forecasts at the rate class and substation levels. Projected price of natural gas by individual supplier for Texas electric and natural gas utilities to support review of utility resource plans.

Reservoir Engineering

Managed certain reserves for a petroleum exploration and production company in Texas. Responsible for field surveillance of producing oil and natural gas properties, including reserve estimation, production forecasting, regulatory reporting, and performance optimization. Performed evaluations of oil and natural gas exploration prospects in Texas and Louisiana.

PROFESSIONAL MEMBERSHIPS

Society of Petroleum Engineers
International Association for Energy Economics
United States Association for Energy Economics

SELECT PUBLICATIONS, PRESENTATIONS, AND TESTIMONY

"Summary of the USAEE Central Texas Chapter's Workshop entitled 'EPA's Proposed Clean Power Plan Rules: Economic Modeling and Effects on the Electric Reliability of Texas Region,'" with Dr. Jay Zarnikau and Mr. Neil McAndrews, USAEE Dialogue, May 2015

"Public Utility Ratemaking," EBF 401: Strategic Corporate Finance, The Pennsylvania State University, September 2013

"What You Should Know About Public Utilities," EBF 401: Strategic Corporate Finance, The Pennsylvania State University, October 2011

"Natural Gas Markets and the Impact on Electricity Prices in ERCOT," Texas Coalition of Cities for Fair Utility Issues, Dallas, October 2008

"Natural Gas Regulatory Policy in Texas," Hungarian Oil and Gas Policy Business Colloquium, U.S. Trade and Development Agency, Houston, May 2003

"Railroad Commission Update," Texas Society of Certified Public Accountants, Austin, April 2003

"Gas Utility Update," Railroad Commission Regulatory Expo and Open House, October 2002

"Deregulation: A Work in Progress," Interview by Karen Stidger, *Gas Utility Manager*, October 2002

"Regulatory Overview: An Industry Perspective," Southern Gas Association's Ratemaking Process Seminar, Houston, February 2001

"Natural Gas Prices Could Get Squeezed," with Commissioner Charles R. Matthews, *Natural Gas*, December 2000

"Railroad Commission Update," Texas Society of Certified Public Accountants, Austin, April 2000

"A New Approach to Electronic Tariff Access," Association of Texas Intrastate Natural Gas Pipeline Annual Meeting, Houston, January 1999

"A Texas Natural Gas Model," United States Association for Energy Economics North American Conference, Albuquerque, 1998

"Texas Railroad Commission Aiding Gas Industry by Updated Systems, Regulations," *Natural Gas,* July 1998

"Current Trends in Texas Natural Gas Regulation," Natural Gas Producers Association, Midland, 1998

"An Overview of the American Petroleum Industry," Institute of International Education Training Program, Austin, 1993

Direct testimony in PUC Docket No. 10400 summarized in *Environmental Externality,* Energy Research Group for the Edison Electric Institute, 1992

"God's Fuel - Natural Gas Exploration, Production, Transportation and Regulation," with Danny Bivens, Public Utility Commission of Texas Staff Seminar, 1992

"A Summary of Utilities' Positions Regarding the Clean Air Act Amendments of 1990," Industrial Energy Technology Conference, Houston, 1992

"The Clean Air Act Amendments of 1990," Public Utility Commission of Texas Staff Seminar, 1992

ATTACHMENT B

PREVIOUSLY FILED TESTIMONY

KARL J. NALEPA
TESTIMONY FILED

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
Before the Public Utility Commission of Texas					
50110	Dec 19	Denton Municipal Electric	Denton Municipal Electric	Interim TCOS	Wholesale Transmission Rate
49594	Jul 19	Oncor Cities	Oncor Electric Delivery	EECRF	EECRF Methodology
49592	Jul 19	AEP Cities	AEP Texas Inc.	EECRF	EECRF Methodology
49586	Jul 19	TNMP Cities	Texas-New Mexico Power	EECRF	EECRF Methodology
49583	Aug 19	Gulf Coast Coalition	CenterPoint Energy Houston	EECRF	EECRF Methodology
49496	Jun 19	City of El Paso	El Paso Electric	EECRF	EECRF Methodology
49494	Jul 19	AEP Cities	AEP Texas Inc.	Cost of Service	Plant Additions
49421	Jun 19	Office of Public Counsel	CenterPoint Energy Houston	Cost of Service	Cost of Service
49395	May 19	City of El Paso	El Paso Electric	DCRF	DCRF Methodology
49148	Apr 19	City of El Paso	El Paso Electric	TCRF	TCRF Methodology
49042	Mar 19	SWEPCO Cities	SWEPCO	TCRF	TCRF Methodology
49041	Feb 19	SWEPCO Cities	SWEPCO	DCRF	DCRF Methodology
48973	May 19	Xcel Municipalities	Southwestern Public Service	Fuel Reconciliation	Fuel / Purch Power Costs
48963	Dec 18	Denton Municipal Electric	Denton Municipal Electric	Interim TCOS	Wholesale Transmission Rate
48420	Aug 18	Gulf Coast Coalition	CenterPoint Energy Houston	EECRF	EECRF Methodology
48404	Jul 18	Cities	Texas-New Mexico Power	EECRF	EECRF Methodology
48371	Aug 18	Cities	Entergy Texas Inc.	Cost of Service	Cost of Service
48231	May 18	Cities	Oncor Electric Delivery	DCRF	DCRF Methodology

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
48226	May 18	Gulf Coast Coalition	CenterPoint Energy Houston	DCRF	DCRF Methodology
48222	Apr 18	Cities	AEP Texas Inc.	DCRF	DCRF Methodology
47900	Dec 17	Denton Municipal Electric	Denton Municipal Electric	Interim TCOS	Wholesale Transmission Rate
47527	Apr 18	Xcel Municipalities	Southwestern Public Service	Cost of Service	Cost of Service
47461	Dec 17	Office of Public Counsel	SWEPCO	CCN	Public Interest Review
47236	Jul 17	Cities	AEP Texas	EECRF	EECRF Methodology
47235	Jul 17	Cities	Oncor Electric Delivery	EECRF	EECRF Methodology
47217	Jul 17	Cities	Texas-New Mexico Power	EECRF	EECRF Methodology
47032	May 17	Gulf Coast Coalition	CenterPoint Energy Houston	DCRF	DCRF Methodology
46936	Oct 17	Xcel Municipalities	Southwestern Public Service	CCN	Public Interest Review
46449	Apr 17	Cities	SWEPCO	Cost of Service	Cost of Service
46348	Sep 16	Denton Municipal Electric	Denton Municipal Electric	Interim TCOS	Wholesale Transmission Rate
46238	Jan 17	Office of Public Counsel	Oncor Electric Delivery	STM	Public Interest Review
46076	Dec 16	Cities	Entergy Texas Inc.	Fuel Reconciliation	Fuel Cost
46050	Aug 16	Cities	AEP Texas	STM	Public Interest Review
46014	Jul 16	Gulf Coast Coalition	CenterPoint Energy Houston	EECRF	EECRF Methodology
45788	May 16	Cities	AEP-TNC	DCRF	DCRF Methodology
45787	May 16	Cities	AEP-TCC	DCRF	DCRF Methodology
45747	May 16	Gulf Coast Coalition	CenterPoint Energy Houston	DCRF	DCRF Methodology
45712	Apr 16	Cities	SWEPCO	DCRF	DCRF Methodology
45691	Jun 16	Cities	SWEPCO	TCRF	TCRF Methodology

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
45414	Feb 17	Office of Public Counsel	Sharyland	Cost of Service	Cost of Service
45248	May 16	City of Fritch	City of Fritch	Cost of Service (water)	Cost of Service
45084	Nov 15	Cities	Entergy Texas Inc.	TCRF	TCRF Methodology
45083	Oct 15	Cities	Entergy Texas Inc.	DCRF	DCRF Methodology
45071	Aug 15	Denton Municipal Electric	Denton Municipal Electric	Interim TCOS	Wholesale Transmission Rate
44941	Dec 15	City of El Paso	El Paso Electric	Cost of Service	CEP Adjustments
44677	Jul 15	City of El Paso	El Paso Electric	EECRF	EECRF Methodology
44572	May 15	Gulf Coast Coalition	CenterPoint Energy Houston	DCRF	DCRF Methodology
44060	May 15	City of Frisco	Brazos Electric Coop	CCN	Transmission Cost Recovery
43695	May 15	Pioneer Natural Resources	Southwestern Public Service	Cost of Service	Cost Allocation
43111	Oct 14	Cities	Entergy Texas Inc.	DCRF	DCRF Methodology
42770	Aug 14	Denton Municipal Electric	Denton Municipal Electric	Interim TCOS	Wholesale Transmission Rate
42485	Jul 14	Cities	Entergy Texas Inc.	EECRF	EECRF Methodology
42449	Jul 14	City of El Paso	El Paso Electric	EECRF	EECRF Methodology
42448	Jul 14	Cities	SWEPCO	TCRF	Transmission Cost Recovery Factor
42370	Dec 14	Cities	SWEPCO	Rate Case Expenses	Rate Case Expenses
41791	Jan 14	Cities	Entergy Texas Inc.	Cost of Service	Cost of Service/Fuel
41539	Jul 13	Cities	AEP Texas North	EECRF	EECRF Methodology
41538	Jul 13	Cities	AEP Texas Central	EECRF	EECRF Methodology
41444	Jul 13	Cities	Entergy Texas Inc.	EECRF	EECRF Methodology
41223	Apr 13	Cities	Entergy Texas Inc.	ITC Transfer	Public Interest Review

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
40627	Nov 12	Austin Energy	Austin Energy	Cost of Service	General Fund Transfers
40443	Dec 12	Office of Public Counsel	SWEPCO	Cost of Service	Cost of Service/Fuel
40346	Jul 12	Cities	Entergy Texas Inc.	Join MISO	Public Interest Review
39896	Mar 12	Cities	Entergy Texas Inc.	Cost of Service/ Fuel Reconciliation	Cost of Service/ Nat Gas/ Purch Power
39366	Jul 11	Cities	Entergy Texas Inc.	EECRF	EECRF Methodology
38951	Feb 12	Cities	Entergy Texas Inc.	CGS Tariff	CGS Costs
38815	Sep 10	Denton Municipal Electric	Denton Municipal Electric	Interim TCOS	Wholesale Transmission Rate
38480	Nov 10	Cities	Texas-New Mexico Power	Cost of Service	Cost of Service/Rate Design
37744	Jun 10	Cities	Entergy Texas Inc.	Cost of Service/ Fuel Reconciliation	Cost of Service/ Nat Gas/ Purch Power/ Gen
37580	Dec 09	Cities	Entergy Texas Inc.	Fuel Refund	Fuel Refund Methodology
36956	Jul 09	Cities	Entergy Texas Inc.	EECRF	EECRF Methodology
36392	Nov 08	Texas Municipal Power	Texas Municipal Power	Interim TCOS	Wholesale Transmission Rate
35717	Nov 08	Cities Steering Committee	Oncor Electric Delivery	Cost of Service	Cost of Service/Rate Design
34800	Apr 08	Cities	Entergy Gulf States	Fuel Reconciliation	Natural Gas/Coal/Nuclear
16705	May 97	North Star Steel	Entergy Gulf States	Fuel Reconciliation	Natural Gas/Fuel Oil
10694	Jan 92	PUC Staff	Midwest Electric Coop	Revenue Requirements	Depreciation/ Quality of Service
10473	Sep 91	PUC Staff	HL&P	Notice of Intent	Environmental Costs
10400	Aug 91	PUC Staff	TU Electric	Notice of Intent	Environmental Costs
10092	Mar 91	PUC Staff	HL&P	Fuel Reconciliation	Natural Gas/Fuel Oil

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
10035	Jun 91	PUC Staff	West Texas Utilities	Fuel Reconciliation Fuel Factor	Natural Gas Natural Gas/Fuel Oil/Coal
9850	Feb 91	PUC Staff	HL&P	Revenue Req. Fuel Factor	Natural Gas/Fuel Oil/ETSI Natural Gas/Coal/Lignite
9561	Aug 90	PUC Staff	Central Power & Light	Fuel Reconciliation Revenue Requirements Fuel Factor	Natural Gas Natural Gas/Fuel Oil Natural Gas
9427	Jul 90	PUC Staff	LCRA	Fuel Factor	Natural Gas
9165	Feb 90	PUC Staff	El Paso Electric	Revenue Requirements Fuel Factor	Natural Gas/Fuel Oil Natural Gas
8900	Jan 90	PUC Staff	SWEPCO	Fuel Reconciliation Fuel Factor	Natural Gas Natural Gas
8702	Sep 89 Jul 89	PUC Staff	Gulf States Utilities	Fuel Reconciliation Revenue Requirements Fuel Factor	Natural Gas/Fuel Oil Natural Gas/Fuel Oil Natural Gas/Fuel Oil
8646	May 89 Jun 89	PUC Staff	Central Power & Light	Fuel Reconciliation Revenue Requirements Fuel Factor	Natural Gas Natural Gas/Fuel Oil Natural Gas
8588	Aug 89	PUC Staff	El Paso Electric	Fuel Reconciliation	Natural Gas

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
Before the Railroad Commission of Texas					
10900	Nov 19	Cities Steering Committee	Atmos Energy Triangle	Cost of Service	Cost of Service
10899	Sep 19	NatGas, Inc.	NatGas, Inc.	Cost of Service	Cost of Service/Rate Design
10737	Jun 18	T&L Gas Co.	T&L Gas Co.	Cost of Service	Cost of Service/Rate Design
10622	Apr 17	LDC, LLC	LDC, LLC	Cost of Service	Cost of Service/Rate Design
10617	Mar 17	Onalaska Water & Gas	Onalaska Water & Gas	Cost of Service	Cost of Service/Rate Design
10580	Mar 17	Cities Steering Committee	Atmos Pipeline Texas	Cost of Service	Cost of Service/Rate Design
10567	Feb 17	Gulf Coast Coalition	CenterPoint Energy Entex	Cost of Service	Cost of Service/Rate Design
10506	Jun 16	City of El Paso	Texas Gas Service	Cost of Service	Cost of Service/Energy Efficiency
10498	Feb 16	NatGas, Inc.	NatGas, Inc.	Cost of Service	Cost of Service/Rate Design
10359	Jul 14	Cities Steering Committee	Atmos Energy Mid Tex	Cost of Service	Cost of Service/Rate Design
10295	Oct 13	Cities Steering Committee	Atmos Pipeline Texas	Revenue Rider	Rider Renewal
10242	Jan 13	Onalaska Water & Gas	Onalaska Water & Gas	Cost of Service	Cost of Service/Rate Design
10196	Jul 12	Bluebonnet Natural Gas	Bluebonnet Natural Gas	Cost of Service	Cost of Service/Rate Design
10190	Jan 13	City of Magnolia, Texas	Hughes Natural Gas	Cost of Service	Cost of Service/Rate Design
10174	Aug 12	Cities Steering Committee	Atmos Energy West Texas	Cost of Service	Cost of Service/Rate Design
10170	Aug 12	Cities Steering Committee	Atmos Energy Mid Tex	Cost of Service	Cost of Service/Rate Design
10106	Oct 11	Gulf Coast Coalition	CenterPoint Energy Entex	Cost of Service	Cost of Service/Rate Design
10083	Aug 11	City of Magnolia, Texas	Hughes Natural Gas	Cost of Service	Cost of Service/Rate Design
10038	Feb 11	Gulf Coast Coalition	CenterPoint Energy Entex	Cost of Service	Cost of Service/Rate Design
10021	Oct 10	AgriTex Gas, Inc.	AgriTex Gas, Inc.	Cost of Service	Cost of Service/Rate Design

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
10000	Dec 10	Cities Steering Committee	Atmos Pipeline Texas	Cost of Service	Cost of Service/Rate Design
9902	Oct 09	Gulf Coast Coalition	CenterPoint Energy Entex	Cost of Service	Cost of Service/Rate Design
9810	Jul 08	Bluebonnet Natural Gas	Bluebonnet Natural Gas	Cost of Service	Cost of Service/Rate Design
9797	Apr 08	Universal Natural Gas	Universal Natural Gas	Cost of Service	Cost of Service/Rate Design
9732	Jul 08	Cities Steering Committee	Atmos Energy Corp.	Gas Cost Review	Natural Gas Costs
9670	Oct 06	Cities Steering Committee	Atmos Energy Corp.	Cost of Service	Affiliate Transactions/ O&M Expenses/GRIP
9667	Nov 06	Oneok Westex Transmission	Oneok Westex Transmission	Abandonment	Abandonment
9598	Sep 05	Cities Steering Committee	Atmos Energy Corp.	GRIP Appeal	GRIP Calculation
9530	Apr 05	Cities Steering Committee	Atmos Energy Corp.	Gas Cost Review	Natural Gas Costs
9400	Dec 03	Cities Steering Committee	TXU Gas Company	Cost of Service	Affiliate Transactions/ O&M Expenses/Capital Costs

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
Before the Louisiana Public Service Commission					
U-34344/ U-34717	Apr 18	PSC Staff	Dixie Electric Member Corporation	Formula Rate Plan	Stipulation
U-34344	Jan 18	PSC Staff	Dixie Electric Member Corporation	Formula Rate Plan	Adjusted Revenues
U-33633	Nov 15	PSC Staff	Entergy Louisiana, LLC/ Entergy Gulf States Louisiana	Resource Certification	Prudence
U-33033	Jul 14	PSC Staff	Entergy Louisiana, LLC/ Entergy Gulf States Louisiana	Resource Certification	Revenue Requirement
U-31971	Nov 11	PSC Staff	Entergy Louisiana, LLC/ Entergy Gulf States Louisiana	Resource Certification	Certification/Cost Recovery
Before the Arkansas Public Service Commission					
O7-105-U	Mar 08	Arkansas Customers	CenterPoint Energy, Inc. & pipelines serving CenterPoint	Gas Cost Complaint	Prudence / Cost Recovery
Before the Colorado Public Utilities Commission					
18A-0791E	Mar 19	Pueblo County	Black Hills Colorado Electric	Economic Development Rate	Tariff Issues

WORKPAPERS

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

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

Question No. 2-10:

Refer to the direct testimony of Johannes Pfeifenberger at page 8. Please provide the ABB-developed natural gas price forecasts used in the SPP PROMOD simulations, with all supporting workpapers. Are the ABB-developed forecasts the same as the SPP 2019 Integrated Transmission Planning natural gas price forecast reflected on Figure 4 of Mr. Bletzacker's direct testimony? If the forecasts are not the same, please explain why SPP is using different forecasts.

Response No. 2-10:

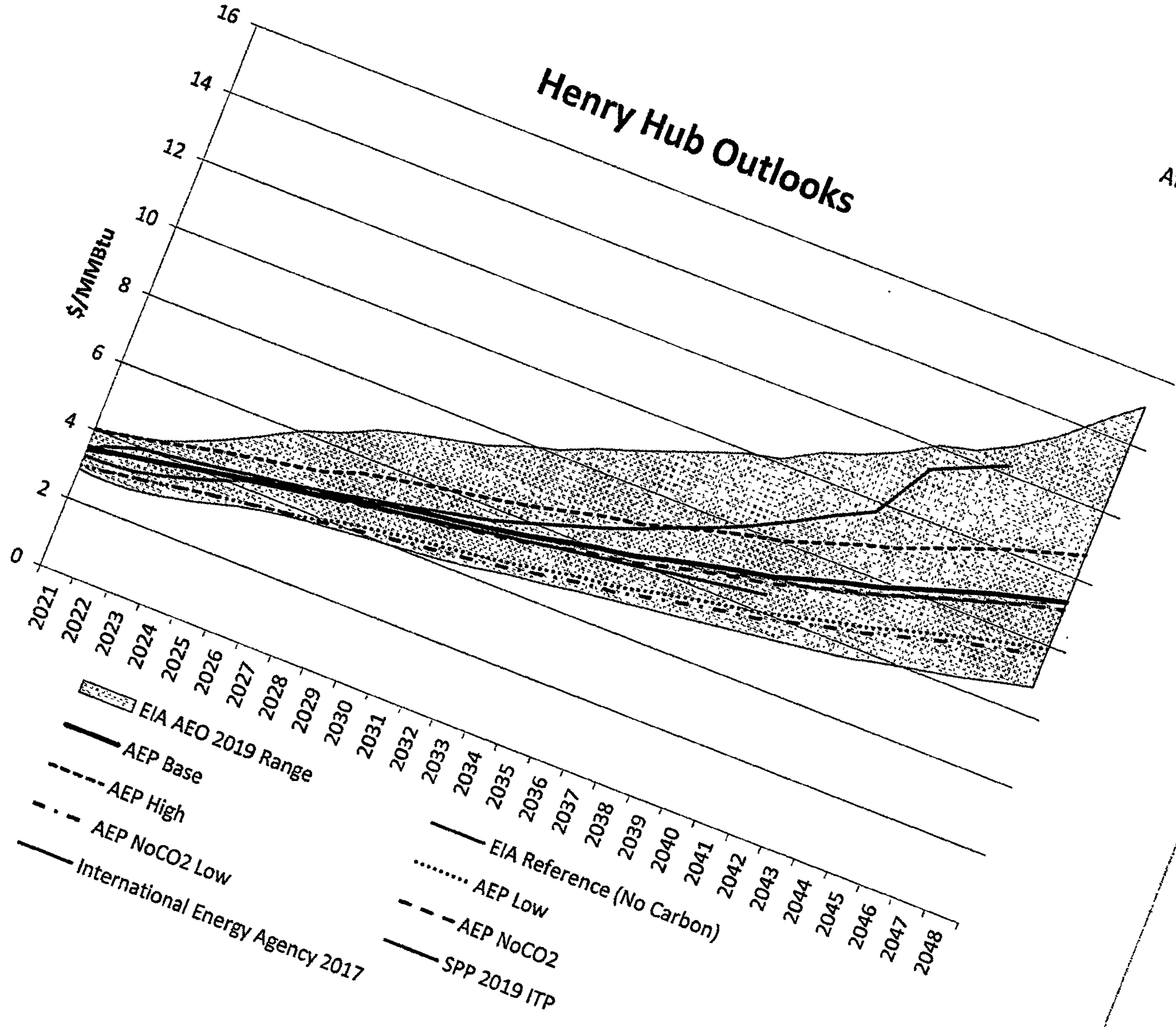
The chart of natural gas price forecasts (Bletzacker Direct, Figure 4, page 12) reflects the same ABB-developed forecasts [used/contained] in the SPP 2019 Integrated Transmission Plan and referred to in Pfeifenberger Direct Testimony, page 8. Tabular values can be found in OPUC_2_10_Attachment_1.

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

Sponsored By: Karl R. Bletzacker — Title: Dir Fundamental Analysis
Sponsored by: Johannes P. Pfeifenberger — Title: Principal, the Brattle Group

	SPP	IEA	EIA		
Year	SPP 2019 ITP	International Energy Agency 2017	EIA Reference (No Carbon)	EIA High	EIA Low
2019		3.10	3.10	3.48	2.90
2020	3.14	3.30	3.25	3.89	2.90
2021	3.68	3.50	3.24	4.10	2.81
2022	3.98	3.70	3.33	4.27	2.82
2023	4.10	3.90	3.56	4.60	2.97
2024	4.25	4.10	3.84	5.02	3.19
2025	4.40	4.30	4.20	5.53	3.47
2026	4.54	4.45	4.39	6.06	3.66
2027	4.70	4.59	4.52	6.38	3.79
2028	4.88	4.74	4.72	6.84	3.88
2029	5.07	4.89	4.84	7.11	3.97
2030	5.26	5.03	5.00	7.32	4.05
2031	5.48	5.18	5.09	7.53	4.15
2032	5.68	5.33	5.38	7.89	4.29
2033	5.97	5.47	5.58	8.14	4.45
2034	6.28	5.62	5.77	8.56	4.56
2035	6.58	5.77	5.95	8.89	4.71
2036	6.93	5.91	6.20	9.24	4.83
2037	7.34	6.06	6.37	9.59	4.95
2038	7.72	6.21	6.53	9.93	5.07
2039	8.16	6.35	6.71	10.16	5.20
2040	8.67	6.50	6.96	10.72	5.33
2041	9.24		7.10	11.05	5.44
2042	9.72		7.33	11.50	5.58
2043	11.36		7.61	12.08	5.72
2044	11.79		7.93	12.31	5.95
2045	12.24		8.25	12.81	6.13
2046			8.54	13.45	6.32
2047			8.88	14.29	6.55
2048			9.35	15.13	6.78

	AEP				
EIA AEO 2019 Range	AEP Base	AEP High	AEP Low	AEP NoCO2	AEP NoCO2 Low
0.58	3.21	3.69	2.73	3.21	2.73
0.99	3.44	3.95	2.92	3.44	2.92
1.29	3.54	4.08	3.01	3.54	3.01
1.44	3.71	4.27	3.16	3.71	3.16
1.63	3.89	4.48	3.31	3.89	3.31
1.83	4.08	4.70	3.47	4.08	3.47
2.06	4.24	4.88	3.60	4.24	3.60
2.41	4.40	5.06	3.74	4.40	3.74
2.59	4.55	5.23	3.86	4.55	3.86
2.96	4.84	5.57	4.12	4.69	3.98
3.14	5.01	5.76	4.26	4.85	4.12
3.27	5.17	5.95	4.40	5.01	4.26
3.38	5.30	6.10	4.51	5.14	4.37
3.60	5.45	6.27	4.64	5.28	4.49
3.69	5.62	6.46	4.78	5.44	4.63
3.99	5.82	6.69	4.95	5.64	4.80
4.18	6.02	6.92	5.12	5.84	4.97
4.41	6.14	7.06	5.22	5.96	5.07
4.64	6.39	7.35	5.43	6.21	5.28
4.86	6.64	7.63	5.64	6.45	5.48
4.96	6.84	7.87	5.82	6.65	5.65
5.39	7.02	8.07	5.97	6.82	5.80
5.61	7.32	8.42	6.22	7.12	6.05
5.92	7.61	8.75	6.47	7.40	6.29
6.35	7.84	9.02	6.67	7.64	6.49
6.37	8.18	9.41	6.95	7.97	6.77
6.68	8.50	9.77	7.22	8.28	7.04
7.13	8.81	10.12	7.48	8.59	7.30
7.74	9.05	10.41	7.69	8.83	7.51
8.35	9.32	10.72	7.92	9.09	7.73


Henry Hub Outlooks
$/MMBtu
0
2
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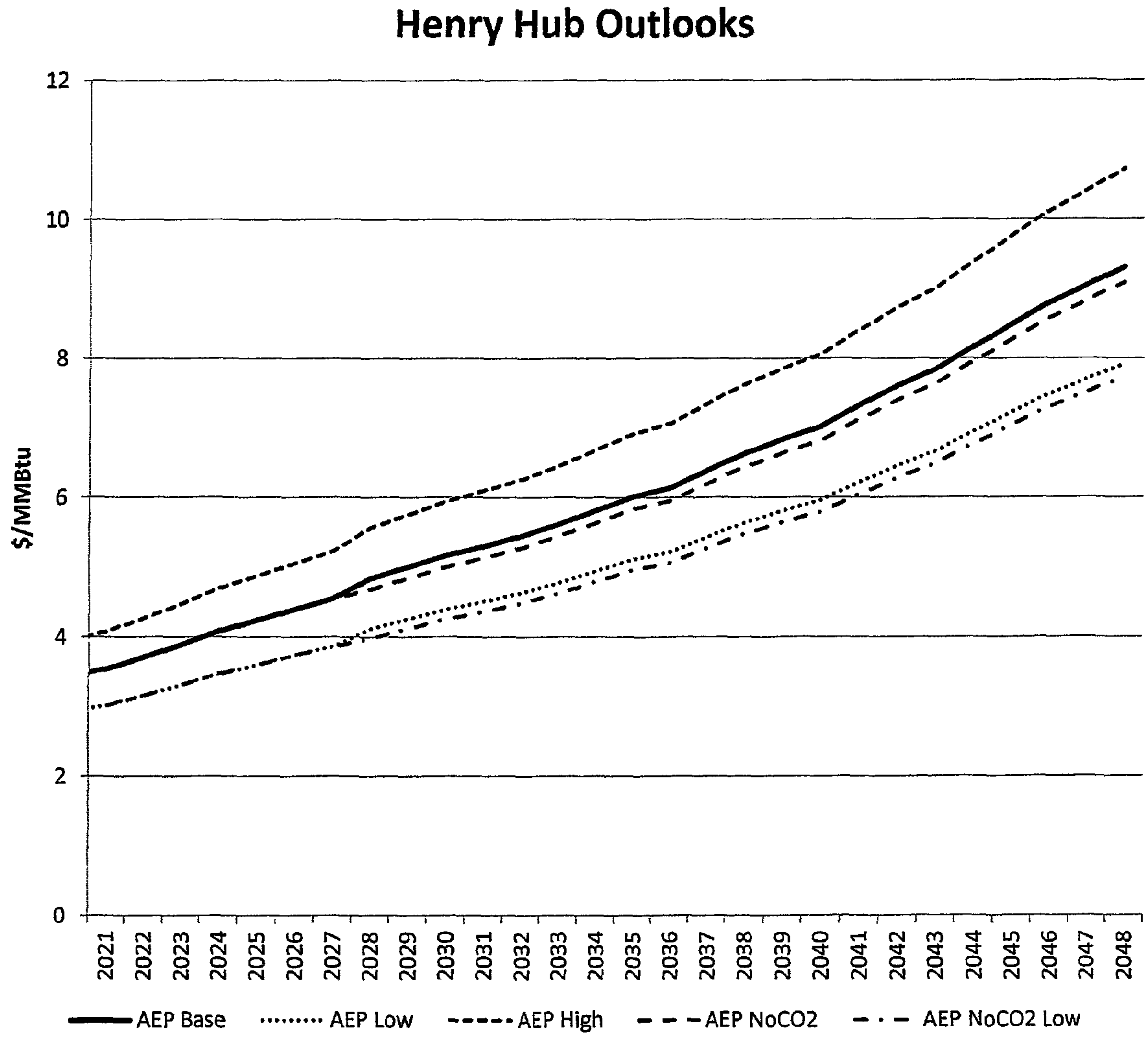
EIA AEO 2019 Range
AEP Base
AEP High
AEP NoCO2 Low
International Energy Agency 2017
EIA Reference (No Carbon)
AEP Low
AEP NoCO2
SPP 2019 ITP


Henry Hub Outlooks
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10
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$/MMBtu
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2047
2048
AEP Base
AEP Low
AEP High
AEP NoCO2
AEP NoCO2 Low

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

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

Question No. 2-11:

Refer to the direct testimony of Johannes Pfeifenberger at page 26, Table 3. Please provide the results in the format used in Table 3 if congestion costs and gen-tie costs were weighted 25% / 75% (the opposite of Criterion 5).

Response No. 2-11:

See the additional Criterion "OPUC 2-11" column in OPUC 2-11 Attachment 1, which shows the ranked cost of bids if congestion costs and gen-tie costs were weighted by 25% and 75%, respectively, and used in conjunction with the Project Costs.

As shown, under this criterion, the Company's selection of Traverse, Maverick, and Sundance remain the three lowest-cost bids in that order, indicating that the Company's selections are robust across a wide range of criteria, including this requested criterion.

As also shown, based on the requested criterion, the lowest cost 1,500 MW portfolio based on Criterion 1 and Criterion 2, would be 28.1% and 38.3% more expensive than the Selected Wind Facilities' delivered cost.

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

Sponsored by: Johannes P. Pfeifenberger — Title: Principal, The Brattle Group

Assessment of Wind Facilities Selection with an additional "25% Congestion/75% Gen-Tie" Selection Criterion

Criterion 1: Project Cost Only		Criterion 2: Project Cost + Congestion		Criterion 3: Project Cost + Gen-Tie		Criterion 4: Project Cost + 50% Congestion + 50% Gen-Tie		Criterion 5: Project Cost + 75% Congestion + 25% Gen-Tie		Criterion OPUC 2-11: Project Cost + 25% Congestion + 75% Gen-Tie	
Bid Number	% of Lowest Cost	Bid Number	% of Lowest Cost	Bid Number	% of Lowest Cost	Bid Number	% of Lowest Cost	Bid Number	% of Lowest Cost	Bid Number	% of Lowest Cost
2	100%	3*	100%	Traverse (21)	100%	Traverse (21)	100%	Traverse (21)	100%	Traverse (21)	100%
Sundance (17)	121%	2	114%	Maverick (15)	106%	Maverick (15)	102%	Maverick (15)	100%	Maverick (15)	104%
12	126%	1	117%	6	107%	Sundance (17)	106%	Sundance (17)	101%	Sundance (17)	111%
4	129%	Sundance (17)	119%	Sundance (17)	116%	12	113%	1	105%	6	115%
Maverick (15)	132%	Maverick (15)	121%	12	121%	1	115%	12	109%	12	117%
Traverse (21)	133%	Traverse (21)	124%	1	139%	6	121%	4	117%	1	127%
1	133%	4	130%	30	147%	4	129%	2	118%	30	139%
32	135%	33*	130%	4	156%	30	133%	30	126%	4	142%
3*	135%	12	131%	31	180%	2	145%	6	128%	31	168%
29*	160%	34*	141%	2	204%	31	157%	32	138%	2	173%
30	163%	32	146%	32	207%	32	160%	31	146%	32	182%
31	184%	30	149%								
33*	185%	29*	155%								
34*	189%	6	166%								
6	189%	31	168%								
Capacity-Wtd Average of Lowest Costs 1,500 MW	100.0%	Capacity-Wtd Average of Lowest Costs 1,500 MW	100.0%	Capacity-Wtd Average of Lowest Costs 1,500 MW	100.0%	Capacity-Wtd Average of Lowest Costs 1,500 MW	100.0%	Capacity-Wtd Average of Lowest Costs 1,500 MW	100.0%	Capacity-Wtd Average of Lowest Costs 1,500 MW	100.0%
Capacity-Wtd Average of Selected Wind Facilities	106.5%	Capacity-Wtd Average of Selected Wind Facilities	104.0%	Capacity-Wtd Average of Selected Wind Facilities	101.1%	Capacity-Wtd Average of Selected Wind Facilities	100.0%	Capacity-Wtd Average of Selected Wind Facilities	100.0%	Capacity-Wtd Average of Selected Wind Facilities	100.0%
				Capacity-Wtd Average of Lowest Cost 1,500 MW in Criterion 1	140.2%	Capacity-Wtd Average of Lowest Cost 1,500 MW in Criterion 1	117.9%	Capacity-Wtd Average of Lowest Cost 1,500 MW in Criterion 1	108.2%	Capacity-Wtd Average of Lowest Cost 1,500 MW in Criterion 1	128.1%
				Capacity-Wtd Average of Lowest Cost 1,500 MW in Criterion 2	155.3%	Capacity-Wtd Average of Lowest Cost 1,500 MW in Criterion 2	123.7%	Capacity-Wtd Average of Lowest Cost 1,500 MW in Criterion 2	109.7%	Capacity-Wtd Average of Lowest Cost 1,500 MW in Criterion 2	138.3%

Notes:

*Unit was disqualified from Company's evaluation based on deliverability.

Named units represent the Company's Selected Wind Facilities.

Lowest Cost 1,500 MW in each ranking are highlighted blue.

PUC DOCKET NO. 49737

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' FIRST REQUEST FOR INFORMATION

Question No. TIEC-1-5:

How often does AEP create its Fundamentals Forecast?

Response No. TIEC-1-5:

AEPSC has no rigid schedule for the creation of new Fundamentals Forecasts. However, as evidenced in TIEC 1-9, nine Fundamentals Forecasts have been completed from 2010 to 2019. The Fundamentals Analysis team continuously evaluates material changes in the long-term energy market drivers for indications that a new Fundamentals Forecast is warranted.

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 TEXAS INDUSTRIAL ENERGY CONSUMERS' NINTH REQUEST FOR INFORMATION

Question No. TIEC 9-3:

Has SWEPCO/AEP analyzed the probability of a carbon tax or similar carbon burden being enacted during the 2021-2051 period? If so, please provide any such analyses.

Response No. TIEC 9-3:

Yes. The Fundamentals Forecast employed a CO_2 dispatch burden on all existing fossil fuel-fired generating units that escalates 3.5% per annum from $15 per metric ton commencing in 2028. This CO_2 dispatch burden was the same across the Base, High and Low Cases and is a proxy for other pathways CO_2 mitigation may take in addition to any regulation to impose fees on the combustion of carbon-based fuels. It is the assessment of Company experts that the likelihood of any federal climate legislation is very low over the next two years. With 2021-2023 as the earliest reasonable date for a climate proposal to pass through committee, reach the floor and be approved for eventual passage, there will be an implementation period of approximately five years (as seen in previous climate proposals). Thus, 2028 is the earliest reasonable projection as to when such legislation could become effective. The Fundamentals Forecast is not merely concerned with the current status of regulations and other current conditions that affect prices, but instead must also reflect reasonable expectations regarding future conditions that affect prices. As such, the carbon price proxy used for fundamentals forecasting is a reasonable assessment of future costs based on the current prospects for carbon regulations or other proxies for CO_2 mitigation costs and potential changes thereto. The Company has also provided analyses with an assumption of no carbon burden.

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 TEXAS INDUSTRIAL ENERGY CONSUMERS' NINTH REQUEST FOR INFORMATION

Question No. TIEC 9-4:

What is SWEPCO/AEP's position regarding the possibility of a carbon tax or similar carbon burden being enacted during the 2021-2051 period?

a. Who are the individual(s) at SWEPCO/AEP that are responsible for developing that position?

b. Please state the probability that SWEPCO/AEP believes is reasonable to assign to the possibility of a carbon tax or similar carbon burden being enacted during the 2021-2051 period.

Response No. TIEC 9-4:

Please refer to the Company's response to TIEC 9-3.

a. Collaborative carbon pricing proxy development primarily involves the Vice President of Environmental Services, the Director of Air Quality Services, the Deputy General Counsel (Environmental), and the Director of Fundamentals Analysis.

b. The Company characterizes the probability of a carbon tax or similar carbon burden being enacted during the 2021-2051 period as "highly likely."

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 EAST TEXAS ELECTRIC COOPERATIVE, INC. AND NORTHEAST TEXAS ELECTRIC COOPERATIVE, INC.'S FIRST REQUEST FOR INFORMATION

Question No. 1-32:

Please provide all documents relating to the Company's analysis or consideration of a dedicated transmission line that connects one or more of the Selected Wind Facilities to a load center (Gen-Tie). Without limiting the generality of the foregoing, please provide information related to the estimated cost, routing plan or options, project timeline, voltage level, and length of the transmission line.

Response No. 1-32:

Please see ETEC_NTEC 1-32 Attachment 1(provided electronically on the PUC Interchange), which is the workpaper of Company witness Ali. This workpaper was provided at the time of the filing and is available on the PUCT interchange in this docket as Item #11. The Company's estimate is based on a 345 kV line.

The Company 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.

Prepared By: Anita A. Sharma — Title: Engineer Staff

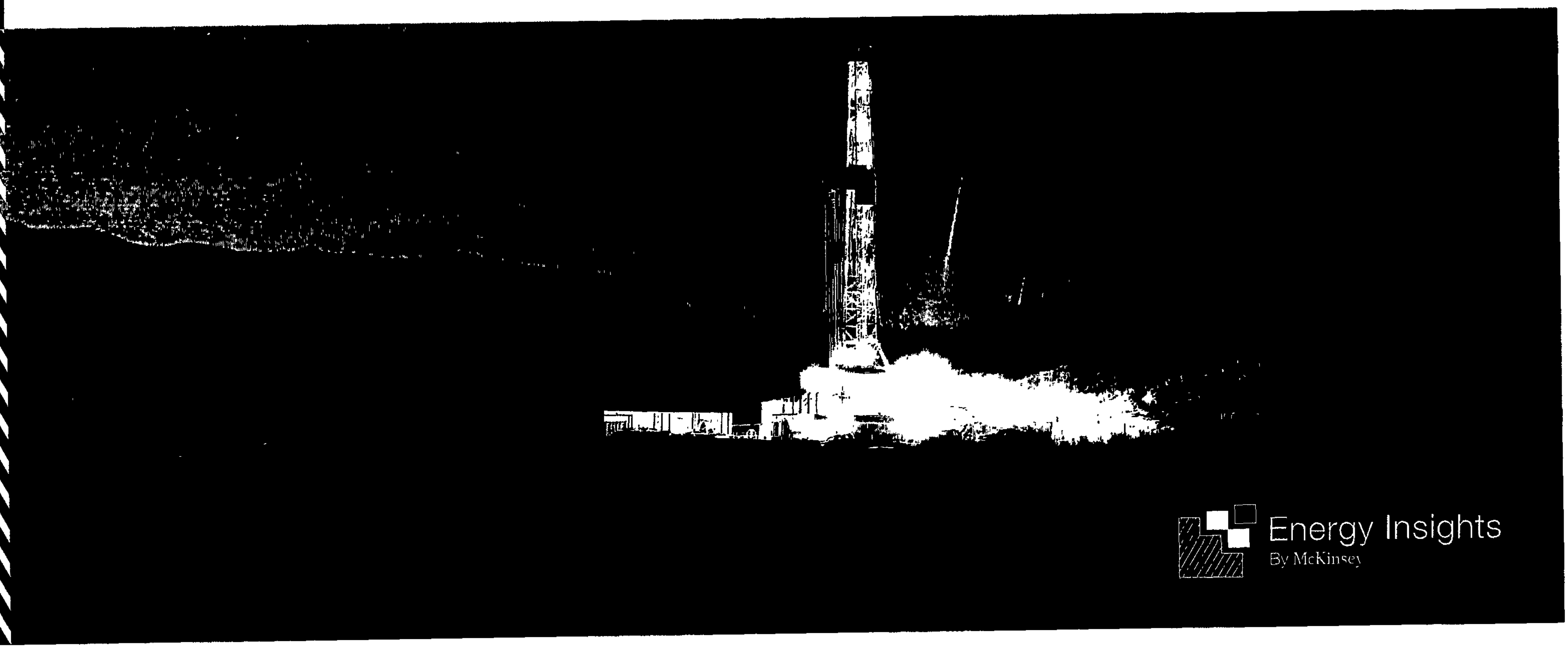
Sponsored By: Kamran Ali — Title: Mng Dir Trans Planning

PSO/SWEPCO RFP - Gen Tie Cost Estimate

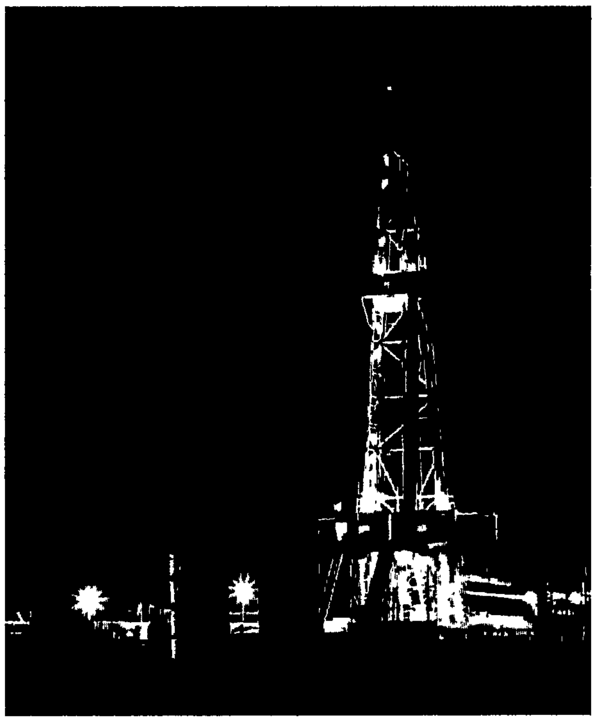
Gen-Tie		**Full Scope**	**Traverse**	**Maverick**	**Sundance**
RSS Hub - Traverse (101 miles)	Line	$223,000,000	$198,202,400	$24,797,600	
Traverse - Maverick (34 miles single ckt 2-795)	Line	$47,265,860		$47,265,860	
Maverick - Sundance (49 miles single ckt 2-795)	Line	$68,118,445			$68,118,445
RSS Cap Bank	Station	$6,750,000	$6,750,000		
RSS Hub	Station	$20,500,000	$20,500,000		
Traverse Station	Station	$23,000,000	$23,000,000		
Maverick/Sundance Station	Station	$17,500,000		$8,750,000	$8,750,000
Gen-Tie Cost		**$406,134,305**	**$248,452,400**	**$80,813,460**	**$76,868,445**
AFUDC @ 9.263%		$37,620,221	$23,014,146	$7,485,751	$7,120,324
Total 2021 Cost		$443,754,526	$271,466,546	$88,299,211	$83,988,769

North American Gas Outlook to 2030

H1 2019



Executive summary



Demand

- US and Canadian LNG exports account for ~60% of demand growth and will reach ~20 bcfd by 2030
- Coal retirements will provide upside to gas demand in the near term but renewables will start to displace gas post-2025, although total demand continues to grow

Supply

- Appalachia will increase production to ~55 bcfd and supply ~40% of the North American market by 2030
- Associated gas, primarily from the Permian, is expected to increase production by ~12 bcfd and supply 25% of the N. American market by 2030

Gas flows and price volatility

- Appalachia expected to displace WCSB & Rockies in the Midwest and serve the southern Mid-Atlantic
- Permian expected to limit Appalachian flows south and will help meet USGC demand
- Pipe build, especially from Appalachia, expected to continue to decrease volatility

Price

- Shale has unlocked enough supply to keep prices ~$2.75/mmbtu over the longer term, with likely bias to the downside

North America gas demand expected to grow at a modest ~2% p.a., driven by strong exports, despite peak demand for power in sight

Outlook

Mexico export 2.7 bcfd of demand growth, new takeaway pipelines, less LNG imports, and flat local production results in higher US exports to Mexico

LNG export US and Canadian LNG projects are competitive, even in a long global LNG market, leading to utilization rate being maintained above 70%

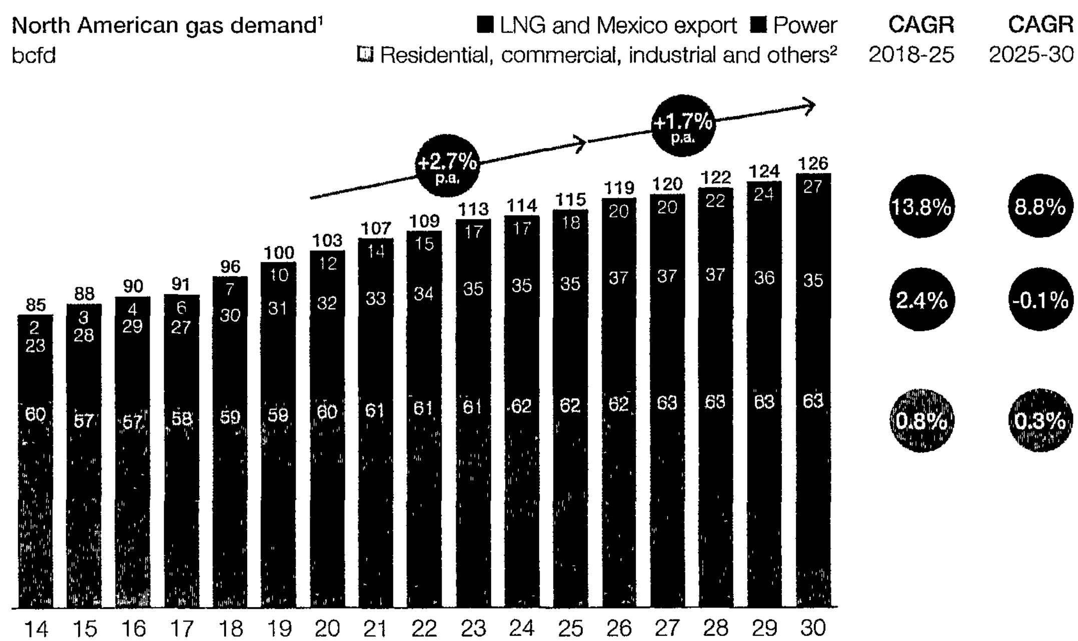
Power Expected to grow another 5 bcfd as additional ~70 GW of gas capacity comes online by 2025, but will flatten from 2026 as it faces strong competition from renewables

Residential and commercial Expected to stay flat as floor space growth is mostly offset by continued efficiency improvements

Industrial Growth will be driven by increasing use of gas as a feedstock in producing methanol and ammonia

Pipe, plant and lease fuel Use of gas at fueling compressor stations and lease sites is expected to grow slightly as production grows

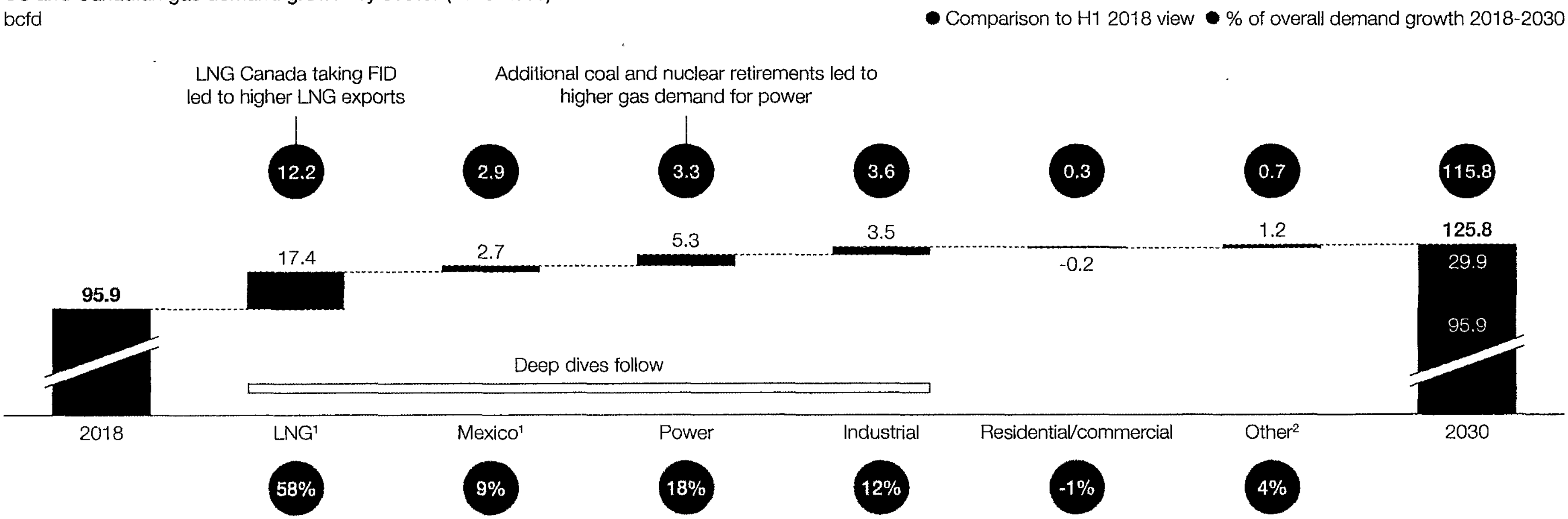
North American gas demand[1]
bcfd



1 Dry gas consumption in US and Canada 2 Includes pipe, plant, lease, and natural gas vehicles (NGVs)
Source: McKinsey Energy Insights Global Energy Perspective Model; EIA; NEB

~70% of North American gas demand growth is linked to global drivers, mostly through LNG exports

US and Canadian gas demand growth by sector (2018-2030)
bcfd



1 Direct export driven 2 Includes pipe, plant, lease, and natural gas vehicles (NGVs)
Source: McKinsey Energy Insights GEP Model; EIA; NEB

North American LNG exports will grow quickly until 2023 then plateau until a second wave of capacity comes online from 2025

Short term (to 2021)

- Global LNG supply overcapacity puts pressure on US liquefaction capacity utilization, which has among the highest marginal costs. Balancing out global LNG overcapacity is equivalent to an average US LNG capacity utilization rate of 70% from 2019-21
- Construction delays primarily at Cameron and Freeport prevent new capacity from coming online until the global LNG market has recovered in ~2021

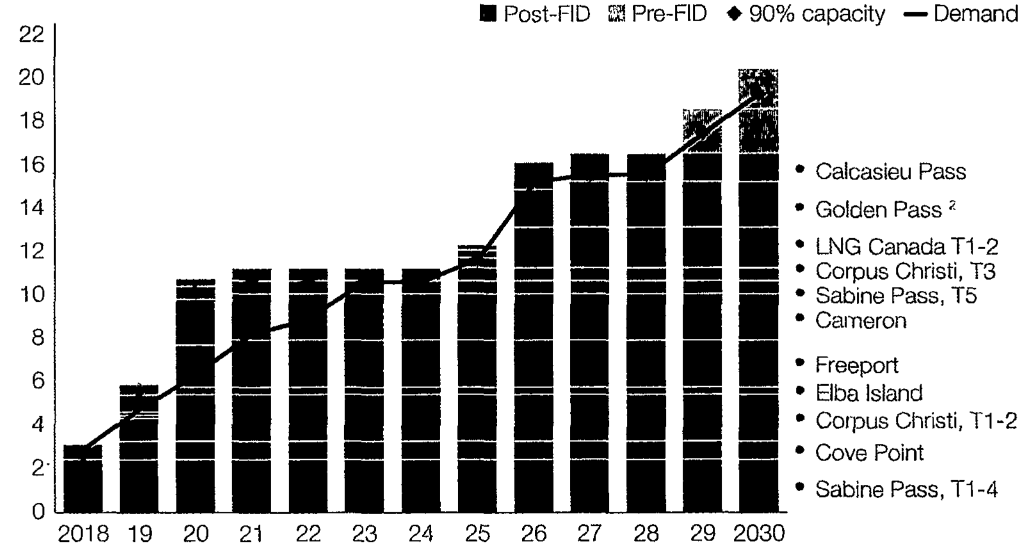
Mid term (2021-24)

- Slowdown in North American projects is expected from 2021-24 as new international LNG supply comes online, primarily from Qatar
- US LNG exports are sensitive to global gas demand, as the marginal supplier to the Europe and Asia

Long term (2025-30)

- Post FID plants (LNG Canada, Golden Pass and Calcasieu Pass) come online in 2025[1]
- From 2028-29, there will likely be room for 2-3 most cost-advantaged LNG projects from North America to fill the global LNG supply gap

North American LNG capacity and demand outlook
bcfd



1 Assumes delays to start in mid-2025
2 Assumes delays to start in mid-2025
Source: McKinsey Energy Insights; team analysis; press release

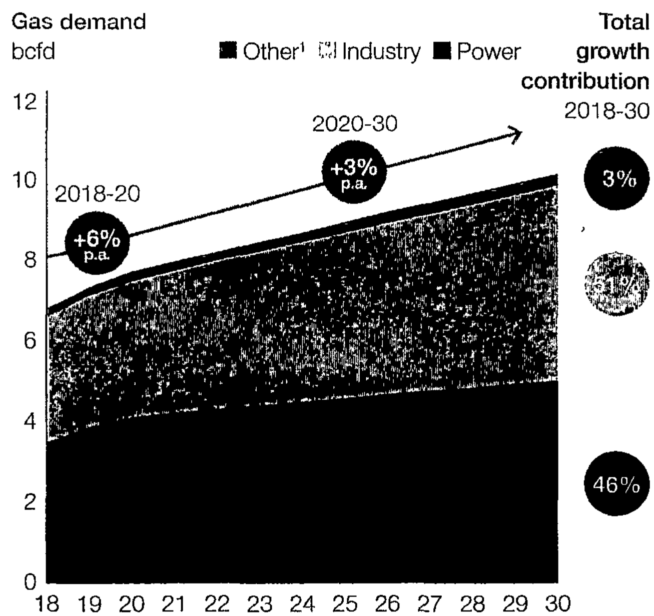
Mexico's dependence on US gas imports increases as gas demand grows and domestic production declines

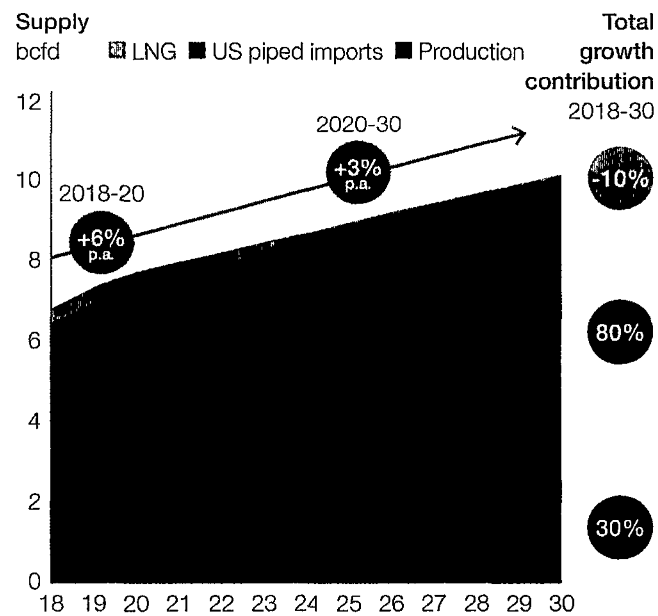
Gas demand

- Gas demand will increase due to growth in the industrial and power sectors
  - Nearly 18 GW of new gas fired CCGTs expected to be added by 2020 effectively removing fuel oil from the power mix
  - Industrial demand growth is driven by export oriented manufacturing as well as methanol/fertilizer projects

Gas supply

- In the long term, growth of US exports to Mexico will slow due to an increase in Mexico's domestic production
- LNG is being displaced by US imports, except for a small volume to prepare for an emergency



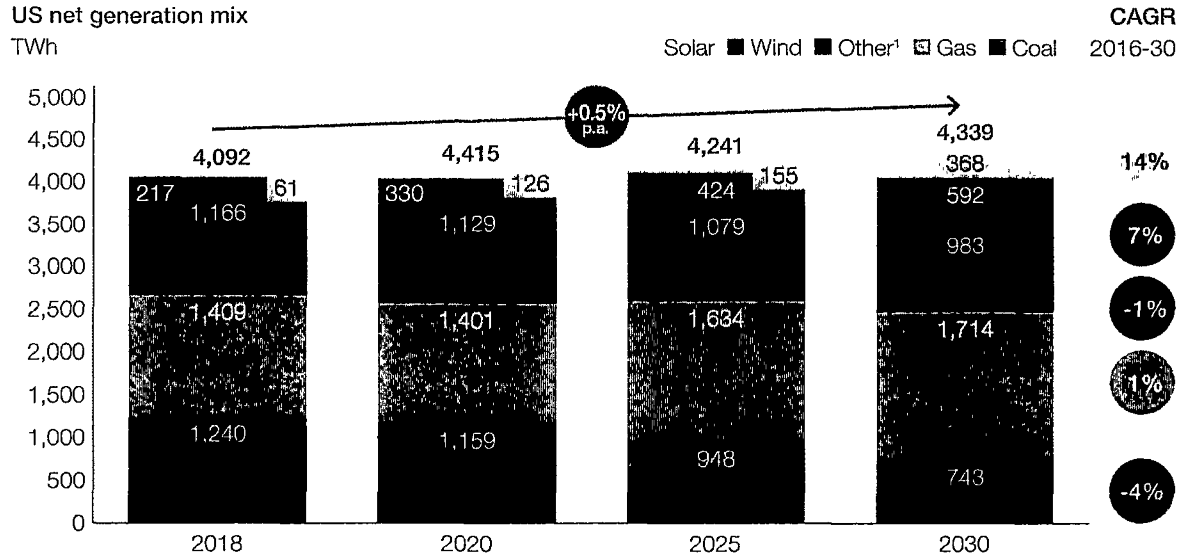


1 For example: residential, services and NGVs
Source: McKinsey Energy Insights; CRE; CFE; SENER

Gas continues to gain market share from coal, despite facing more competition from renewables post-2020

Key implications

- As coal retires, gas generation increases to meet evening and night time loads
- Gas demand for power generation continues to grow until ~2025, but as high-efficiency CCGTs replace existing low-efficiency OCGTs/CCGTs, gas consumption decreases despite growing generation
- Falling power storage costs are enabling deployment of renewables at scale over a 10-20 year timeframe, enabling solar and storage to replace gas for peaker plants



	2018	2020	2025	2030	CAGR 2016-30
Gas demand bcfd	29	32	35	35	1.4%

1 Other includes hydro, nuclear, oil, and coal co-fired with biomass, as well as biomass, waste, and geothermal
Source: McKinsey Energy Insights Global Power Model; EIA

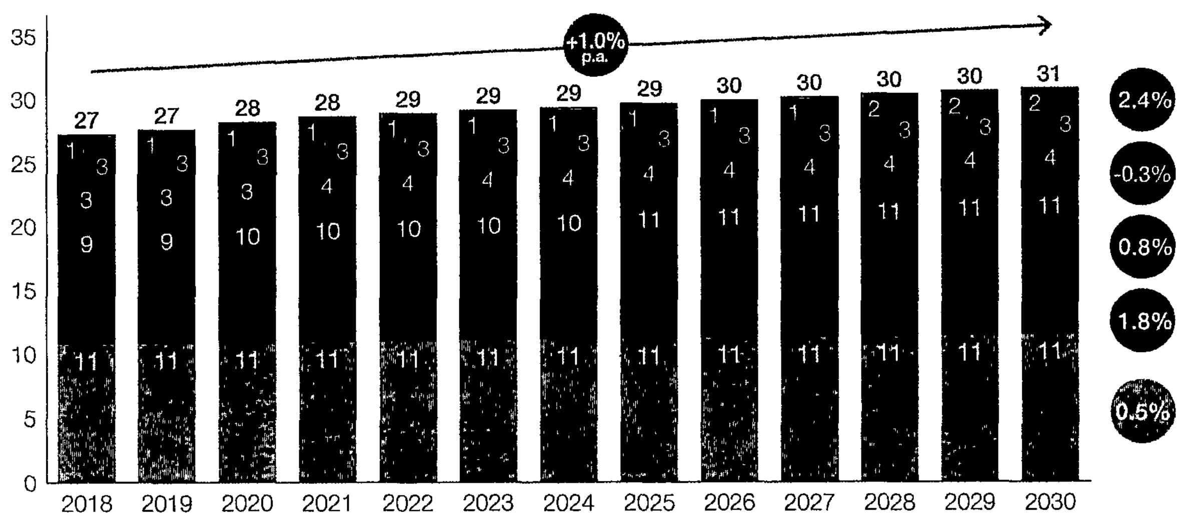
Industrial gas demand growth is limited except for chemicals

Key drivers

- Industrial consumption will grow slowly over the next 10 years, with chemicals driving 60% of the growth, as the use of gas as a feedstock in chemicals increases, particularly in ammonia and methanol
- Demand for gas in steel and iron will grow relatively quickly due to increasing capacity of direct reduced iron (DRI) facilities and increasing local steel utilization driven by tariffs on imported steel

Industrial demand by sub-sector
bcfd ■ Iron and steel ■ Refining ■ Mining/O&G extraction[1] ■ Chemicals/petrochemicals □ Other[2]

CAGR 2018-30



1 Includes oil sands 2 Agriculture, construction, metal, food processing, textile and leather, plastics, wood/wood products, non-specified energy/ commercial/transformation, and paper
Source: McKinsey Energy Insights Global Energy Perspective; McKinsey Energy Insights Global Liquids Supply Model; EIA; CERI natural gas market review 2016

The Appalachian and Permian basins will supply ~53% of the North American market by 2030, and represent 83% of the growth

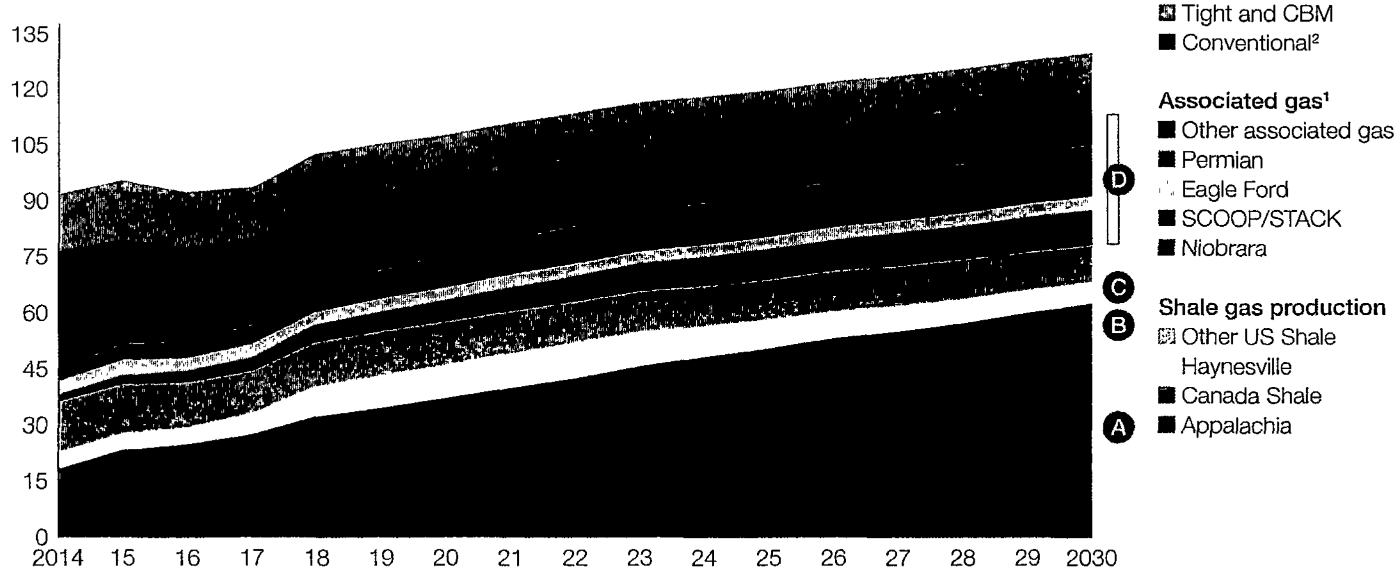
A Appalachia
Production grows at 6% p.a. as the basin is debottlenecked in 2018-19

B Western Canadian Sedimentary Basin (WCSB)
Steady growth in Montney production with possible upside with Western Canadian LNG

C Haynesville
Renewed interest due to close proximity to LNG export terminals and attractive well economics

D Associated gas/Permian
Permian production will increase by ~7.2 bcfd from 2018 to 2030

Total projected natural gas production
bcfd



1 Includes conventional and unconventional 2 Includes conventional gas basins, Alaska, and offshore
Source: EIA; McKinsey Energy Insights North American Supply Model

In 2025, growing Appalachia and Permian production will push Canadian and Rockies gas out of Midwest and Eastern markets[1]

Two dynamics are fundamentally changing how gas moves in North America in 2025:

Growing production from Appalachia, SCOOP/STACK and the Permian

- An increase of 14 bcfd production from Appalachia will back out Canadian and midcontinent gas
- Growing associated gas production in the Permian and SCOOP/STACK areas will require additional midstream build-out

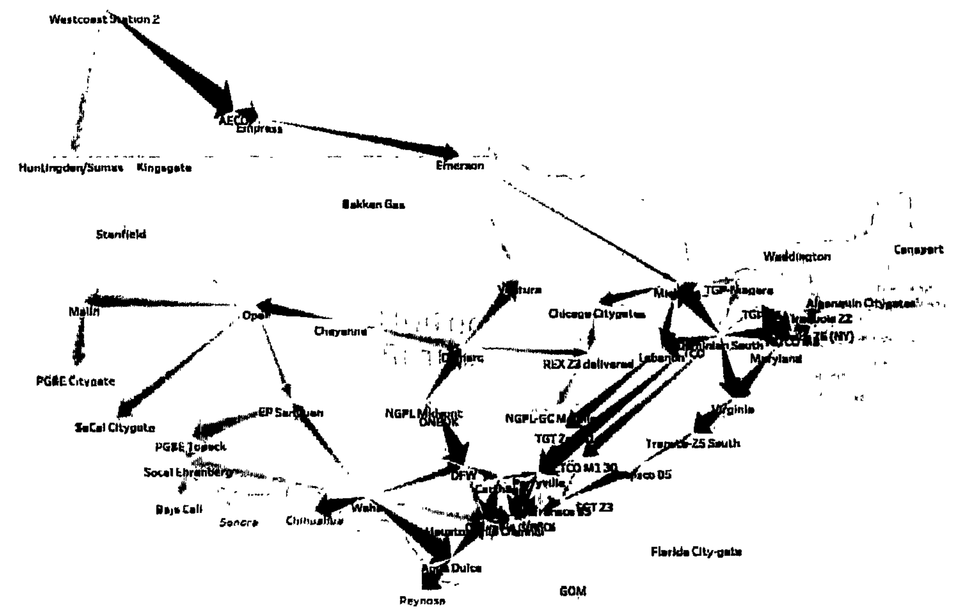
Rising demand in US Gulf Coast market due to LNG and Mexico exports

- Increases of ~17 bcfd demand by 2030 will require new pipes to connect Northeast and west Texas basins to the Gulf Coast
- Increasing competition between WCSB and Rockies in the western market will keep western Canadian prices low

Gas flow in 2025[1]

Flow change compared to 2018, mmcfd

-2,000 +2,000



1 Average winter flow in 2025 with arrows size proportional to 2025 flow volume

Source: EIA, McKinsey analysis

Supply and demand drivers sustain current North America gas prices in mid term but eventually lower gas prices in long term

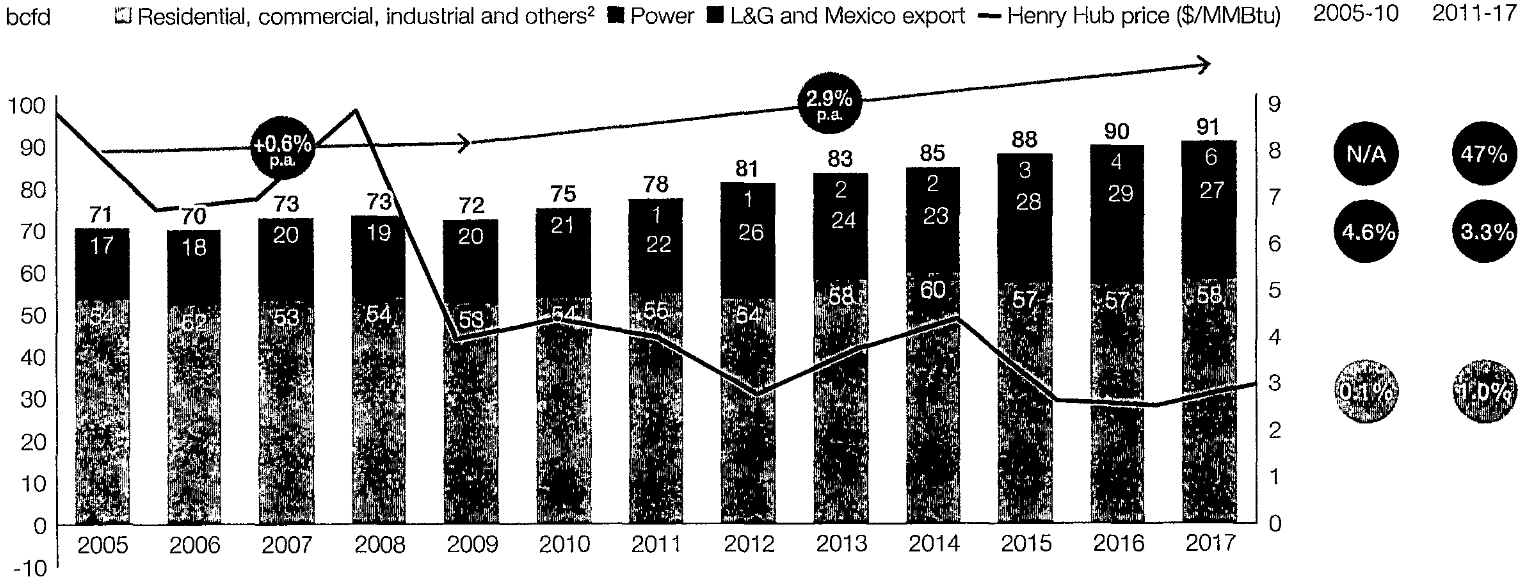
	Key factors	Potential impact on gas price and gas price setting mechanism	↓ Lowers price ↑ Boosts price
		Mid term (to 2025)	**Long term (post 2025)**
Demand	**Power**	↑ Coal retirements limit competition allowing regional gas prices to rise higher before gas generation becomes regionally uneconomic ↓ Continued decline of renewable costs leads to additional renewable generation	↓ Renewables displacing gas in the power sector, especially as power storage becomes increasingly economic
	LNG	↑ LNG exports can increase by ~2 bcfd due to underutilized liquefaction capacity	↑ Global LNG supply/demand expected to tighten, increasing US LNG plant utilization
	Mexico	↑ Pipe capacity additions, CCGT and industrial investments in Mexico will further boost Mexican consumption of US gas	↓ Falling solar costs and a rebound in indigenous production slow Mexican demand growth for US gas imports
Supply	**Appalachian supply**	↓ As more pipeline infrastructure comes online post 2019, inexpensive Appalachian supplies will continue to grow and limit price fly-up potential	↓ The second wave of new pipeline capacity addition in the Appalachia, if realized, would lower gas prices nationally
	Associated gas supply	↓ At $60/bbl, "zero cost" associated gas production could increase by ~8 bcfd by 2025, most of which is expected from the Permian	↓ Associated gas production continue to increase, making up ~27% of US gas production by 2030
	Drilling costs	↓ Drilling efficiency increases and new completion technology will lower well and service costs	↓ Drilling efficiency increases and new completion technology will lower well and service costs
	Net price impact	↓↓ **$2.50 to $2.75 mmbtu**	↓↓ **$2.25 to $2.75 mmbtu**

Source: EIA, McKinsey analysis

Gas demand in North America was flat until 2009; since then, it has grown at ~3% p.a. following a 70% drop in gas price

- Seasonal heating and power continue to drive the market, with power driving the most growth in gas demand since 2005, an increase of 10 bcfd
- North America has transitioned from being a LNG importer to an exporter
- Rapid growth rates in gas exports to Mexico have added 6 bcfd in gas demand

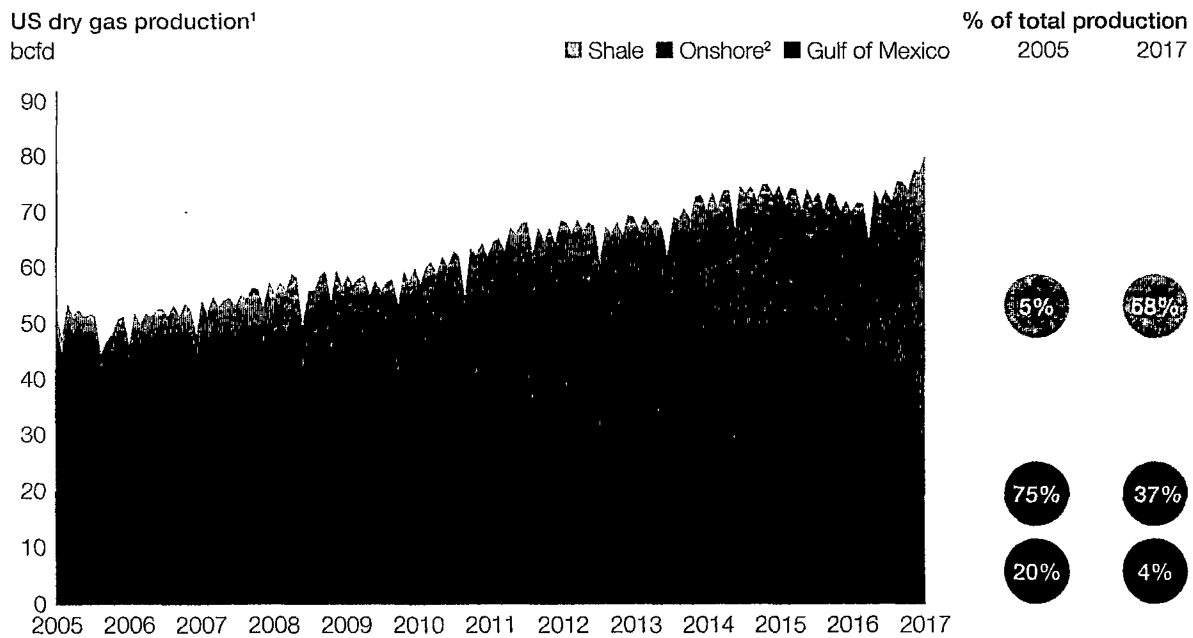
North American gas demand by sector[1] and Henry Hub price
bcfd



Note: individual numbers may not equal total due to rounding 1 Net of balancing items 2 Includes natural gas vehicles; and pipe, plant, and lease fuel, which is gas used for pipeline fuel, consumption at gas plants, lost during transportation, and for usage for compressors and equipment at lease sites
Source: EIA; NEB; NYMEX; McKinsey Energy Insights

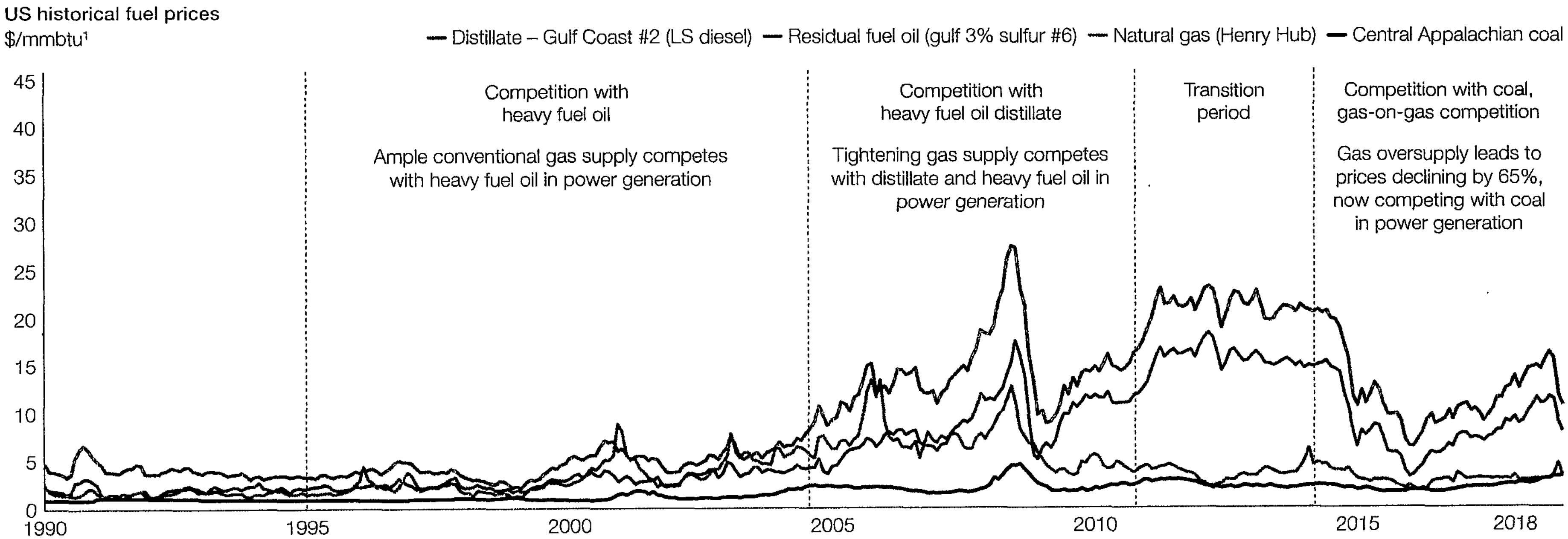
Gas supply shifted from conventional to unconventional; shale gas grew at 25% p.a., reshaping the North American gas supply outlook

- Shale exploded from virtually nothing to become the driving force of gas supply.
- Gas production has remained resilient despite low prices:
  - High grading of drilling programs
  - *Increasing* well design *intensity* in Marcellus
  - Improved rig productivity (e.g., pad drilling, drilling days)
  - Infrastructure de-bottlenecking, releasing choked wells
  - Strong contribution from associated gas of light tight oil plays



1 Total dry gas production taken from EIA natural gas dry gas production file 2 Includes Alaska
Source: SOURCE: Drilling Info; EIA; Energy Insights North American Supply Model; Baker Hughes

Shale gas boom has weakened gas prices into competition with coal in the power sector, with prices declining by ~65% post 2008



1 Converted at heat content of 6.02 for Gulf Coast RFO, 5.72 for Gulf Coast No.2, 25 MMBtu/ton for Central Appalachian Coal, and 24 MMBtu/ton for Illinois Basin Coal; SOx, NOx or CO_2 costs not included
Source: NYMEX; Bloomberg

Growing shale production in the Northeast has changed how gas flows in the United States over the last decade

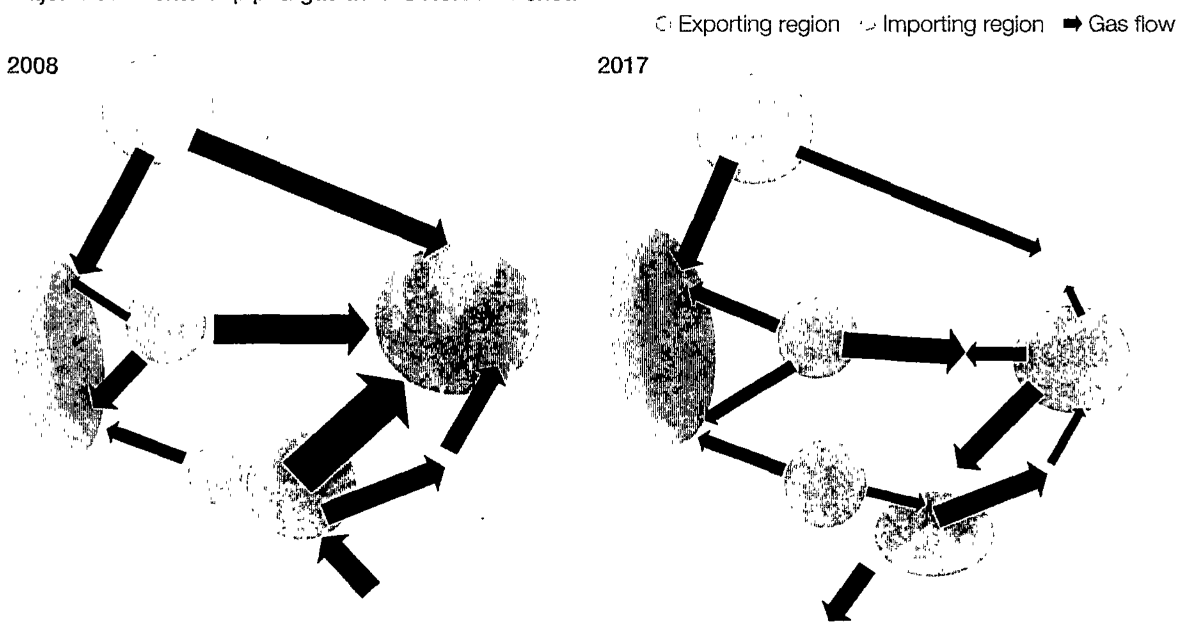
Growing shale production has changed the main supply areas

- In 2008, gas in NA was mainly supplied by three areas: the Gulf Coast (including Mid-Continent), Western Canada, and the Rockies
- In 2017, significant growth in unconventionals has made the Marcellus/Utica the largest gas producing area

Growing demand in the Gulf Coast states has since reversed the south to north flows of 2008

- TX and LA enjoyed the largest demand growth of a combined 1.9 bcfd due to growing power and industrial demand
- >2 bcfd of growth in export demand to Mexico over the past three years has reversed flow directions in South Texas, as gas now moves south through Agua Dulce

Major movements of piped gas across North America



SOURCE: McKinsey Energy Insights North America Gas Flow Basis Model; McKinsey Energy Insights North American Supply Model; EIA

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Energy Insights
By McKinsey

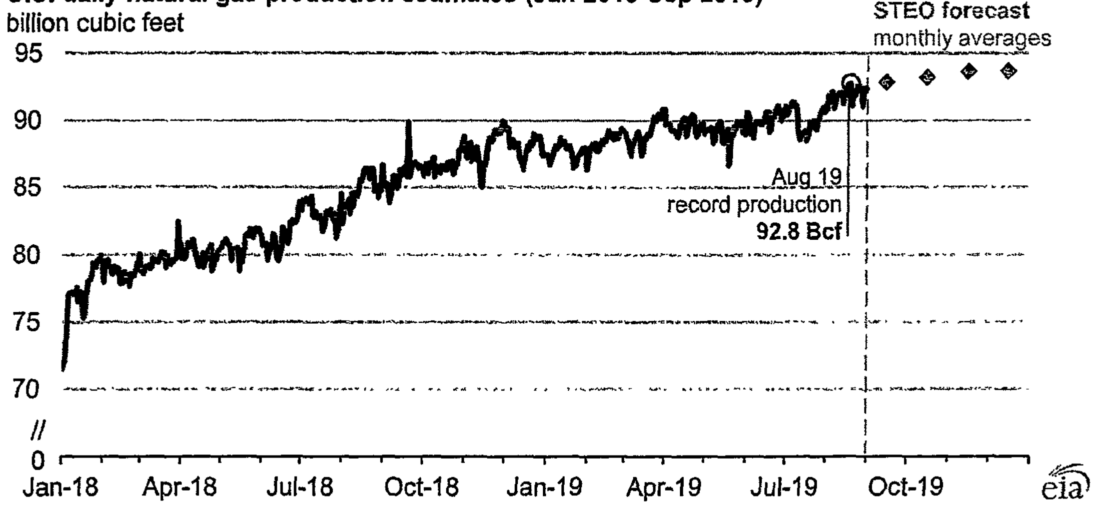
U.S. Energy Information Administration

Today in Energy

September 12, 2019

U.S. natural gas production reaches a new record despite low prices

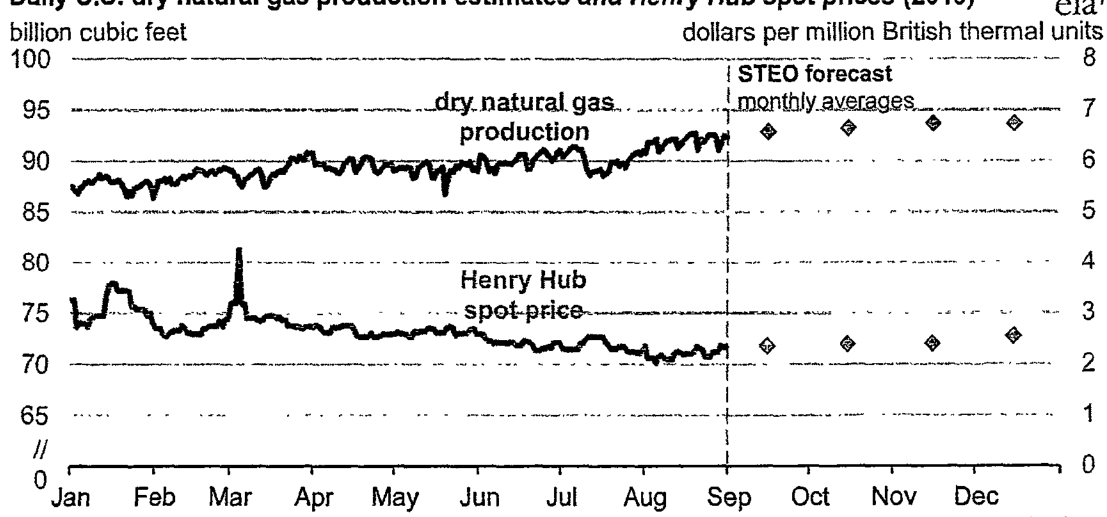
U.S. daily natural gas production estimates (Jan 2018-Sep 2019)



Source: U.S. Energy Information Administration, *Short-Term Energy Outlook*; IHS Markit

U.S. natural gas production continued to increase in August, setting a new daily production record of 92.8 billion cubic feet per day (Bcf/d) on August 19, 2019, according to estimates from IHS Markit. Natural gas production also set a new monthly record in August, averaging more than 91 Bcf/d for the first time. In the latest *Short-Term Energy Outlook* (STEO), released on September 10, 2019, the U.S. Energy Information Administration (EIA) forecasts dry natural gas production to average 93.4 Bcf/d from September through the end of the year. U.S. natural gas production increased by 7.1 Bcf/d (8%) between August 2018 and August 2019, led by production gains primarily in the Northeast.

Daily U.S. dry natural gas production estimates and Henry Hub spot prices (2019)



Source: U.S. Energy Information Administration, *Henry Hub daily price* and *Short-Term Energy Outlook*; IHS Markit

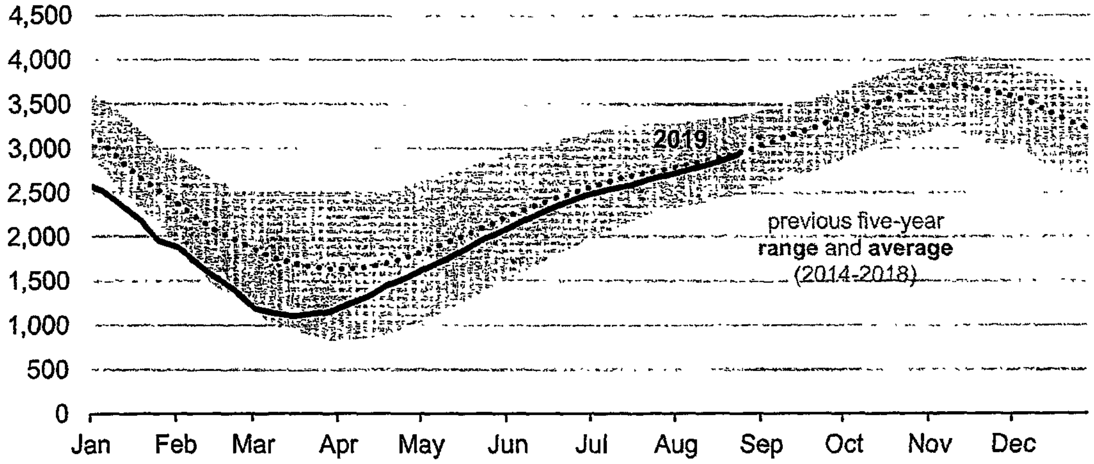
U.S. natural gas production has increased, even as natural gas prices have declined. Natural gas spot prices at the national price benchmark Henry Hub have been on a downward trend since early spring. Spot prices at other natural gas hubs across the country have continued to sell at discounts to Henry Hub.

Record growth in U.S. natural gas production continues to put downward pressure on prices. This summer, prices have continued to decline despite high levels of natural gas exports and increased consumption in the electric generation sector.

Henry Hub prices averaged $2.40 per million British thermal units (MMBtu) in June and $2.37/MMBtu in July—the lowest monthly averages for June and July since 1999—as growth in natural gas production continued to offset growth in consumption. In its September STEO, EIA forecasts Henry Hub prices to increase through the remainder of the year, ultimately averaging $2.55/MMBtu in December.

Natural gas storage has been absorbing a significant amount of the increase in U.S. production. Working natural gas inventories in the Lower 48 states began the injection season (April 1) about 30% lower than the previous five-year (2014–18) average level for that time of year. By the week ending August 30, 2019, working natural gas inventories were just 3% lower than the five-year average for that time of year. The net injection rate into storage during that time was equal to 11.9 Bcf/d, or about 30% more than the typical injection rate for that period, based on the average of the previous five years.

Lower 48 states working natural gas inventories (2014-2019)
billion cubic feet



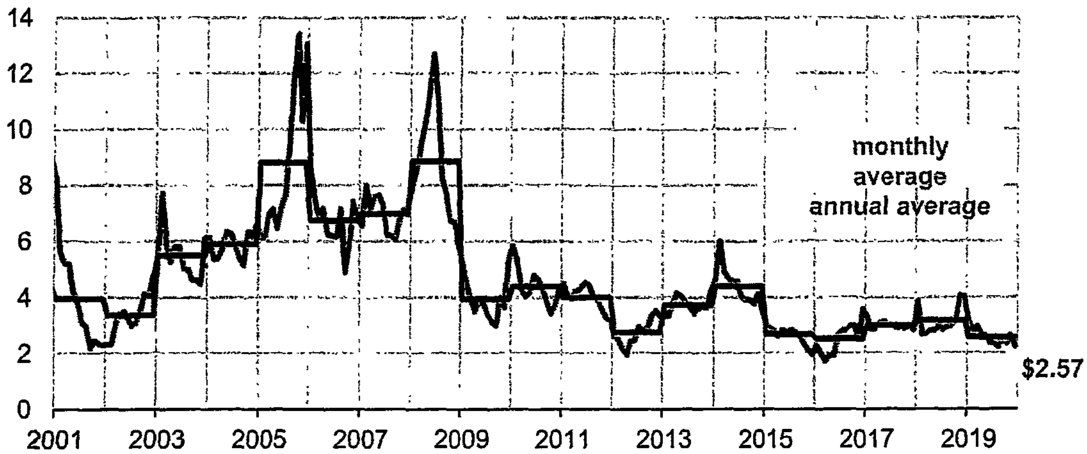
Source: U.S. Energy Information Administration, *Weekly Natural Gas Storage Report*
Principal contributor: David Manowitz

Today in Energy

January 9, 2020

Natural gas prices in 2019 were the lowest in the past three years

Monthly and annual average natural gas spot price at Henry Hub (2001-2019)
dollars per million British thermal units



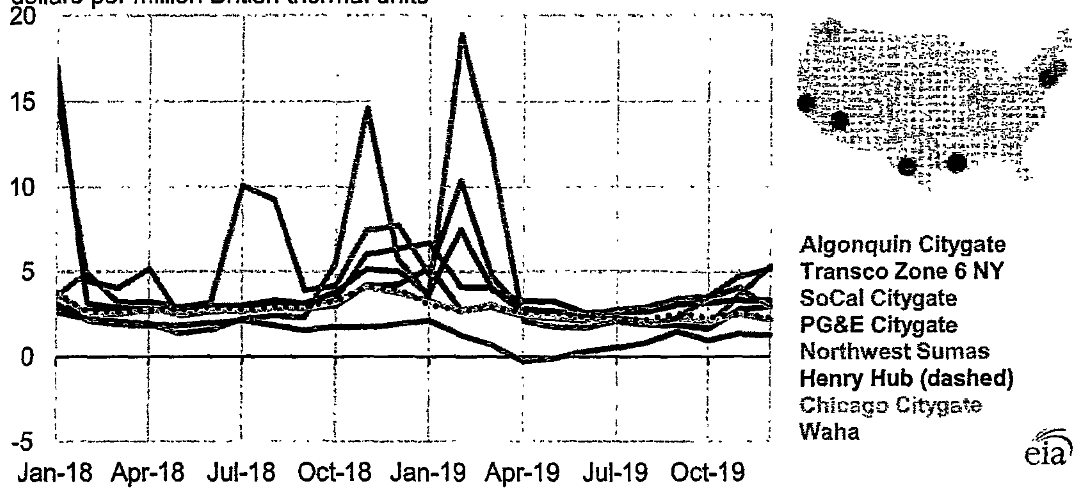
Source: U.S. Energy Information Administration, based on Refinitiv

In 2019, natural gas spot prices at the national benchmark Henry Hub in Louisiana averaged $2.57 per million British thermal units (MMBtu), about 60 cents per MMBtu lower than in 2018 and the lowest annual average price since 2016. Lower natural gas prices in 2019 supported higher consumption—particularly in the electric generation sector—and higher natural gas exports. Continued growth in domestic production of natural gas also supported lower natural gas prices throughout the year.

Monthly average natural gas prices at most key regional trading hubs in 2019 reached their highest levels in February, and they were relatively low and stable from April through December. In the Northeast, additional imports of liquefied natural gas (LNG) into New England limited price spikes during the winter of 2018–19. Despite a cold snap in the Midwest in February 2019, natural gas prices at Chicago Citygate were lower than during previous extreme weather events.

However, in the Pacific Northwest, unseasonably cold weather at the end of winter coupled with regional supply constraints and decreased storage inventories led to significant price spikes at the Northwest Sumas hub in March. Additional pipeline takeaway capacity in the Permian region eased some infrastructure constraints and increased regional prices at the Waha hub in western Texas after six consecutive months of prices lower than $1/MMBtu (March through August).

Monthly average natural gas spot prices at key trading hubs (Jan 2018-Dec 2019)
dollars per million British thermal units



Source: U.S. Energy Information Administration, based on Natural Gas Intelligence

Natural gas consumption in the residential and commercial sectors increased by 2% in 2019 compared with 2018, based on the U.S. Energy Information Administration's (EIA) monthly data through October and estimates for November and December. Natural gas use in the electric generation sector also increased in 2019, particularly in July and August when a heat wave in the Midwest and the Northeast led to record-high generation by natural gas-fired power plants.

Lower summer natural gas prices, which averaged $2.33/MMBtu in June through August (the lowest summer average Henry Hub natural gas price since 1998), have supported higher natural gas-fired generation in the summer months.

Dry natural gas production has grown every year since 2016. Production increased by 7.5 billion cubic feet per day (Bcf/d) (9%) through the first 10 months of the year after record growth in 2018. Sustained growth in natural gas production put downward pressure on prices, which continued to decline for most of 2019.

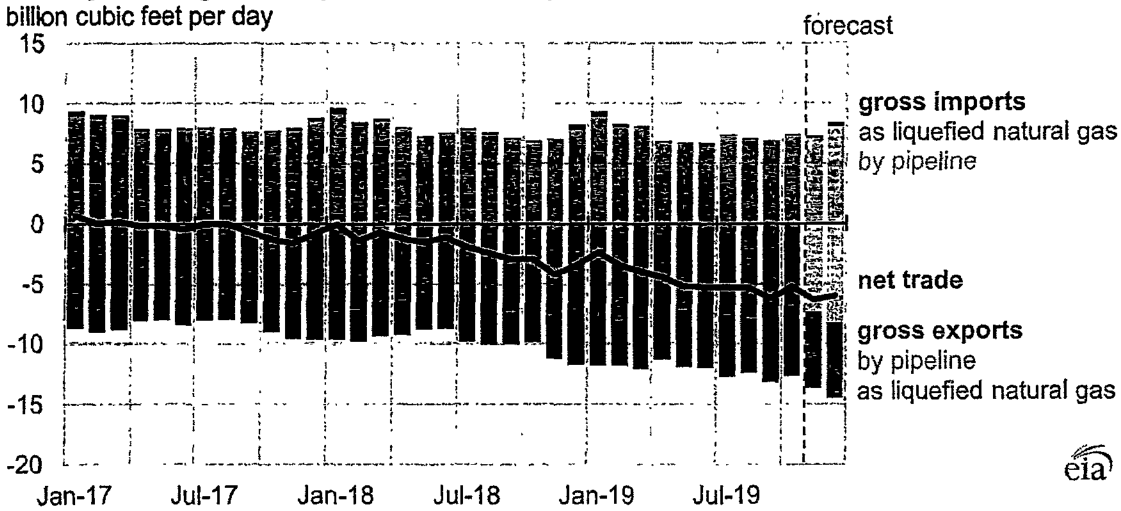
Natural gas storage inventories ended the withdrawal season at the end of March at their lowest levels since 2014. However, record natural gas production growth supported near-record injection activity during the injection season through October. The injection season ended with the second-highest net injection volume since 2014.

Most new pipelines placed in service in 2019 were located in the South Central and Northeast regions. These pipelines provide additional takeaway capacity out of the Permian and Appalachian supply basins and will serve growing demand for LNG exports, pipeline exports to Mexico, and U.S. natural gas-fired power generation.

In 2019, natural gas exports—both by pipeline to Mexico and as LNG—continued to grow. U.S. natural gas exports to Mexico by pipeline averaged 5.1 Bcf/d in the first 10 months of 2019, 0.4 Bcf/d more than the 2018 average. Following an expansion in U.S. cross-border pipeline capacity, several new pipelines in Mexico continued to experience delays, limiting growth in exports.

U.S. LNG exports set a new record in 2019, averaging an estimated 5.0 Bcf/d (69% higher than in 2018) as the United States became the third-largest global LNG exporter. Several new LNG facilities were placed in service in 2019. Louisiana's Cameron LNG placed its first liquefaction unit (referred to as a train) in service in May. Texas's Freeport LNG exported its first cargo from the newly commissioned Train 1 in September, followed by its first export cargo from Train 2 in December. Corpus Christi LNG (also in Texas) commissioned its second train in July. In December, Georgia's Elba Island placed in service the first three of its moveable modular liquefaction system (MMLS) units and exported its first LNG cargo.

Monthly natural gas trade (Jan 2017-Dec 2019)



Source: U.S. Energy Information Administration, *Natural Gas Monthly* and *Short-Term Energy Outlook*

Principal contributor: Victoria Zaretskaya

Henry Hub Natural Gas Futures Quotes

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Month	Options	Charts	Last	Change	Prior Settle	Open	High	Low	Volume	Hi / Low Limit	Updated
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MAR 2020	OPT		2.131	+0.019	2.112	2.095	2.155	2.083	11,381	No Limit / No Limit	08:15:40 CT 06 Jan 2020
APR 2020	OPT		2.131	+0.018	2.113	2.100	2.154	2.088	8,136	No Limit / No Limit	08:15:42 CT 06 Jan 2020
MAY 2020	OPT		2.170	+0.014	2.156	2.140	2.190	2.132	3,582	No Limit / No Limit	08:15.42 CT 06 Jan 2020
JUN 2020	OPT		2.226	+0.010	2.216	2,210	2.248	2.206	1,608	No Limit / No Limit	08:14:31 CT 06 Jan 2020
JUL 2020	OPT		2.285	+0.009	2 276	2.264	2.304	2.264	1,390	No Limit / No Limit	08:15:42 CT 06 Jan 2020
AUG 2020	OPT		2.305	+0.009	2.296	2.295	2.322	2.292	722	No Limit / No Limit	08:15:42 CT 06 Jan 2020
SEP 2020	OPT		2.299	+0.007	2.292	2.282	2.318	2.282	359	No Limit / No Limit	08.13:27 CT 06 Jan 2020
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NOV 2020	OPT		2.423	+0.005	2.418	2.406	2.439	2.406	312	No Limit / No Limit	08:13:27 CT 06 Jan 2020
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Legend: OPT Options | Price Chart

About This Report

Month	Options	Charts	Last	Change	Prior Settle	Open	High	Low	Volume	Hi / Low Limit	Updated
SEP 2021	OPT		2.333	+0.007	2.326	2.337	2.337	2.333	3	No Limit / No Limit	08:03:24 CT 06 Jan 2020
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Legend: OPT Options Price Chart

About This Report

Month	Options	Charts	Last	Change	Prior Settle	Open	High	Low	Volume	Hi / Low Limit	Updated
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SEP 2024	OPT		-	-	2.387	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
OCT 2024	OPT		-	-	2.410	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
NOV 2024	OPT		-	-	2.472	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
DEC 2024	OPT		-	-	2.652	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
JAN 2025	OPT		-	-	2.773	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
FEB 2025	OPT		-	-	2.743	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
MAR 2025	OPT		-	-	2.643	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
APR 2025	OPT		-	-	2.383	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
MAY 2025	OPT		-	-	2.371	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
JUN 2025	OPT		-	-	2.401	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
JUL 2025	OPT		-	-	2.433	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
AUG 2025	OPT		-	-	2.440	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
SEP 2025	OPT		-	-	2.434	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
OCT 2025	OPT		-	-	2.458	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
NOV 2025	OPT		-	-	2.520	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
DEC 2025	OPT		-	-	2.682	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
JAN 2026	OPT		-	-	2.802	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
FEB 2026	OPT		-	-	2.772	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
MAR 2026	OPT		-	-	2.662	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
APR 2026	OPT		-	-	2.402	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
MAY 2026	OPT		-	-	2.392	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
JUN 2026	OPT		-	-	2.422	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
JUL 2026	OPT		-	-	2.454	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
AUG 2026	OPT		-	-	2.468	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
SEP 2026	OPT		-	-	2.464	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
OCT 2026	OPT		-	-	2.488	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020

Legend: OPT Options Price Chart

About This Report

Month	Options	Charts	Last	Change	Prior Settle	Open	High	Low	Volume	Hi / Low Limit	Updated
NOV 2026	OPT		-	-	2.550	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
DEC 2026	OPT		-	-	2.712	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
JAN 2027	OPT		-	-	2.832	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
FEB 2027	OPT		-	-	2.802	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
MAR 2027	OPT		-	-	2.712	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
APR 2027	OPT		-	-	2.447	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
MAY 2027	OPT		-	-	2.437	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
JUN 2027	OPT		-	-	2.466	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
JUL 2027	OPT		-	-	2.498	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
AUG 2027	OPT		-	-	2.513	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
SEP 2027	OPT		-	-	2.518	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
OCT 2027	OPT		-	-	2.546	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
NOV 2027	OPT		-	-	2.612	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
DEC 2027	OPT		-	-	2.767	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
JAN 2028	OPT		-	-	2.887	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
FEB 2028	OPT		-	-	2.851	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
MAR 2028	OPT		-	-	2.761	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
APR 2028	OPT		-	-	2.486	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
MAY 2028	OPT		-	-	2.466	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
JUN 2028	OPT		-	-	2.498	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
JUL 2028	OPT		-	-	2.538	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
AUG 2028	OPT		-	-	2.553	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
SEP 2028	OPT		-	-	2.563	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
OCT 2028	OPT		-	-	2.598	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
NOV 2028	OPT		-	-	2.664	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
DEC 2028	OPT		-	-	2.816	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
JAN 2029	OPT		-	-	2.939	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
FEB 2029	OPT		-	-	2.904	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
MAR 2029	OPT		-	-	2.819	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
APR 2029	OPT		-	-	2.524	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
MAY 2029	OPT		-	-	2.502	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020

Legend: OPT Options Price Chart

About This Report

Month	Options	Charts	Last	Change	Prior Settle	Open	High	Low	Volume	Hi / Low Limit	Updated
JUN 2029	OPT		-	-	2.537	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
JUL 2029	OPT		-	-	2.577	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
AUG 2029	OPT		-	-	2.592	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
SEP 2029	OPT		-	-	2.602	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
OCT 2029	OPT		-	-	2.637	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
NOV 2029	OPT		-	-	2.709	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
DEC 2029	OPT		-	-	2.864	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
JAN 2030	OPT		-	-	2.994	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
FEB 2030	OPT		-	-	2.959	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
MAR 2030	OPT		-	-	2.874	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
APR 2030	OPT		-	-	2.569	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
MAY 2030	OPT		-	-	2.547	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
JUN 2030	OPT		-	-	2.582	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
JUL 2030	OPT		-	-	2.622	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
AUG 2030	OPT		-	-	2.662	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
SEP 2030	OPT		-	-	2.677	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
OCT 2030	OPT		-	-	2.723	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
NOV 2030	OPT		-	-	2.795	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
DEC 2030	OPT		-	-	2.950	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
JAN 2031	OPT		-	-	3.080	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
FEB 2031	OPT		-	-	3.045	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
MAR 2031	OPT		-	-	2.980	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
APR 2031	OPT		-	-	2.678	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
MAY 2031	OPT		-	-	2.656	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
JUN 2031	OPT		-	-	2.691	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
JUL 2031	OPT		-	-	2.731	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
AUG 2031	OPT		-	-	2.771	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
SEP 2031	OPT		-	-	2.786	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
OCT 2031	OPT		-	-	2.832	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
NOV 2031	OPT		-	-	2.904	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
DEC 2031	OPT		-	-	3.059	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020

Legend: OPT Options Price Chart

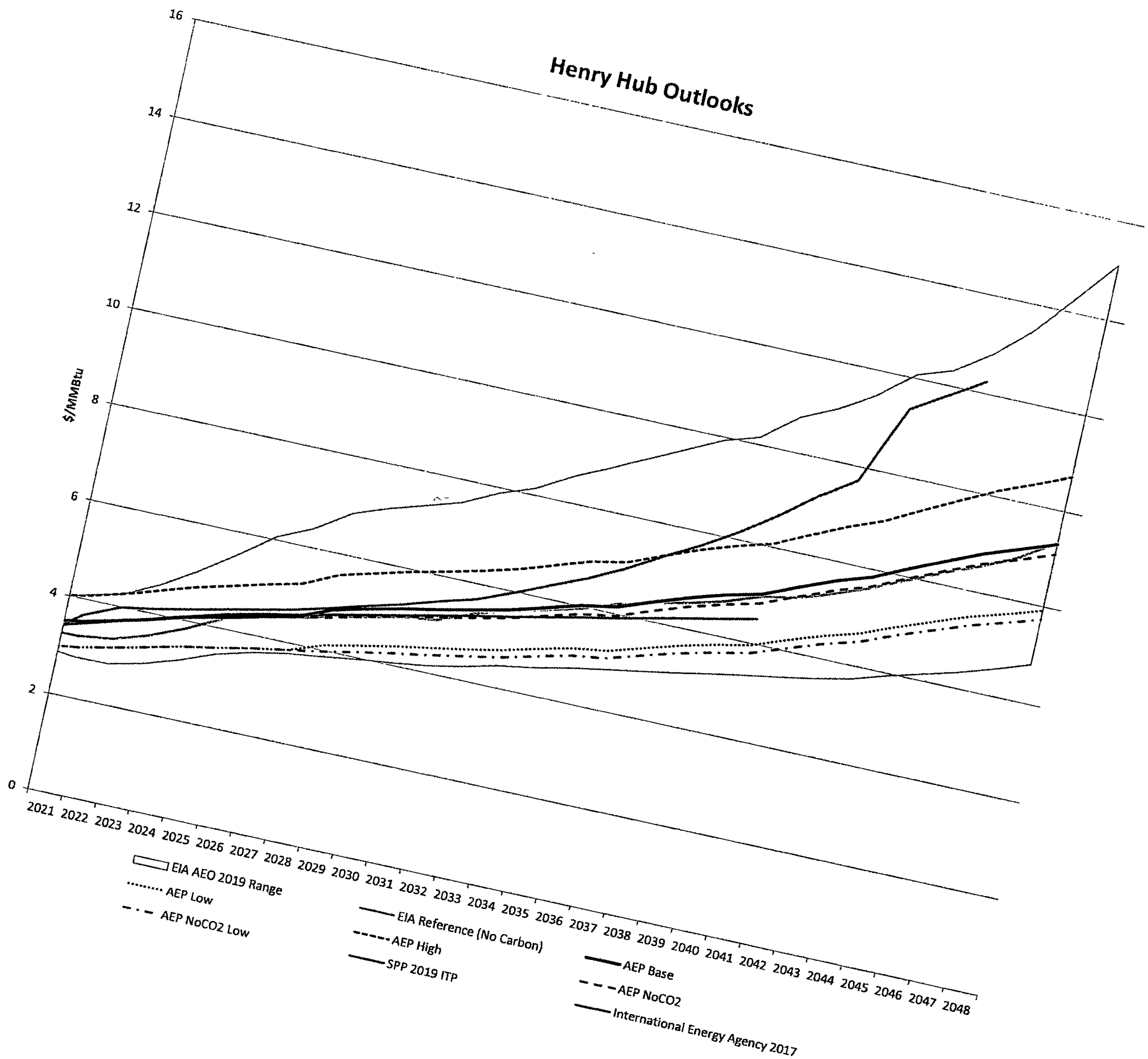
About This Report

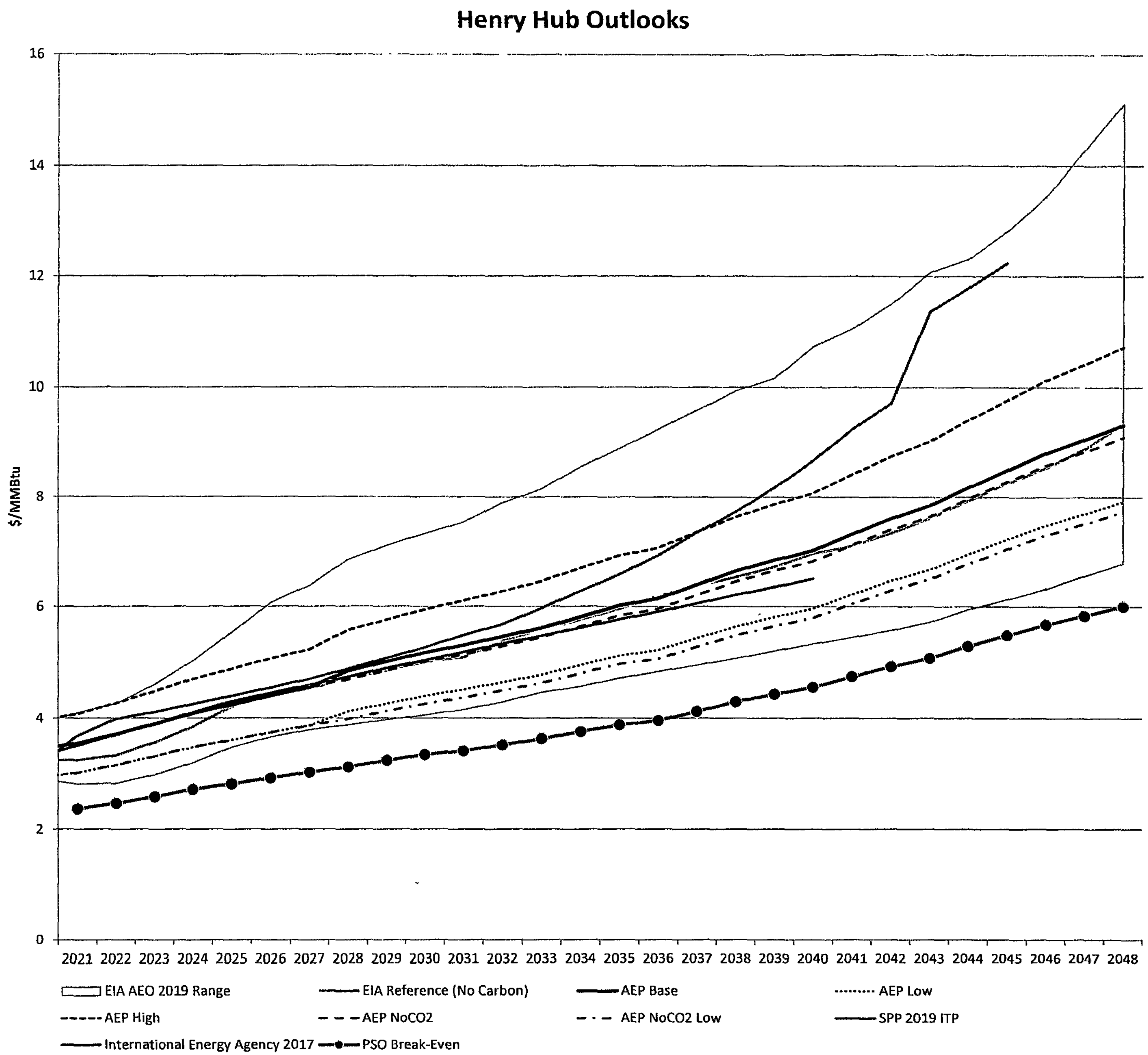
Month	Options	Charts	Last	Change	Prior Settle	Open	High	Low	Volume	Hi / Low Limit	Updated
JAN 2032	OPT		-	-	3.185	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
FEB 2032	OPT		-	-	3.150	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
MAR 2032	OPT		-	-	3.085	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
APR 2032	OPT		-	-	2.783	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
MAY 2032	OPT		-	-	2.761	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
JUN 2032	OPT		-	-	2.796	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
JUL 2032	OPT		-	-	2.836	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
AUG 2032	OPT		-	-	2.876	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
SEP 2032	OPT		-	-	2.891	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
OCT 2032	OPT		-	-	2.937	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
NOV 2032	OPT		-	-	3.009	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020
DEC 2032	OPT		-	-	3.164	-	-	-	0	No Limit / No Limit	16:00:00 CT 05 Jan 2020

Legend: OPT Options Price Chart

About This Report

	SPP	IEA	EIA				AEP				
SWEPCO Break-Even Errata	SPP 2019 ITP	International Energy Agency 2017	EIA Reference (No Carbon)	EIA High	EIA Low	EIA AEO 2019 Range	AEP Base	AEP High	AEP Low	AEP NoCO2	AEP NoCO2 Low
		3.10	3.10	3.48	2.90	0.58	3.21	3.69	2.73	3.21	2.73
	3.14	3.30	3.25	3.89	2.90	0.99	3.44	3.95	2.92	3.44	2.92
2.47	3.68	3.50	3.24	4.10	2.81	1.29	3.54	4.08	3.01	3.54	3.01
2.57	3.98	3.70	3.33	4.27	2.82	1.44	3.71	4.27	3.16	3.71	3.16
2.70	4.10	3.90	3.56	4.60	2.97	1.63	3.89	4.48	3.31	3.89	3.31
2.83	4.25	4.10	3.84	5.02	3.19	1.83	4.08	4.70	3.47	4.08	3.47
2.93	4.40	4.30	4.20	5.53	3.47	2.06	4.24	4.88	3.60	4.24	3.60
3.05	4.54	4.45	4.39	6.06	3.66	2.41	4.40	5.06	3.74	4.40	3.74
3.15	4.70	4.59	4.52	6.38	3.79	2.59	4.55	5.23	3.86	4.55	3.86
3.25	4.88	4.74	4.72	6.84	3.88	2.96	4.84	5.57	4.12	4.69	3.98
3.37	5.07	4.89	4.84	7.11	3.97	3.14	5.01	5.76	4.26	4.85	4.12
3.48	5.26	5.03	5.00	7.32	4.05	3.27	5.17	5.95	4.40	5.01	4.26
3.55	5.48	5.18	5.09	7.53	4.15	3.38	5.30	6.10	4.51	5.14	4.37
3.66	5.68	5.33	5.38	7.89	4.29	3.60	5.45	6.27	4.64	5.28	4.49
3.78	5.97	5.47	5.58	8.14	4.45	3.69	5.62	6.46	4.78	5.44	4.63
3.91	6.28	5.62	5.77	8.56	4.56	3.99	5.82	6.69	4.95	5.64	4.80
4.04	6.58	5.77	5.95	8.89	4.71	4.18	6.02	6.92	5.12	5.84	4.97
4.13	6.93	5.91	6.20	9.24	4.83	4.41	6.14	7.06	5.22	5.96	5.07
4.30	7.34	6.06	6.37	9.59	4.95	4.64	6.39	7.35	5.43	6.21	5.28
4.48	7.72	6.21	6.53	9.93	5.07	4.86	6.64	7.63	5.64	6.45	5.48
4.61	8.16	6.35	6.71	10.16	5.20	4.96	6.84	7.87	5.82	6.65	5.65
4.75	8.67	6.50	6.96	10.72	5.33	5.39	7.02	8.07	5.97	6.82	5.80
4.95	9.24		7.10	11.05	5.44	5.61	7.32	8.42	6.22	7.12	6.05
5.14	9.72		7.33	11.50	5.58	5.92	7.61	8.75	6.47	7.40	6.29
5.30	11.36		7.61	12.08	5.72	6.35	7.84	9.02	6.67	7.64	6.49
5.52	11.79		7.93	12.31	5.95	6.37	8.18	9.41	6.95	7.97	6.77
5.73	12.24		8.25	12.81	6.13	6.68	8.50	9.77	7.22	8.28	7.04
5.93			8.54	13.45	6.32	7.13	8.81	10.12	7.48	8.59	7.30
6.10			8.88	14.29	6.55	7.74	9.05	10.41	7.69	8.83	7.51
6.27			9.35	15.13	6.78	8.35	9.32	10.72	7.92	9.09	7.73
6.41											
6.59											
6.80											


Henry Hub Outlooks
$/MMBtu
0
2
4
6
8
10
12
14
16
2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045 2046 2047 2048
EIA AEO 2019 Range
AEP Low
AEP NoCO2 Low
EIA Reference (No Carbon)
AEP High
SPP 2019 ITP
AEP Base
AEP NoCO2
International Energy Agency 2017


Henry Hub Outlooks
$/MMBtu
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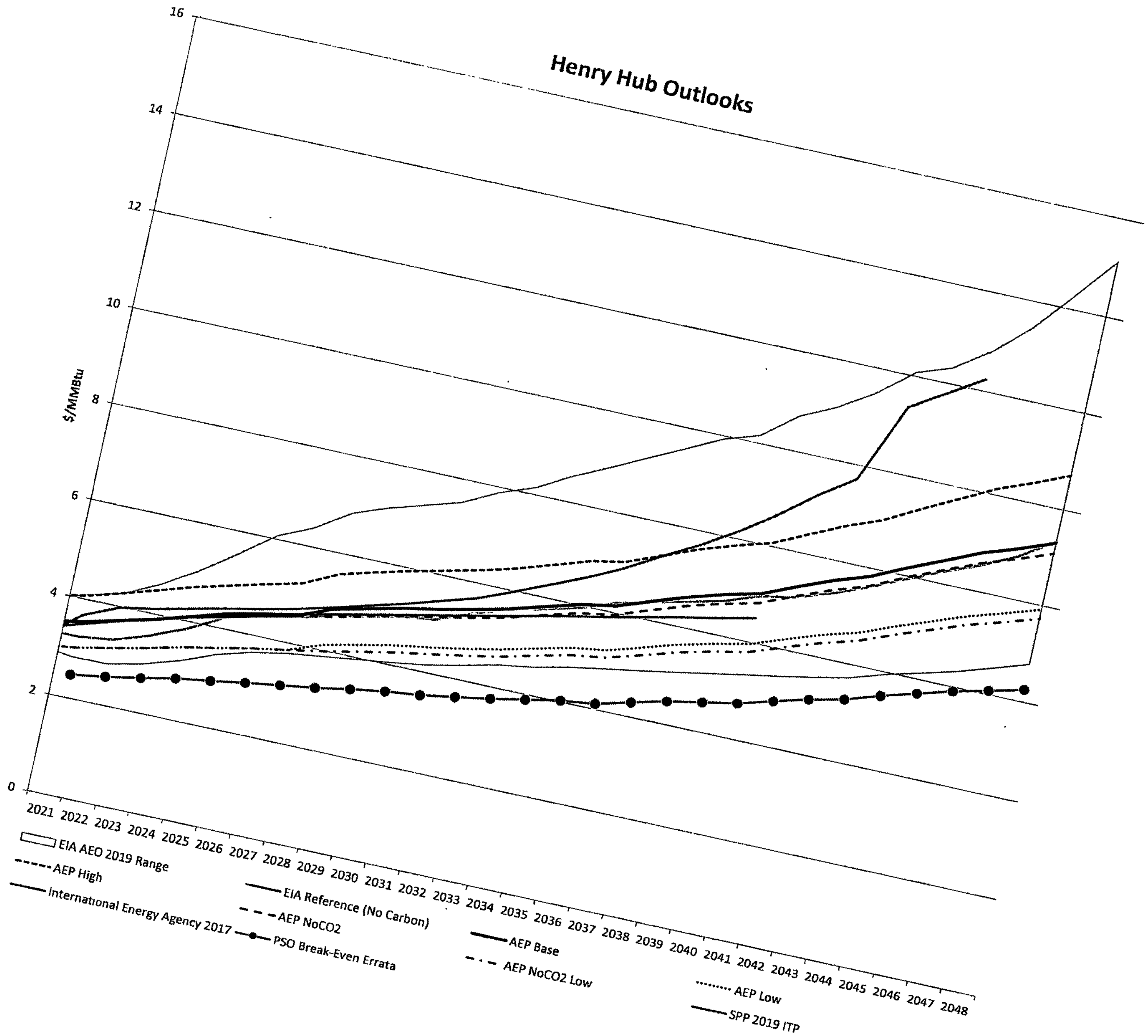
2
4
6
8
10
12
14
16
2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045 2046 2047 2048
EIA AEO 2019 Range
EIA Reference (No Carbon)
AEP Base
AEP Low
AEP High
AEP NoCO2
AEP NoCO2 Low
SPP 2019 ITP
International Energy Agency 2017
PSO Break-Even


Henry Hub Outlooks
$/MMBtu
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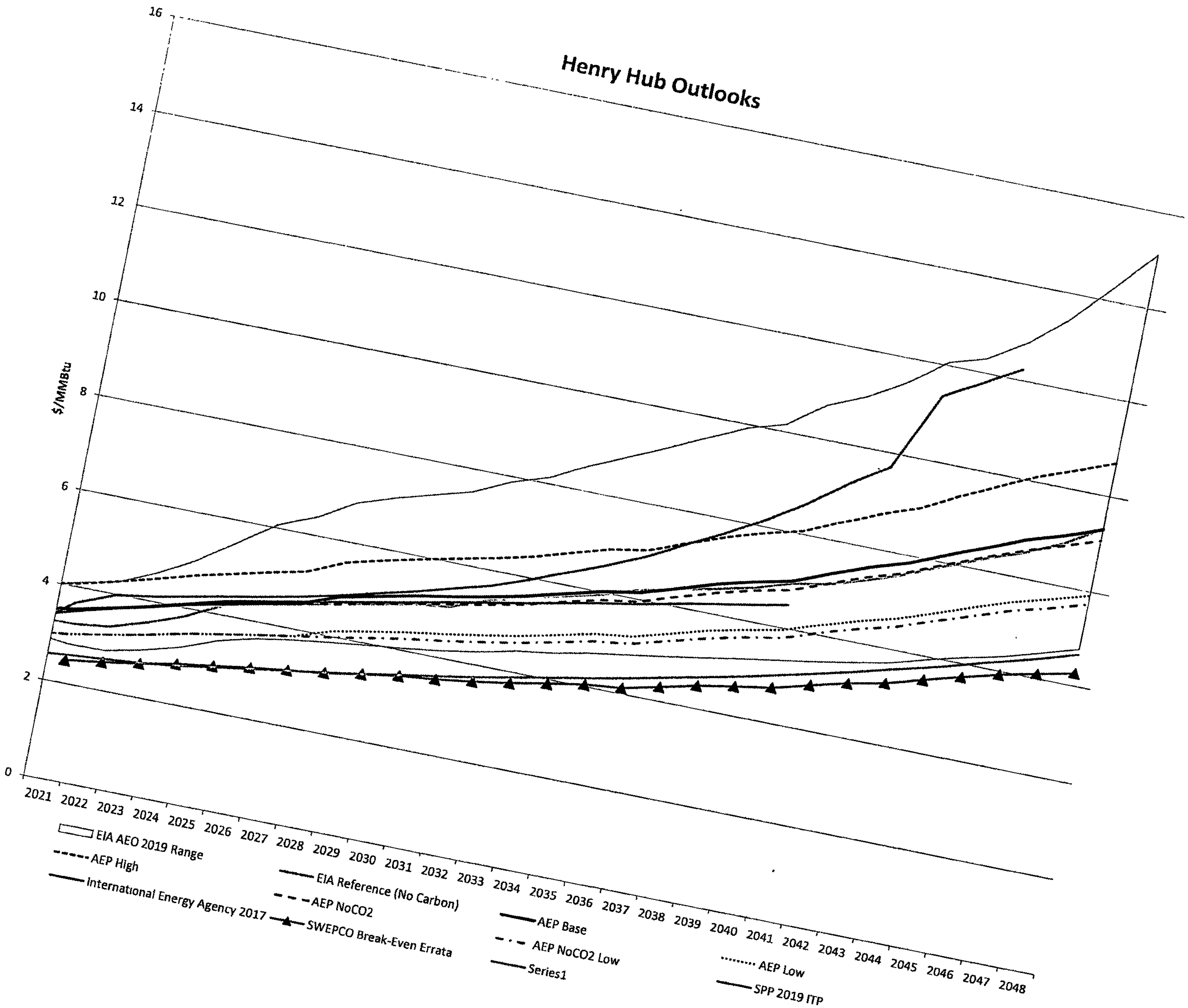
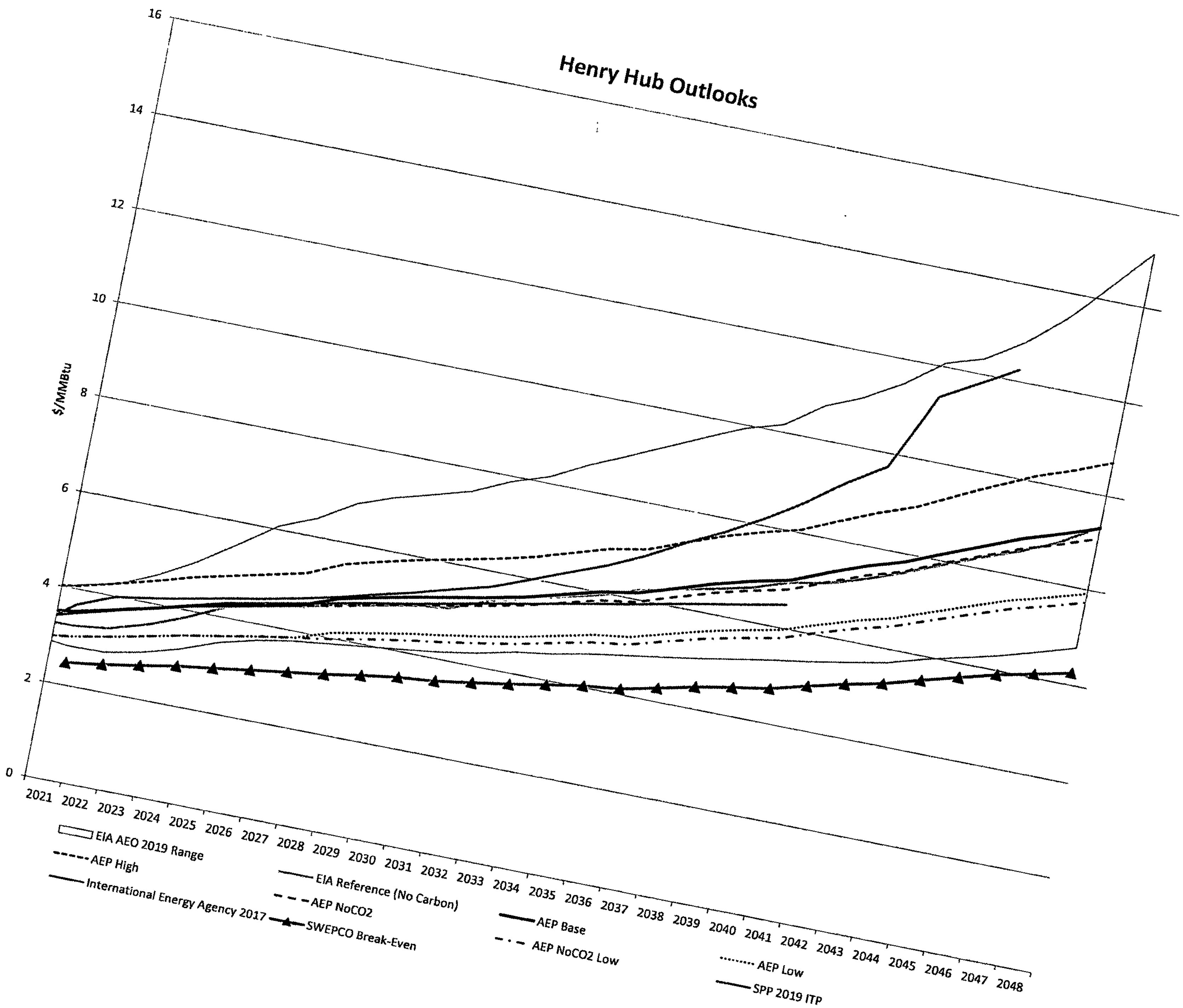
14
16
2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045 2046 2047 2048
EIA AEO 2019 Range
AEP High
International Energy Agency 2017
EIA Reference (No Carbon)
AEP NoCO2
PSO Break-Even Errata
AEP Base
AEP NoCO2 Low
AEP Low
SPP 2019 ITP


Henry Hub Outlooks
$/MMBtu
16
14
12
10
8
6
4
2
0
2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045 2046 2047 2048
EIA AEO 2019 Range
AEP High
International Energy Agency 2017
EIA Reference (No Carbon)
AEP NoCO2
SWEPCO Break-Even Errata
AEP Base
AEP NoCO2 Low
Series1
AEP Low
SPP 2019 ITP


Henry Hub Outlooks
$/MMBtu
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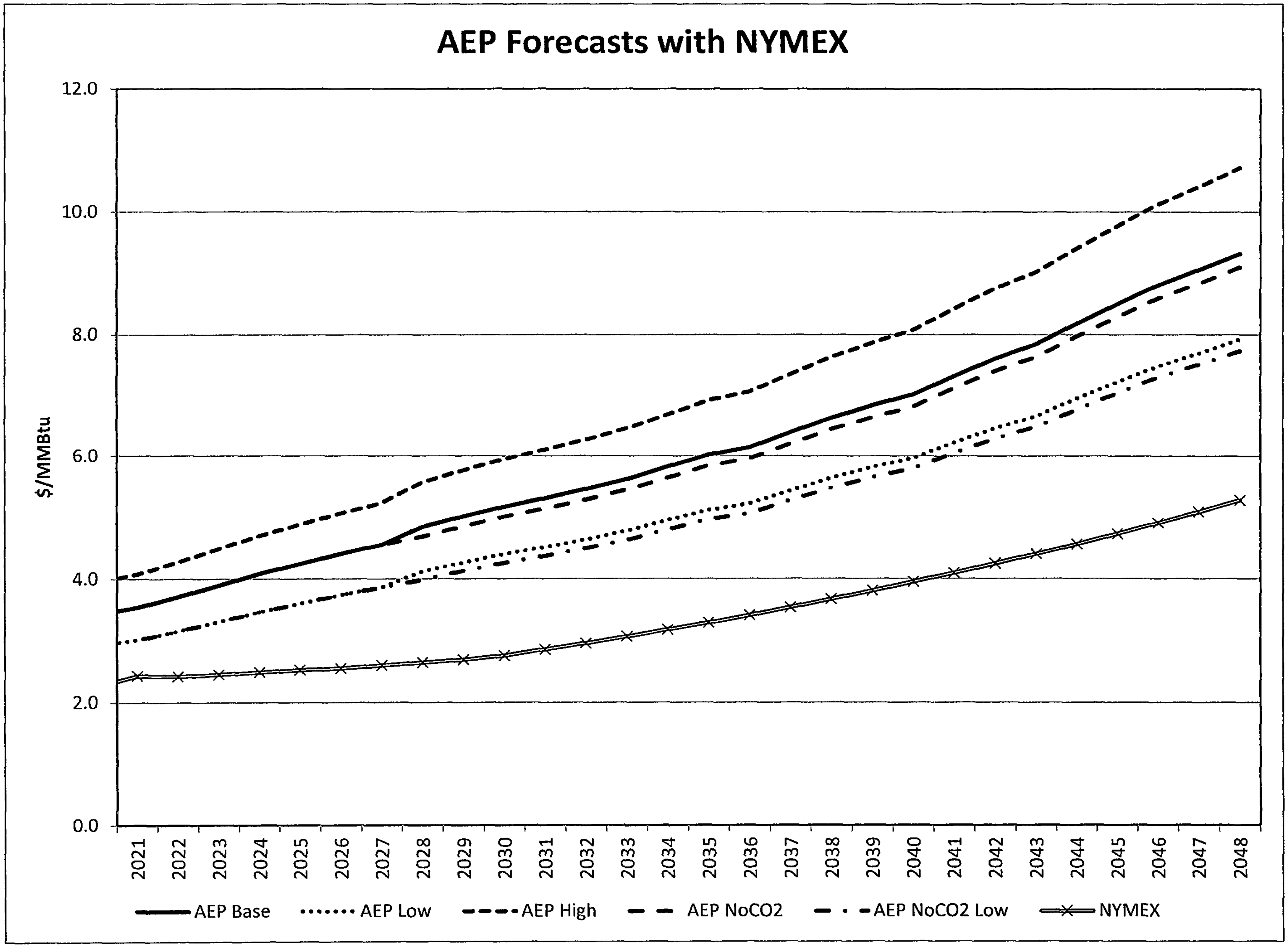
EIA AEO 2019 Range
AEP High
International Energy Agency 2017
EIA Reference (No Carbon)
AEP NoCO2
SWEPCO Break-Even
AEP Base
AEP NoCO2 Low
AEP Low
SPP 2019 ITP



AEP Forecasts with NYMEX
$/MMBtu
12.0
10.0
8.0
6.0
4.0
2.0
0.0
2021
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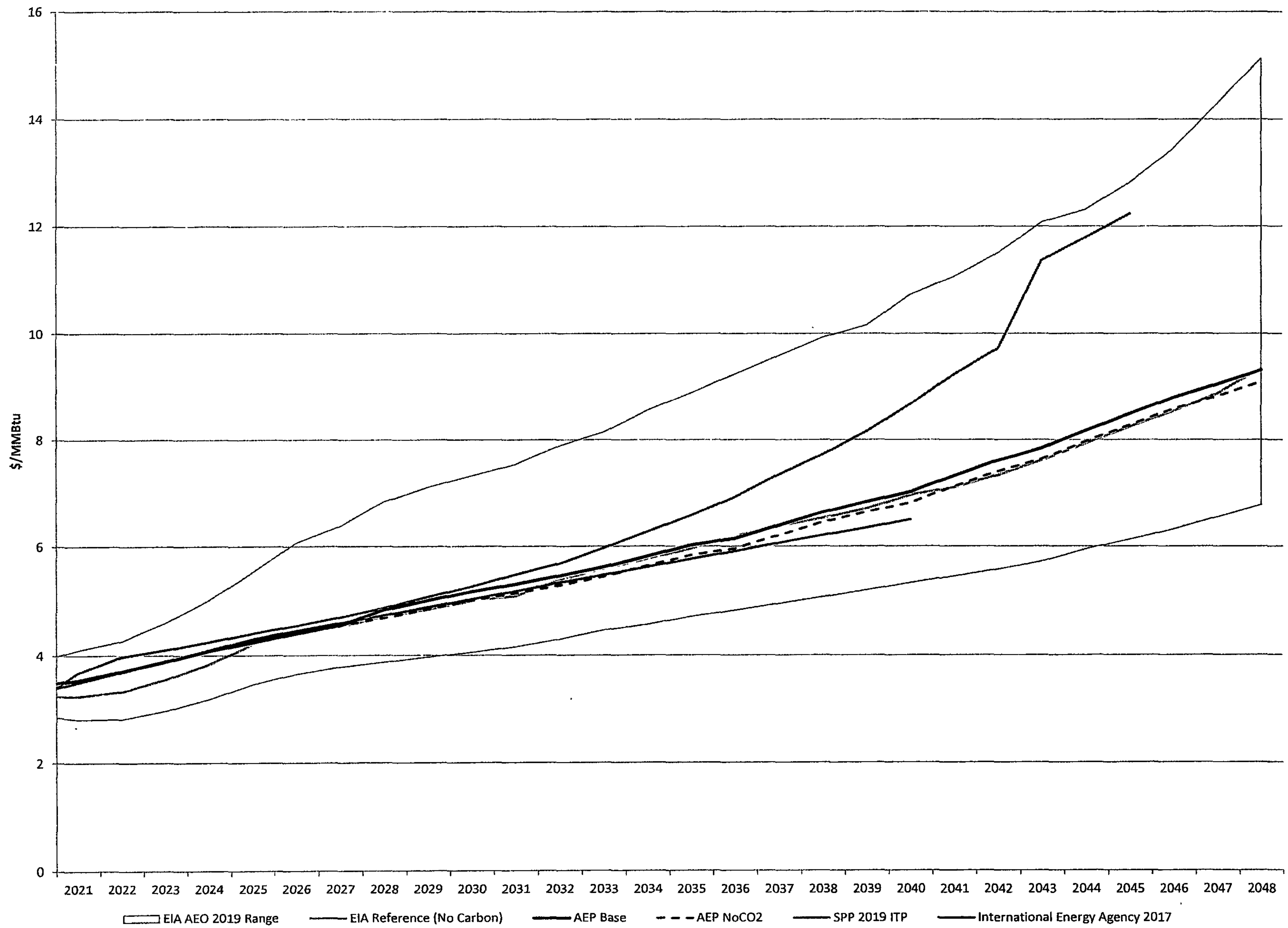
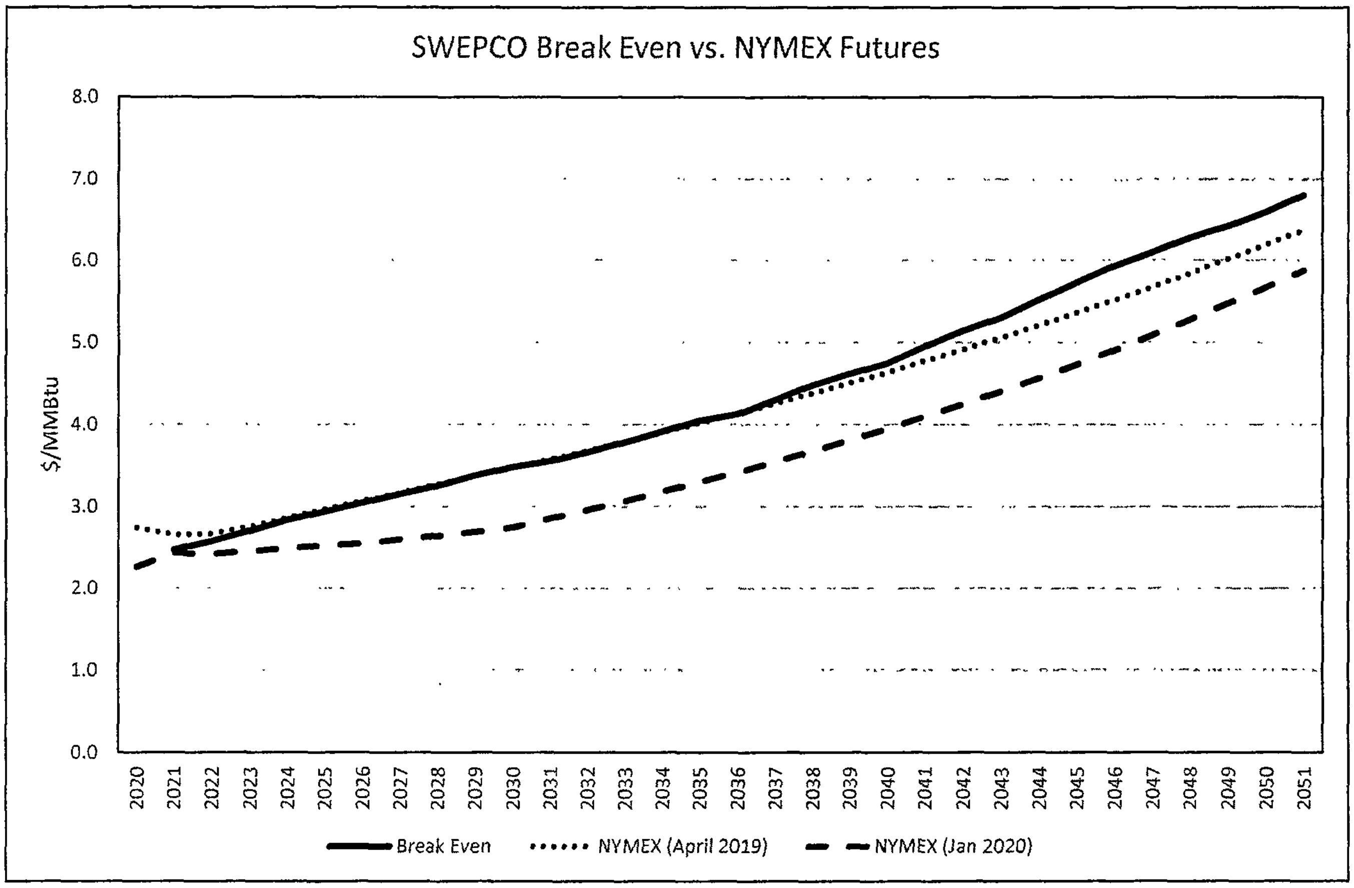
2044
2045
2046
2047
2048
AEP Base
AEP Low
AEP High
AEP NoCO2
AEP NoCO2 Low
NYMEX

Henry Hub Outlooks




SWEPCO Break Even vs. NYMEX Futures
$/MMBtu
8.0
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
2020
2021
2022
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2050
2051
Break Even
NYMEX (April 2019)
NYMEX (Jan 2020)

SPP 2019 ITP
Natual Gas ($/MMBtu)

Year	Henry Hub
2020	3.14
2021	3.68
2022	3.98
2023	4.10
2024	4.25
2025	4.40
2026	4.54
2027	4.70
2028	4.88
2029	5.07
2030	5.26
2031	5.48
2032	5.68
2033	5.97
2034	6.28
2035	6.58
2036	6.93
2037	7.34
2038	7.72
2039	8.16
2040	8.67
2041	9.24
2042	9.72
2043	11.36
2044	11.79
2045	12.24

IEA World Energy Outlook 2017
Natual Gas ($/MMBtu)

	Current Policies
2016	2.50
2017	2.70
2018	2.90
2019	3.10
2020	3.30
2021	3.50
2022	3.70
2023	3.90
2024	4.10
2025	4.30
2026	4.45
2027	4.59
2028	4.74
2029	4.89
2030	5.03
2031	5.18
2032	5.33
2033	5.47
2034	5.62
2035	5.77
2036	5.91
2037	6.06
2038	6.21
2039	6.35
2040	6.50

4/1/2019 Close

Month	Open	High	Low	Last	Change	Prior Settle	Estimated Volume	Prior Day Open Interest
Last Updated: Thursday, 04 Apr 2019 10:32 PM								
May-19	2.663	2.733	2.657	2.705	-0.003	2.708	136,338	276,378
Jun-19	2.715	2.774	2.707	2.746	-0.003	2.749	50,504	107,350
Jul-19	2.774	2.827	2.766	2.799	-0.003	2.802	43,580	102,907
Aug-19	2.800	2.849	2.790	2.820	-0.003	2.823	19,625	65,805
Sep-19	2.801	2.843	2.787	2.811	-0.003	2.814	24,874	133,987
Oct-19	2.815	2.861	2.807	2.825	-0.005	2.830	30,666	98,176
Nov-19	2.870	2.909	2.870	2.874	-0.004	2.878	12,132	61,779
Dec-19	3.000	3.040	3.000	3.007	-0.002	3.009	14,269	58,132
Jan-20	3.081	3.124	3.081	3.091	-0.003	3.094	12,005	46,878
Feb-20	3.032	3.060	3.030	3.030A	-0.004	3.034	1,590	21,519
Mar-20	2.930	2.944	2.910	2.914A	-0.003	2.917	4,893	35,139
Apr-20	2.623	2.636	2.610	2.610	-0.005	2.615	4,077	35,904
May-20	2.585	2.592	2.569	2.572	-0.003	2.575	3,159	21,394
Jun-20	2.610	2.610	2.594	2.596	-0.003	2.599	1,115	13,062
Jul-20	2.634	2.636	2.619	2.624	-0.002	2.626	124	10,260
Aug-20	2.635	2.636	2.622	2.624	-0.006	2.630	76	8,653
Sep-20	2.619	2.623B	2.605	2.608A	-0.004	2.612	95	9,517
Oct-20	2.636	2.648	2.626	2.626	-0.007	2.633	972	18,654
Nov-20	2.685	2.690	2.671	2.674	-0.005	2.679	693	8,897
Dec-20	2.835	2.838	2.822	2.831	-0.001	2.832	565	7,586
Jan-21	2.949	2.950B	2.936	2.942	-0.003	2.945	18	3,989
Feb-21	-	2.900B	2.893A	2.893A	-0.002	2.895	6	1,497
Mar-21	2.775	2.775	2.768A	2.768A	0.001	2.767	10	5,140
Apr-21	-	-	-	-	-0.001	2.512	7	4,783
May-21	-	-	-	-	-0.001	2.480	6	1,034
Jun-21	-	-	-	-	-0.001	2.514	6	901
Jul-21	-	-	-	-	-0.001	2.552	6	729
Aug-21	-	-	-	-	-0.001	2.562	6	890
Sep-21	-	-	-	-	-0.001	2.557	6	768
Oct-21	-	-	-	-	-0.001	2.583	6	1,041
Nov-21	-	-	-	-	-0.001	2.643	6	930
Dec-21	-	-	-	-	-0.001	2.828	6	992
Jan-22	-	-	-	-	-0.001	2.948	0	3,780
Feb-22	-	-	-	-	-0.001	2.898	0	247
Mar-22	-	-	-	-	-0.001	2.770	0	270
Apr-22	-	-	-	-	-0.001	2.520	0	196
May-22	-	-	-	-	-0.001	2.495	0	144
Jun-22	-	-	-	-	-0.001	2.527	0	107
Jul-22	-	-	-	-	-0.001	2.561	0	110
Aug-22	-	-	-	-	-0.001	2.571	0	114

Sep-22	-	-	-	-	-0.001	2.566	0	153
Oct-22	-	-	-	-	-0.001	2.590	0	116
Nov-22	-	-	-	-	-0.001	2.657	0	82
Dec-22	-	-	-	-	-0.001	2.842	0	76
Jan-23	-	-	-	-	-0.001	2.962	0	65
Feb-23	-	-	-	-	-0.001	2.917	0	43
Mar-23	-	-	-	-	-0.001	2.812	0	40
Apr-23	-	-	-	-	-0.001	2.592	0	22
May-23	-	-	-	-	-0.001	2.588	0	19
Jun-23	-	-	-	-	-0.001	2.627	0	15
Jul-23	-	-	-	-	-0.001	2.669	0	15
Aug-23	-	-	-	-	-0.001	2.686	0	26
Sep-23	-	-	-	-	-0.001	2.686	0	4
Oct-23	-	-	-	-	-0.001	2.716	0	26
Nov-23	-	-	-	-	-0.001	2.786	0	17
Dec-23	-	-	-	-	-0.001	2.967	0	14
Jan-24	-	-	-	-	-0.001	3.091	0	14
Feb-24	-	-	-	-	-0.001	3.051	0	11
Mar-24	-	-	-	-	-0.001	2.966	0	36
Apr-24	-	-	-	-	-0.001	2.726	0	25
May-24	-	-	-	-	-0.001	2.711	0	16
Jun-24	-	-	-	-	-0.001	2.740	0	11
Jul-24	-	-	-	-	-0.001	2.771	0	11
Aug-24	-	-	-	-	-0.001	2.784	0	11
Sep-24	-	-	-	-	-0.001	2.784	0	14
Oct-24	-	-	-	-	-0.001	2.806	0	11
Nov-24	-	-	-	-	-0.001	2.871	0	11
Dec-24	-	-	-	-	-0.001	3.028	0	11
Jan-25	-	-	-	-	-0.001	3.152	0	0
Feb-25	-	-	-	-	-0.001	3.114	0	0
Mar-25	-	-	-	-	-0.001	3.049	0	11
Apr-25	-	-	-	-	-0.001	2.839	0	11
May-25	-	-	-	-	-0.001	2.824	0	1
Jun-25	-	-	-	-	-0.001	2.853	0	0
Jul-25	-	-	-	-	-0.001	2.885	0	0
Aug-25	-	-	-	-	-0.001	2.903	0	0
Sep-25	-	-	-	-	-0.001	2.905	0	0
Oct-25	-	-	-	-	-0.001	2.931	0	0
Nov-25	-	-	-	-	-0.001	2.996	0	0
Dec-25	-	-	-	-	-0.001	3.148	0	0
Jan-26	-	-	-	-	-0.001	3.269	0	0
Feb-26	-	-	-	-	-0.001	3.232	0	0
Mar-26	-	-	-	-	-0.001	3.167	0	25
Apr-26	-	-	-	-	-0.001	2.942	0	25
May-26	-	-	-	-	-0.001	2.924	0	0
Jun-26	-	-	-	-	-0.001	2.949	0	0
Jul-26	-	-	-	-	-0.001	2.976	0	0

Aug-26	-	-	-	-	-0.001	2.995	0	0
Sep-26	-	-	-	-	-0.001	2.999	0	0
Oct-26	-	-	-	-	-0.001	3.027	0	0
Nov-26	-	-	-	-	-0.001	3.093	0	0
Dec-26	-	-	-	-	-0.001	3.245	0	0
Jan-27	-	-	-	-	-0.001	3.367	0	0
Feb-27	-	-	-	-	-0.001	3.331	0	0
Mar-27	-	-	-	-	-0.001	3.266	0	25
Apr-27	-	-	-	-	-0.001	3.041	0	25
May-27	-	-	-	-	-0.001	3.023	0	0
Jun-27	-	-	-	-	-0.001	3.050	0	0
Jul-27	-	-	-	-	-0.001	3.079	0	0
Aug-27	-	-	-	-	-0.001	3.097	0	0
Sep-27	-	-	-	-	-0.001	3.102	0	0
Oct-27	-	-	-	-	-0.001	3.130	0	0
Nov-27	-	-	-	-	-0.001	3.196	0	0
Dec-27	-	-	-	-	-0.001	3.347	0	0
Jan-28	-	-	-	-	-0.001	3.469	0	0
Feb-28	-	-	-	-	-0.001	3.434	0	0
Mar-28	-	-	-	-	-0.001	3.369	0	0
Apr-28	-	-	-	-	-0.001	3.113	0	0
May-28	-	-	-	-	-0.001	3.093	0	0
Jun-28	-	-	-	-	-0.001	3.123	0	0
Jul-28	-	-	-	-	-0.001	3.163	0	0
Aug-28	-	-	-	-	-0.001	3.203	0	0
Sep-28	-	-	-	-	-0.001	3.216	0	0
Oct-28	-	-	-	-	-0.001	3.262	0	0
Nov-28	-	-	-	-	-0.001	3.328	0	0
Dec-28	-	-	-	-	-0.001	3.479	0	0
Jan-29	-	-	-	-	-0.001	3.600	0	0
Feb-29	-	-	-	-	-0.001	3.565	0	0
Mar-29	-	-	-	-	-0.001	3.500	0	0
Apr-29	-	-	-	-	-0.001	3.205	0	0
May-29	-	-	-	-	-0.001	3.183	0	0
Jun-29	-	-	-	-	-0.001	3.213	0	0
Jul-29	-	-	-	-	-0.001	3.253	0	0
Aug-29	-	-	-	-	-0.001	3.293	0	0
Sep-29	-	-	-	-	-0.001	3.308	0	0
Oct-29	-	-	-	-	-0.001	3.354	0	0
Nov-29	-	-	-	-	-0.001	3.426	0	0
Dec-29	-	-	-	-	-0.001	3.578	0	0
Jan-30	-	-	-	-	-0.001	3.708	0	0
Feb-30	-	-	-	-	-0.001	3.673	0	0
Mar-30	-	-	-	-	-0.001	3.608	0	0
Apr-30	-	-	-	-	-0.001	3.301	0	0
May-30	-	-	-	-	-0.001	3.279	0	0
Jun-30	-	-	-	-	-0.001	3.314	0	0

Jul-30	-	-	-	-	-0.001	3.354	0	0
Aug-30	-	-	-	-	-0.001	3.394	0	0
Sep-30	-	-	-	-	-0.001	3.409	0	0
Oct-30	-	-	-	-	-0.001	3.455	0	0
Nov-30	-	-	-	-	-0.001	3.527	0	0
Dec-30	-	-	-	-	-0.001	3.682	0	0
Jan-31	-	-	-	-	-0.001	3.812	0	0
Feb-31	-	-	-	-	-0.001	3.777	0	0
Mar-31	-	-	-	-	-0.001	3.712	0	0
Apr-31	-	-	-	-	-0.001	3.402	0	0
May-31	-	-	-	-	-0.001	3.380	0	0
Jun-31	-	-	-	-	-0.001	3.415	0	0
Jul-31	-	-	-	-	-0.001	3.455	0	0
Aug-31	-	-	-	-	-0.001	3.495	0	0
Sep-31	-	-	-	-	-0.001	3.510	0	0
Oct-31	-	-	-	-	-0.001	3.556	0	0
Nov-31	-	-	-	-	-0.001	3.628	0	0
Dec-31	-	-	-	-	-0.001	3.783	0	0
Total							361,441	1,170,677

NYMEX Prior Settlement

	4/1/2019	1/6/2020
Jan-19		
Feb-19		
Mar-19		
Apr-19		
May-19	2.708	
Jun-19	2.749	
Jul-19	2.802	
Aug-19	2.823	
Sep-19	2.814	
Oct-19	2.830	
Nov-19	2.878	
Dec-19	3.009	
Jan-20	3.094	2.158 (a)
Feb-20	3.034	2.130
Mar-20	2.917	2.112
Apr-20	2.615	2.113
May-20	2.575	2.156
Jun-20	2.599	2.216
Jul-20	2.626	2.276
Aug-20	2.630	2.296
Sep-20	2.612	2.292
Oct-20	2.633	2.327
Nov-20	2.679	2.418
Dec-20	2.832	2.609
Jan-21	2.945	2.718
Feb-21	2.895	2.672
Mar-21	2.767	2.554
Apr-21	2.512	2.300
May-21	2.480	2.274
Jun-21	2.514	2.304
Jul-21	2.552	2.336
Aug-21	2.562	2.339
Sep-21	2.557	2.326
Oct-21	2.583	2.351
Nov-21	2.643	2.412
Dec-21	2.828	2.578
Jan-22	2.948	2.697
Feb-22	2.898	2.651
Mar-22	2.770	2.516
Apr-22	2.520	2.262
May-22	2.495	2.244
Jun-22	2.527	2.284
Jul-22	2.561	2.331

Annual Average

2019		
2020	2.737	2.259
2021	2.653	2.430
2022	2.662	2.417
2023	2.751	2.450
2024	2.861	2.487
2025	2.967	2.523
2026	3.068	2.549
2027	3.169	2.596
2028	3.271	2.640
2029	3.373	2.684
2030	3.475	2.746
2031	3.577	2.851
2032		2.956

(a) January 2020 price is from December 30, 2019 strip.

Aug-22	2.571	2.337
Sep-22	2.566	2.327
Oct-22	2.590	2.348
Nov-22	2.657	2.416
Dec-22	2.842	2.586
Jan-23	2.962	2.709
Feb-23	2.917	2.670
Mar-23	2.812	2.545
Apr-23	2.592	2.288
May-23	2.588	2.274
Jun-23	2.627	2.315
Jul-23	2.669	2.355
Aug-23	2.686	2.371
Sep-23	2.686	2.365
Oct-23	2.716	2.395
Nov-23	2.786	2.469
Dec-23	2.967	2.648
Jan-24	3.091	2.772
Feb-24	3.051	2.736
Mar-24	2.966	2.611
Apr-24	2.726	2.346
May-24	2.711	2.326
Jun-24	2.740	2.356
Jul-24	2.771	2.386
Aug-24	2.784	2.394
Sep-24	2.784	2.387
Oct-24	2.806	2.410
Nov-24	2.871	2.472
Dec-24	3.028	2.652
Jan-25	3.152	2.773
Feb-25	3.114	2.743
Mar-25	3.049	2.643
Apr-25	2.839	2.383
May-25	2.824	2.371
Jun-25	2.853	2.401
Jul-25	2.885	2.433
Aug-25	2.903	2.440
Sep-25	2.905	2.434
Oct-25	2.931	2.458
Nov-25	2.996	2.520
Dec-25	3.148	2.682
Jan-26	3.269	2.802
Feb-26	3.232	2.772
Mar-26	3.167	2.662
Apr-26	2.942	2.402
May-26	2.924	2.392
Jun-26	2.949	2.422

Jul-26	2.976	2.454
Aug-26	2.995	2.468
Sep-26	2.999	2.464
Oct-26	3.027	2.488
Nov-26	3.093	2.550
Dec-26	3.245	2.712
Jan-27	3.367	2.832
Feb-27	3.331	2.802
Mar-27	3.266	2.712
Apr-27	3.041	2.447
May-27	3.023	2.437
Jun-27	3.050	2.466
Jul-27	3.079	2.498
Aug-27	3.097	2.513
Sep-27	3.102	2.518
Oct-27	3.130	2.546
Nov-27	3.196	2.612
Dec-27	3.347	2.767
Jan-28	3.469	2.887
Feb-28	3.434	2.851
Mar-28	3.369	2.761
Apr-28	3.113	2.486
May-28	3.093	2.466
Jun-28	3.123	2.498
Jul-28	3.163	2.538
Aug-28	3.203	2.553
Sep-28	3.216	2.563
Oct-28	3.262	2.598
Nov-28	3.328	2.664
Dec-28	3.479	2.816
Jan-29	3.600	2.939
Feb-29	3.565	2.904
Mar-29	3.500	2.819
Apr-29	3.205	2.524
May-29	3.183	2.502
Jun-29	3.213	2.537
Jul-29	3.253	2.577
Aug-29	3.293	2.592
Sep-29	3.308	2.602
Oct-29	3.354	2.637
Nov-29	3.426	2.709
Dec-29	3.578	2.864
Jan-30	3.708	2.994
Feb-30	3.673	2.959
Mar-30	3.608	2.874
Apr-30	3.301	2.569
May-30	3.279	2.547

Jun-30	3.314	2.582
Jul-30	3.354	2.622
Aug-30	3.394	2.662
Sep-30	3.409	2.677
Oct-30	3.455	2.723
Nov-30	3.527	2.795
Dec-30	3.682	2.950
Jan-31	3.812	3.080
Feb-31	3.777	3.045
Mar-31	3.712	2.980
Apr-31	3.402	2.678
May-31	3.380	2.656
Jun-31	3.415	2.691
Jul-31	3.455	2.731
Aug-31	3.495	2.771
Sep-31	3.510	2.786
Oct-31	3.556	2.832
Nov-31	3.628	2.904
Dec-31	3.783	3.059
Jan-32		3.185
Feb-32		3.150
Mar-32		3.085
Apr-32		2.783
May-32		2.761
Jun-32		2.796
Jul-32		2.836
Aug-32		2.876
Sep-32		2.891
Oct-32		2.937
Nov-32		3.009
Dec-32		3.164

BEFORE THE CORPORATION COMMISSION OF THE STATE OF OKLAHOMA

APPLICATION OF PUBLIC SERVICE COMPANY OF OKLAHOMA (PSO) FOR APPROVAL OF THE COST RECOVERY OF THE SELECTED WIND FACILITIES (SWFs); A DETERMINATION THERE IS A NEED FOR THE SWFs; APPROVAL FOR FUTURE INCLUSION IN BASE RATES COST RECOVERY OF PRUDENT COSTS INCURRED BY PSO FOR THE SWFs; APPROVAL OF A TEMPORARY COST RECOVERY RIDER; APPROVAL OF CERTAIN ACCOUNTING PROCEDURES REGARDING FEDERAL PRODUCTION TAX CREDITS; AND SUCH OTHER RELIEF THE COMMISSION DEEMS PSO IS ENTITLED	CAUSE NO. PUD 201900048

FILED
DEC 10 2019
COURT CLERK'S OFFICE - OKC
CORPORATION COMMISSION
OF OKLAHOMA

JOINT STIPULATION AND SETTLEMENT AGREEMENT

COME NOW the undersigned parties to the above entitled cause and present the following Joint Stipulation and Settlement Agreement ("Joint Stipulation") for the Commission's review and approval as their compromise and settlement of all issues in this proceeding between the parties to this Joint Stipulation ("Stipulating Parties"). The Stipulating Parties represent to the Commission that this Joint Stipulation represents a fair, just and reasonable settlement of these issues, that the terms and conditions of the Joint Stipulation are in the public interest, and the Stipulating Parties urge the Commission to issue an Order in this Cause adopting and approving this Joint Stipulation.

It is hereby stipulated and agreed by and between the Stipulating Parties as follows:

TERMS OF THE JOINT STIPULATION AND SETTLEMENT AGREEMENT

Effective with the final order of the Oklahoma Corporation Commission ("OCC" or "Commission") approving all elements of this Joint Stipulation:

1. Approval of the Application.

Except as described below, the Stipulating Parties request that the Commission approve the relief requested by the Company in its Application. Public Service Company of Oklahoma ("PSO" or the "Company") is authorized to acquire up to 675 MW of installed capacity from the Selected Wind Facilities ("SWFs").

2. **Guarantees.**

(a) Cost Cap. PSO commits to a total cost cap of 100% of filed capital costs, including AFUDC and contingency, of $908,279,387. The Cost Cap will be reduced by the amount of any purchase price reduction realized by the Company under the terms and conditions of the PSAs, plus a proportionate share of contingency. Costs above the cap are not recoverable. When the Selected Wind Facilities are reviewed for placement in base rates, the Stipulating Parties agree that the "PSA Purchase Price" of the Selected Wind Facilities (as set forth in Exhibit JGD-3, *Total Installed Capacity Cost,* to the direct testimony of Company witness Joseph G. DeRuntz) will carry a rebuttable presumption of prudence. There shall be no exceptions to the cap for force majeure or changes in applicable law.

(b) PTC Eligibility. PSO will provide a guarantee, for cost recovery purposes, that the SWFs will be eligible for the applicable value of PTCs (80% for Traverse and Maverick and 100% for Sundance) for the actual output of the SWFs. PSO will be excused from this guarantee to the extent changes in federal law pertaining to PTCs, including changes to the Internal Revenue Code, directly reduce the value of PTCs. Based on the combined effect of the PTC and NCF Guarantees, customers will receive PTCs equal to the greater of actual or guaranteed MWh production upon completion of the SWFs.

(c) Net Capacity Factor (NCF). PSO guarantees a minimum net average capacity factor from the SWFs of P95 over the six five-year periods of the first thirty full years of operations (with the first year of full operations starting January 1, 2022). The NCF guarantee will be measured in MWh and at P95 will equal 11,269,460 MWh for each five-year period at 675 MW, adjusted ratably for the Company's share of any reduction in the final amount of MW installed by Invenergy and its subsidiaries pursuant to the purchase and sale agreements for the SWFs (the "PSAs"). The MWh guarantee for the sixth five-year period (years 26-30) will be adjusted ratably downward if the Sundance facility is constructed but is no longer in operation after its 30th year of operations.

NCF will be measured across all facilities on a combined basis and will be evaluated in a filing to be made no later than May 1 of the year following the 5-year performance period. Any make-whole payments resulting from a NCF production shortfall in any five-year period will flow back to customers through the FCA over the 12-month period following the performance evaluation covering each five-year performance period. (For example, any make-whole payment pertaining to years 1-5 will flow back to customers during the 12 months following the performance evaluation in year 6.) The calculation for determining amounts due to customers under this guarantee shall be as set out in Attachment 1 hereto. Hours impacted by force majeure will not be excluded from the calculation.

(d) Most Favored Nations (MFN). The MFN will apply to the Cost Cap, NCF Guarantee, PTC Eligibility Guarantee and any other term or condition adopted for SWEPCO in any of the state jurisdictions on behalf of which it acquires a share of the Selected Wind Facilities, whether through settlement or order issued by any such jurisdiction, to the extent such terms or conditions are more favorable to PSO's Oklahoma customers. The respective terms of this Joint Stipulation shall be deemed to be modified to incorporate those more favorable terms provided the term or condition is not unique to the SWEPCO jurisdiction (for example, the MFN will not apply to issues related to customer cost allocation, jurisdictional allocation and rate design). The Company will serve the Stipulating Parties with the orders and settlements described above promptly after they are issued and identify any provisions to which this clause applies.

3. **Other Settlement Terms and Conditions.**

(a) Deferred Tax Asset (DTA). The Company will earn a return on the DTA balance resulting from unused production tax credits over the first twenty (20) years of operation of the SWFs using its then applicable cost of long term debt (currently 4.72%) on any deferred tax asset balance.

(b) Off-system sales (OSS). PSO's fuel adjustment clause (FCA) Rider shall be modified such that PSO customers shall be credited with 100% of PSO's off-system sales margins effective January 1, 2021.

(c) Wind Facility Asset (WFA) Rider. The Stipulating Parties agree that the Company should be authorized to implement the WFA Rider as set forth in the Company's testimony, except as set forth below.

(i) The Company will seek to include each Selected Wind Facility in base rates as soon as practical after each Selected Wind Facility achieves commercial operation. For each Selected Wind Facility that can be included in the general base rate proceeding to be filed by the Company between October 2020 and October 2021, either as a test year item or a post-test year adjustment, the WFA Rider will sunset for that Selected Wind Facility on the date the revenue requirement associated with that Selected Wind Facility is included in base rates. If a Selected Wind Facility is not included in that general base rate proceeding, then the WFA Rider will sunset on the earlier of (A) July 1, 2023 and (B) the date that the revenue requirement associated with that Selected Wind Facility is included in base rates through a general base rate proceeding that will be filed by the Company within one year of the date that the facility achieves commercial operation. In either case, true-up of costs included in the rider, including any unrecovered deferrals, during the period it was in effect are excluded from the sunset. Revenues collected through the WFA Rider are subject to refund based upon the Commission's final determination of prudency.

(ii) Cost recovery pursuant to the WFA Rider is limited to the Company's filed capital costs and O&M. Additional capital investment and O&M in excess of the levels projected in the Company's testimony during the period the rider is in effect will not be recoverable through the WFA Rider.

(iii) The WFA Rider will recover the lesser of actual or filed capital costs and the lesser of actual or filed O&M. O&M costs will be limited to service agreement costs, land lease costs, and property taxes (as those categories are described in Exhibit JGD-5, *O&M and Capital Forecast,* to the direct testimony of Company witness Joseph G. DeRuntz). O&M costs will be deferred and only recovered through the WFA Rider after the costs are incurred.

(d) Gen-Tie. Nothing in this settlement should be interpreted as providing pre-approval for any future gen-tie lines related to the Selected Wind Facilities.

(e) Allocation of Revenue Requirement to Customer Classes. The revenue requirement associated with the filed capital cost of the SWFs will be allocated in PSO's WFA Rider to the Company's customer classes based on a blended demand/energy allocator, as each wind facility is placed in the WFA Rider, such that the revenue distribution resulting from such allocation will result in no net cost increase for the Company's residential customer class for the year following the addition of each wind facility in the WFA Rider using PSO's base case projections, including production cost savings, production tax credits, and congestion losses, as further described in Attachment 2 hereto. When each wind facility is initially placed in rate base in a PSO base rate proceeding, the Stipulating Parties agree to support or not object to the use of PSO's production cost allocator currently in effect for allocation of SWF costs to PSO's customer classes as part of any cost of service study in such base rate proceeding. The Stipulating Parties reserve the right in PSO's subsequent base rate proceeding, which the Company shall file by no later than January 1, 2025, to recommend an alternative method of cost allocation for the SWFs.

(f) Renewable Energy Credits (RECs). The proceeds, net of transaction costs, from the sale of RECs associated with the Selected Wind Facilities will be provided to customers through the FCA.

(g) Green Energy Choice Tariff (GECT). The Green Energy Choice Tariff will be modified to provide customers the option to purchase RECs available to the Company and derived from the Selected Wind Facilities for up to 100% of their monthly load based on total monthly billed energy usage (kWh). The REC price in the annual rate calculation will be the most recent 12-month weighted average REC transactional market price, as more fully set forth in the current GECT. Upon request, PSO will provide an attestation setting forth that the REC's provided under this special term are not double-counted and are retired on behalf of participating customers by the Company.

(h) Tariffs. The WCA Rider, FCA Rider and GECT that implement the terms and conditions of this Joint Stipulation are attached hereto as Attachments 3, 4 and 5, respectively.

4. Discovery and Motions.

As between and among the Stipulating Parties, all pending requests for discovery, and all motions pending before either the Commission or the Administrative Law Judge are hereby withdrawn.

5. General Reservations.

The Stipulating Parties represent and agree that, except as specifically otherwise provided herein:

(a) This Joint Stipulation represents a negotiated settlement for the purpose of compromising and settling all issues which were raised relating to this proceeding.

(b) Each of the undersigned counsel of record affirmatively represents that he or she has full authority to execute this Joint Stipulation on behalf of their client(s).

(c) None of the signatories hereto shall be prejudiced or bound by the terms of this Joint Stipulation in the event the Commission does not approve this Joint Stipulation nor shall any of the Stipulating Parties be prejudiced or bound by the terms of this Joint Stipulation should any appeal of a Commission order adopting this Joint Stipulation be filed with the Oklahoma Supreme Court.

(d) Nothing contained herein shall constitute an admission by any Stipulating Party that any allegation or contention in these proceedings as to any of the foregoing matters is true or valid and shall not in any respect constitute a determination by the Commission as to the merits of any allegations or contentions made in this rate proceeding.

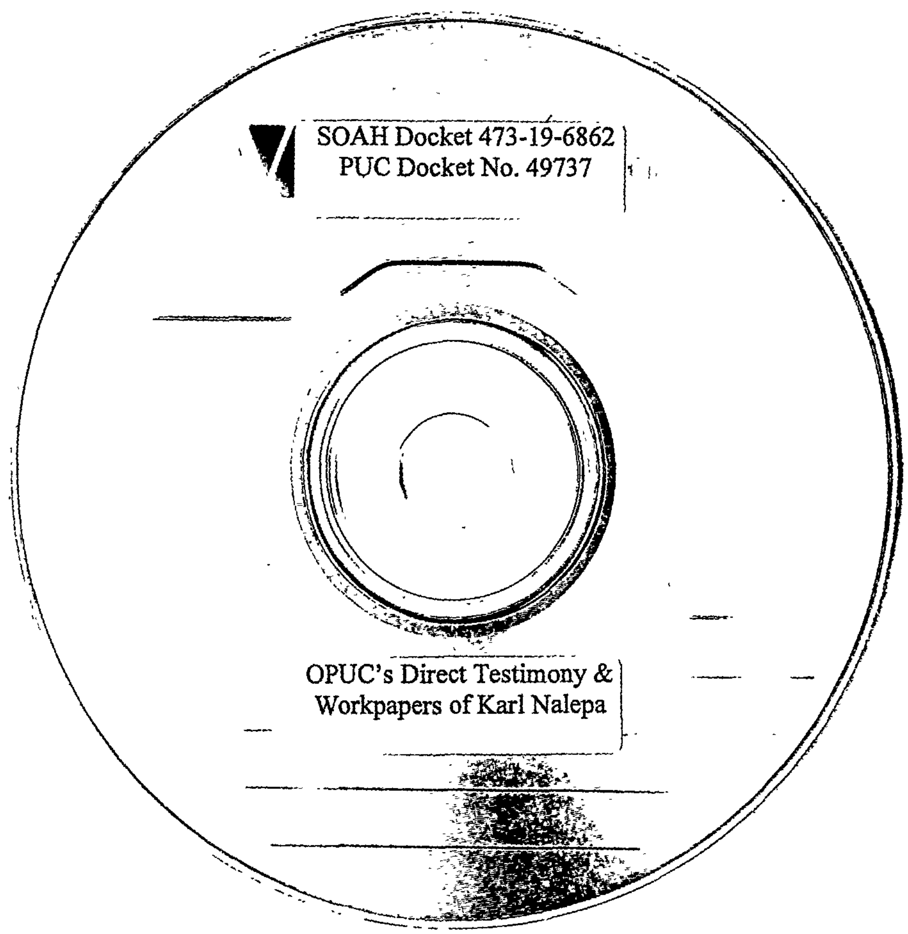
(e) The Stipulating Parties agree that the provisions of this Joint Stipulation are the result of extensive negotiations, and the terms and conditions of this Joint Stipulation are interdependent. The Stipulating Parties agree that settling the issues in this Joint Stipulation is in the public interest and, for that reason, they have entered into this Joint Stipulation to settle among themselves the issues in this Joint Stipulation. This Joint Stipulation shall not constitute nor be cited as a precedent nor deemed an admission by any Stipulating Party in any other proceeding except as necessary to enforce its terms before the Commission or any state court of competent jurisdiction. The Commission's decision, if it enters an order consistent with this Joint Stipulation, will be binding as to the matters decided regarding the issues described in this Joint Stipulation, but the decision will not be binding with respect to similar issues that might arise in other proceedings. A Stipulating Party's support of this Joint Stipulation may differ from its position or testimony in other causes. To the extent there is a difference, the Stipulating Parties are not waiving their positions in other causes. Because this is a stipulated agreement, the Stipulating Parties are under no obligation to take the same position as set out in this Joint Stipulation in other dockets.

6. **Non- Severability.**

The Stipulating Parties stipulate and agree that the agreements contained in this Joint Stipulation have resulted from negotiations among the Stipulating Parties and are interrelated and interdependent. The Stipulating Parties hereto specifically state and recognize that this Joint Stipulation represents a balancing of positions of each of the Stipulating Parties in consideration for the agreements and commitments made by the other Stipulating Parties in connection therewith. Therefore, in the event that the Commission does not approve and adopt the terms of this Joint Stipulation in total and without modification or condition (provided, however, that the affected party or parties may consent to such modification or condition), this Joint Stipulation shall be void and of no force and effect, and no Stipulating Party shall be bound by the agreements or provisions contained herein. The Stipulating Parties agree that neither this Joint Stipulation nor any of the provisions hereof shall become effective unless and until the Commission shall have entered an Order approving all of the terms and provisions as agreed by the parties to this Joint Stipulation and such Order becomes final and non-appealable.

WHEREFORE, the Stipulating Parties hereby submit this Joint Stipulation and Settlement Agreement to the Commission as their negotiated settlement of this proceeding with respect to all issues which were raised with respect to this Application, and respectfully request the Commission to issue an Order approving this Joint Stipulation and Settlement Agreement. The Stipulating Parties further request that the tariffs reflecting the terms of this Joint Stipulation as set forth in Attachments 3, 4 and 5 be approved and become effective after the tariffs have been reviewed and approved by the Director of the Public Utility Division.

[Signatures appear on next page]


SOAH Docket 473-19-6862
PUC Docket No. 49737
OPUC's Direct Testimony &
Workpapers of Karl Nalepa