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December 4, 2019

Via Electronic & Hand-Delivery
Walter L. Thomas, Jr.
Executive Secretary
Alabama Public Service Commission
100 N. Union Street
Montgomery, Alabama 36130

Re: Docket No. 32953
Petition for a Certificate of Convenience and Necessity

Dear Mr. Thomas:

On behalf of Intervenor AIEC, I am filing herewith the ***public*** version of the prefiled testimony and exhibits of Mr. Jeff Pollock in the above proceeding. The public version has also been e-filed with the Commission and served upon the parties of record. The confidential version of Mr. Pollock's testimony has been hand-delivered to the Commission's Legal Division. Accordingly, please find enclosed the public version of Mr. Pollock's testimony and exhibits.

Sincerely,

C. Richard Hill, Jr.

CRH/ff

Enclosures

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BEFORE THE
ALABAMA PUBLIC SERVICE COMMISSION

IN RE: **ALABAMA POWER COMPANY PETITION FOR A CERTIFICATE OF CONVENIENCE AND NECESSITY**	§ § § § § §	**DOCKET NO. 32953**

Public Disclosure Version

Direct Testimony and Exhibits

of

JEFFRY POLLOCK

On Behalf of

Alabama Industrial Energy Consumers

December 4, 2019

J. POLLOCK
INCORPORATED

BEFORE THE
ALABAMA PUBLIC SERVICE COMMISSION

IN RE: **ALABAMA POWER COMPANY PETITION FOR A CERTIFICATE OF CONVENIENCE AND NECESSITY**	§ § § § § §	**DOCKET NO. 32953**

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AFFIDAVIT OF JEFFRY POLLOCK

State of Missouri)
) **SS**
County of St. Louis)

Jeffry Pollock, being first duly sworn, on his oath states:

1. My name is Jeffry Pollock. I am President of J. Pollock, Incorporated, 12647 Olive Blvd., Suite 585, St. Louis, Missouri 63141. We have been retained by Occidental Permian Ltd. to testify in this proceeding on its behalf;

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony, Exhibits and Appendices A and B, which have been prepared in written form for introduction into evidence in Alabama Public Service Commission Docket No. 32953 and,

3. I hereby swear and affirm that my answers contained in the testimony are true and correct.

Jeffry Pollock

Subscribed and sworn to before me this 2nd day of December 2019.

Kitty Turner, Notary Public
Commission #: 15390610

My Commission expires on April 25, 2023.

KITTY TURNER
Notary Public - Notary Seal
State of Missouri
Commissioned for Lincoln County
My Commission Expires: April 25, 2023
Commission Number: 15390610

GLOSSARY OF ACRONYMS

Term	Definition
AIEC	Alabama Industrial Energy Consumers
APC	Alabama Power Company
APSC or Commission	Alabama Public Service Commission
BESS	Battery Energy Storage System
Calhoun	Calhoun Power Company
CCN	Certificate of Convenience and Necessity
CNP	Certified New Plant
Dominion	Dominion Energy, Inc.
ECR	Energy Cost Recovery
EUE	Expected Unserved Energy
GPC	Georgia Power Company
Hog Bayou	Hog Bayou Energy Center
IIC	Intercompany Interchange Contract
IRP	Integrated Resource Plan
IOU	Investor Owned Utility
kWh	Kilowatt-Hour
LOLE	Loss of Load Expectation
MW	Megawatts
MWh	Megawatt-Hour
NPCC	Northeast Power Coordinating Council
PPA	Power Purchase Agreement
RFP	Request for Proposal
RMS	Reserve Margin Study
RSE	Rate Stabilization and Equalization
Southern	The Southern Company
TRM	Target Reserve Margin

Direct Testimony of Jeffry Pollock

1. INTRODUCTION, QUALIFICATIONS AND SUMMARY

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jeffry Pollock; 12647 Olive Blvd., Suite 585, St. Louis, MO 63141.

Q WHAT IS YOUR OCCUPATION AND BY WHO ARE YOU EMPLOYED?

A I am an energy advisor and President of J. Pollock, Incorporated.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor of Science Degree in Electrical Engineering and a Master's in Business Administration from Washington University. Since graduation in 1975, I have been engaged in a variety of consulting assignments, including energy procurement and regulatory matters in both the United States and several Canadian provinces. As the primary regulatory advisor to the Alabama Industrial Energy Consumers (AIEC), I have participated in and/or monitored numerous regulatory matters involving Alabama Power Company (APC) that have come before the Alabama Public Service Commission (APSC) for several decades. I have also participated in regulatory proceedings involving APC's affiliated companies. My qualifications are documented in **Appendix A.** A partial list of my appearances is provided in **Appendix B** to this testimony.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A I am testifying on behalf of AIEC. AIEC members purchase substantial amounts of electricity from APC, primarily for manufacturing, under various rate schedules. AIEC has been a regular participant in regulatory activities involving APC that could potentially impact electricity rates for manufacturers. Because approval of APC's proposed Certificates of Convenience and Necessity (CCNs) will ultimately impact retail rates, AIEC has a keen interest in the outcome of this proceeding.

Q WHAT ISSUES ARE YOU ADDRESSING IN YOUR TESTIMONY?

A I shall first present an overview of APC's proposal for Commission approval of various CCNs to add capacity resources. I shall then discuss whether these capacity additions are needed to provide safe and reliable electricity service at the lowest reasonable cost. Finally, I will discuss APC's estimated rate impacts and cost recovery proposals.

Q ARE YOU SPONSORING ANY EXHIBITS?

A Yes. I am sponsoring **Exhibits JP-1** through **JP-4** which were prepared by me or under my supervision and direction.

Q WHAT WAS THE SCOPE OF YOUR REVIEW IN THIS PROCEEDING?

A I reviewed APC's non-public Application, including the supporting testimony and exhibits and APC's responses to data requests submitted by AIEC and other intervenors.

Q YOU DO NOT ADDRESS EVERY POTENTIAL ISSUE. SHOULD THAT BE INTERPRETED AS AN ENDORSEMENT OF APC'S PROPOSALS?

A No. This should not be interpreted as an endorsement of APC's proposals.

Summary of Findings and Recommendations

Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A My findings and recommendations are as follows:

- The primary drivers for APC's proposed capacity additions are (1) a substantial increase in the target reserve margin (TRM), (2) to replace an expiring purchased power agreement, (3) actual/planned generation retirements, and (4) other contractual obligations over the 2020 to 2029 period.
- The projected growth in retail peak demand is not a primary driver for the proposed capacity additions.
- The Southern Company (Southern) does not need additional capacity until [redacted].
- Until then, APC can meet its capacity obligations by continuing to make Reserve Equalization purchases under the Southern Intercompany Interchange Contract (IIC).
- APC's proposal to adopt a 26% system long-term winter TRM is based on the 2018 Reserve Margin study (2018 RMS) conducted by Southern Company Services. This same study was also sponsored by Georgia Power Company (GPC) in its most recent Integrated Resource Plan (IRP) filing before the Georgia Public Service Commission.
- Most investor-owned electric utilities (IOUs) operating in the southeast region, including those that are conducting seasonal planning, have adopted TRMs below the 26% that APC is proposing. This includes IOUs operating in Florida, which have more limited interconnections than Southern.
- Several factors appear to be putting undue upward pressure on the proposed winter TRM, including the extensive use of historical data to develop the study year weather patterns, load forecast uncertainty, dispatchers' peak load estimate error, winter forced outage rates, assumptions about the availability and cost of emergency power (*i.e.,* scarcity premium), and the cost that

customers would be willing to pay to avoid an outage (*i.e.,* value of lost load or unserved energy cost). Most of this historical data much pre-dates public awareness for the need to conduct more rigorous planning during the winter peak period.

- As seasonal planning has become a relatively new focal point, it would be reasonable to expect significant improvements in operational and planning tools that would both increase the accuracy of load forecasts and result in improved generator performance during periods of extreme cold weather.
- The industry has made, and continues to make, improvements in winter operations. It is unclear how these improvements are explicitly recognized in the 2018 RMS.
- Accordingly (and especially in light of the planning reserve margins adopted by other southeast IOUs), although it is reasonable for APC to conduct seasonal planning, it would be premature to adopt the 26% long-term system winter TRM without conducting further analysis and with collaboration between APC, the Commission Staff, and interested parties. This further analysis should be presented in a future proceeding.
- The Commission should deny the proposed CCNs until capacity is needed. Alternatively, the Commission should only approve CCNs as necessary to replace the capacity associated with the expiring power purchase agreement (PPA) with Calhoun Power Company (Calhoun).
- APC's projections that there will be only minimal rate impacts associated with the proposed CCNs are based on undocumented assumptions.
- APC should provide evidence supporting its proposal to recover a significant acquisition adjustment associated with the purchase of the Central Alabama Generating Station (Central Alabama) before a CCN is approved and any costs are recovered in rates.
- APC's proposals to recover the non-fuel costs associated with its proposed capacity additions through Rate CNP Parts A and B are unnecessary given

that Rate RSE currently uses a forward-looking test year. The forward-looking test year eliminates any regulatory lag associated with long-term capacity acquisitions for which the in-service dates and costs are both known and measurable.

- APC is proposing to "mark-up" the Central Alabama purchased capacity costs by the amount of "imputed debt." However, imputed debt is not an out-of-pocket expense. It is an adjustment to a utility's capital structure made by credit rating agencies to recognize the fixed payment obligations under long-term PPAs, such as the currently effective Calhoun purchase, in assessing various credit metrics.
- Only actual as-incurred purchased power costs should be recovered in rates.
- The fixed cost obligation is much lower under the proposed Central Alabama PPA than under the much larger and more expensive Calhoun PPA. Because the Calhoun PPA will expire in 2022 and because APC will have increased its equity ratio substantially, there is no reason to recover imputed debt costs from the former PPA in rates.
- The portion of the combined energy payments for the proposed solar projects associated with the battery energy storage facilities (BESS) should be recognized as imputed capacity because these costs are essential to recognizing the capacity value provided by renewable generators in determining resource adequacy. However, unless these imputed capacity costs are recovered in Rate RSE, they should be recovered in Rate ECR, rather than in Rate CNP Part B.

2. OVERVIEW

Q WHAT APPROVALS IS ALABAMA POWER SEEKING IN THIS PROCEEDING?

A APC is seeking approval of CCNs for various planned capacity additions, as well as cost recovery proposals applicable to each addition. Table 1 below summarizes the capacity additions proposed by APC.

Table 1
APC's Proposed Capacity Additions

Description	In-Service Date	Summer Capacity Rating (MW)	Estimated Annual Fixed Cost ($Million)
Barry 1 and 2	2020	160	N/A
Hog Bayou PPA*	2020	222	[redacted]
Anniston Solar, LLC	2022	68	[redacted]
Central Alabama Generating Station	2023	890	[redacted]
Al Solar C, LLC	2023	68	[redacted]
Barry Unit 8 CCGT	2023	653	[redacted]
Dallas County Solar	2024	68	[redacted]
Dothan Solar	2024	68	[redacted]
Talladega County Solar	2024	68	[redacted]
Barry Unit 8 CCGT Uprate	2026	[redacted]	[redacted]
Demand Side Options**	2020-2029	[redacted]	N/A
Total Capacity Additions		[redacted]	$174.6-$213.2

Sources: Response to SELC DR-1 AJ Support for Pages 1-1763 of Petition and Sierra DR-1 I-13, Attachment A.
* Annual cost excludes $[redacted] million imputed equity premium.
** [redacted] MW (resource deferral) increase in 600 Hour Interruptible load. APC projects [redacted] in the interruptible credits.

As Table 1 demonstrates, APC is proposing to add nearly [redacted] megawatts (MW) of supply-side resources (*i.e.*, generation capacity and power purchase agreements) and approximately [redacted] MW of demand-side resources (*i.e.*, primarily by expanding its interruptible program). Based on APC's estimates of the annual fixed costs associated with these resource additions, retail base rates would increase by approximately $[redacted] million per year. This represents a [redacted]% increase relative to APC's projected base revenues.

Q DOES AIEC SUPPORT ALL OF ALABAMA POWER'S PROPOSED CAPACITY ADDITIONS?

A No. As discussed below, APC does not need all of this new capacity to provide safe and reliable electricity service at the lowest reasonable cost.

3. CAPACITY NEED

Q WHAT IS ALABAMA POWER'S JUSTIFICATION FOR THE RESOURCE ADDITIONS SHOWN IN TABLE 1?

A The primary drivers for APC's proposed capacity additions are:

- Achieving a 26% "system" long-term target reserve margin (TRM) for the winter peak period;
- Projected capacity retirements; and
- Other contractual commitments.

Q WHAT DO YOU MEAN BY A SYSTEM RESERVE MARGIN?

A This term refers to Southern system. Southern operates as an integrated electric utility system. The Southern Operating Companies (which include APC) have operated their electric generating facilities and conducted their system operations pursuant to The IIC dated February 17, 2000.[1]

Q HOW DID ALABAMA POWER DETERMINE THAT A 26% LONG-TERM SYSTEM TARGET RESERVE MARGIN FOR THE WINTER PEAK IS APPROPRIATE?

A APC relied on a 2018 Reserve Margin Study (RMS) conducted by Southern Company Services. According to this study, the Southern system must achieve a 26% TRM for the winter peak and a 17% TRM for the summer peak to ensure that a supply outage will not occur more often than one day in ten years. The latter is referenced as a 1:10

[1] *Alabama Power Company – Amendment to July 3, 2018 Filing, Docket No. ER18-1947, et al. (Jul 24, 2018), Rate Schedule No. 138 (May 1, 2007).*

loss of load expectation (LOLE).[2]

Q DOES ALABAMA POWER HAVE TO ACHIEVE THESE LONG-TERM SYSTEM TARGET RESERVE MARGINS?

A No. To recognize diversity within the Southern system, APC would have to achieve long-term TRMs of 14.89% during the summer peak and 25.25% during the winter peak.[3] The 14.89% and 25.25% are the "diversified" TRMs for APC.

Q WHAT IS A DIVERSIFIED TARGET RESERVE MARGIN?

A The diversified TRM reflects the margins that each individual Southern Operating Company should achieve individually to ensure that Southern achieves its desired system TRM.

Q WHAT IS ALABAMA POWER'S CURRENT DIVERSIFIED LONG-TERM TARGET RESERVE MARGIN?

A APC's current diversified long-term TRM is 14.74%.[4]

Q YOU ALSO STATED THAT CAPACITY RETIREMENTS ARE A SIGNIFICANT DRIVER FOR THE PROPOSED RESOURCE ADDITIONS. HOW MUCH CAPACITY IS ALABAMA POWER PROPOSING TO RETIRE OVER THE NEXT TEN YEARS?

A Table 2 summarizes APC's capacity retirements over the next ten years.

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[2] *Direct Testimony of Jeffery B. Weathers, Exhibit JBW-1 at 49-50.*

[3] *Direct Testimony of John B. Kelley, Exhibit JBK-1 at 3.*

[4] *Id.*

Table 2 APC's Actual/Projected Capacity Retirements		
Description	**Effective Retirement Date**	**Summer Capacity Rating (MW)**
Gorgas 8, 9, and 10	2019	1,063
[redacted]	[redacted]	[redacted]
Westervelt	2022	6
Calhoun PPA	2023	632
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
Total Capacity Retirements		[redacted]
Source: APC's Response to Sierra DR-1 AJ Support for Pages 1-1763 of Petition.		

As Table 2 demonstrates, APC is proposing to retire over [redacted] MW of capacity. This is nearly [redacted] MW more than the proposed capacity additions for the same period.

Q IF ALABAMA POWER IS PROPOSING TO RETIRE MORE CAPACITY THAN IT IS PLANNING TO ADD, WON'T THIS CREATE A CAPACITY DEFICIT?

A No. APC is projecting declining, not increasing, peak demands over the 2020-2029 period. This is shown in **Exhibit JP-1**, which summarizes APC's projected winter and summer peak demands (column 1), cumulative load growth (column 2), cumulative capacity additions (column 3), and cumulative capacity retirements (column 4). As can be seen, APC is projecting a peak demand in 2029 that would be [redacted] MW (winter) and [redacted] MW (summer) below the corresponding 2019 projected peak demand. The projected reduction in both the winter and summer peak demand would more than offset the fact that APC is proposing to retire more capacity than it would acquire during the 2020-2029 period.

Q WHAT OTHER FACTORS ARE DRIVING ALABAMA POWER'S FUTURE CAPACITY NEEDS?

A APC is projecting to lose approximately [redacted] MW of wholesale load through 2025.[5] This load is included in APC's projected peak demand. APC is also contractually obligated to supply approximately [redacted] MW of capacity to wholesale customers under a System Sale. These contractual commitments will [redacted].

Q WHAT DO YOU CONCLUDE FROM YOUR ANALYSIS OF ALABAMA POWER'S PROJECTED PEAK DEMANDS?

A The projected long-term growth in peak demand is not a primary driver of APC's proposed resource capacity additions. These capacity additions are being driven primarily by the substantial increase in the long-term winter TRM, actual and planned capacity retirements, and other contractual commitments (*i.e.,* due to the assumed expiration of existing wholesale contracts).

[5] *APC Response to SELC DR-1 DPR-16, Attachment B. Further, an additional* [redacted] *will be lost sometime during the period 2023 to 2030.*

Q IS ALABAMA POWER PROJECTING TO ACHIEVE ITS TARGET RESERVE MARGINS DURING THE 2020 TO 2029 PERIOD?

A Yes. However, APC would not achieve its "diversified" winter TRM until [redacted]. This is shown in **Exhibit JP-2**. Page 1 shows APC's projected winter reserve margins, while page 2 shows APC's projected summer reserve margins under its proposed capacity resource plan.

Referring to page 1 (winter peak), APC is projecting a [redacted]% winter reserve margin in 2019. However, because of the retirement of the Gorgas Unit Nos. 8, 9 and 10, the subsequent expiration of the Calhoun Power Company (Calhoun) power purchase agreement (PPA), and other contractual commitments, APC's projected winter reserve margins will remain below the 25.25% diversified winter TRM. However, following the expiration of certain wholesale contracts, APC's projected winter reserve margins will exceed the 25.25% long-term diversified winter TRM until additional generation capacity is retired.[6]

The winter reserve margins are in stark contrast to the projected summer reserve margins. Even with the Gorgas Unit Nos. 8, 9 and 10 retirement and the subsequent expiration of the Calhoun PPA, APC is projecting that it will achieve reserve margins that are substantially above the 14.89% long-term diversified TRM for the summer period. The summer reserve margins are projected to exceed [redacted]% beginning in the year 2020, and they are projected to exceed [redacted]% and remain in excess thereof for the years 2024-2029. Thus, APC's proposed capacity additions would result in substantial excess capacity, particularly during the summer peak

[6] *APC's projected capacity retirements after 2025 are not at issue in this proceeding. APC has yet to demonstrate that these future retirements are cost-effective.*

months.

Q HAS ALABAMA POWER DEMONSTRATED THAT ITS PROPOSED RESOURCE PLAN IS REASONABLE?

A No. Southern does not need additional capacity until [redacted]. This was the reason why 2025 was used as a study year in the 2018 RMS. Quoting from the 2018 RMS:

> B. Study Year
>
> [redacted] The representative year selected for this study was 2025.[7]

Thus, APC can meet its capacity needs by continuing to make Reserve Equalization purchases under the IIC.

Q IF ALABAMA POWER MAKES RESERVE EQUALIZATION PURCHASES UNDER THE INTERCOMPANY INTERCHANGE CONTRACT, WHAT WOULD THIS RESERVE CAPACITY COST?

A The current IIC Reserve Equalization charge is $11 per kW-Yr.[8] This rate is but a fraction of the cost of the Hog Bayou Energy Center (Hog Bayou) PPA.

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[7] *Direct Testimony of Jeffery B. Weathers, Exhibit JBW-1 at 1. (emphasis added)*

[8] *Southern Company Services, Inc., 2020 Informational Filing – Intercompany Interchange Contract, Docket No. ER10-171-000. (Nov. 1, 2019)*

Q ALABAMA POWER WITNESS, MR. KELLEY, STATES THAT THE COMPANY CANNOT AND SHOULD NOT COUNT ON THE SUSTAINED AVAILABILITY OF CAPACITY OWNED BY ITS RETAIL AFFILIATES FOR USE IN SERVING THE REQUIREMENTS OF ALABAMA CUSTOMERS. IS THIS A LEGITIMATE REASON FOR OVERBUILDING THE ALABAMA POWER SYSTEM?

A No. Mr. Kelley provided no basis to support the assertion that APC will not be able to purchase reserve capacity from its Southern affiliates. In fact, APC assumes that the IIC will remain in effect and that Southern will continue planning for both production and transmission capacity on a coordinated, system-wide basis for the period 2020 through 2029.[9] The IIC has been in effect for decades — there is no known reason why it would not remain in effect for the foreseeable future. Further, an Operating Company must provide five years written notice to exit the IIC. To my knowledge, only Gulf Power Company has provided notice to exit the IIC because it was sold to NextEra and is no longer part of Southern.

Q MR. KELLEY ALSO ASSERTED THAT ITS AFFILIATE, GEORGIA POWER COMPANY, MAY LOSE SUBSTANTIAL CAPACITY IF IT DECIDES TO ACCELERATE THE RETIREMENT OF ITS BOWEN UNIT NOS. 1 AND 2. IS THIS A REASONABLE CONCERN?

A No. Georgia Power Company's (GPC's) Bowen Unit Nos. 1 and 2 represent approximately 1,450 MW of capacity. However, prior to retiring these units, GPC is committed to conducting capacity requests for proposals (RFPs) to replace these units. If these RFPs result in GPC acquiring more cost-effective resources than the

[9] *APC Response to AIEC DR-2 Interrogatory 30 and 31.*

continued operation of Bowen Unit Nos. 1 and 2, these units will be retired. Thus, the potential retirement of Bowen Unit Nos. 1 and 2 will not impact Southern's (or APC's) capacity needs.

Q ARE THERE ANY OTHER FACTORS THAT ARE EXACERBATING ALABAMA POWER'S PURPORTED CAPACITY NEEDS?

A Yes. As previously stated, APC is contractually obligated to support a System Sale of up to [redacted] MW through the year [redacted], and continuing at [redacted] MW thereafter to certain wholesale customers.

Q YOU PREVIOUSLY STATED THAT A MAJOR DRIVER FOR ALABAMA POWER'S PROPOSED CAPACITY ADDITIONS IS TO SATISFY A DIVERSIFIED WINTER TARGET RESERVE MARGIN OF 25.25%. SHOULD A WINTER TARGET RESERVE MARGIN BE ESTABLISHED AT THIS TIME?

A No. I do not disagree with the need for seasonal planning by Southern. Further, because APC has been a winter peaking system since the year 2010, it would not be unreasonable to establish a TRM for the winter period. However, I have concerns that Southern's 2018 RMS overstates the winter TRM.

Q WHAT ARE YOUR CONCERNS?

A As previously stated, the 2018 RMS uses a 2025 study year. Thus, it relies extensively on past historical data as well as assumptions about:

- Southern's generation and loads;
- The generation capacity, summer and winter peak demands, availability of power purchases from neighboring systems and the cost of these purchases;

- Scarcity premiums for power purchased during emergency conditions; and
- What consumers will pay to avoid an outage. This is measured in terms of the value of lost load or expected unserved energy (EUE) cost.

Q ASIDE FROM YOUR SPECIFIC CONCERNS ABOUT THE 2018 RESERVE MARGIN STUDY, WHY ELSE ARE YOU CONCERNED ABOUT THE PROPOSED LONG-TERM WINTER TARGET RESERVE MARGIN?

A APC is asking the APSC to approve a long-term diversified winter TRM that is far higher than the corresponding TRMs adopted by many other investor owned utilities (IOUs) in the Southeast. Further, like Southern, some of these utilities have specifically addressed winter reliability issues in establishing their TRMs.

Exhibit JP-3 lists the TRMs of these other utilities. As can be seen, the only IOU's comparable to APC are Kentucky Utilities Company and Louisville Gas and Electric Company. These IOUs conduct joint planning, but they are much smaller in size than Southern.

The next highest TRM is 21%, which is the winter peaking reserve margin for South Carolina Electric and Gas Company (SCE&G). SCE&G was recently acquired by Dominion Energy, Inc. (Dominion). Dominion operates in the PJM Interconnection. PJM has a 15.8% installed reserve margin requirement. However, Dominion's "diversified" reserve margin requirement is less than 12%. Assuming Dominion incorporates SCE&G in its overall planning, this would lower SCE&G's required TRM.

The next highest TRM is 20%, which is the reserve margin used by various Florida IOUs. However, these TRMs reflect the reality that Florida is a peninsula with limited interconnections with neighboring systems. Because of these limited interconnections, the Florida IOUs are not in the same position as Southern to request assistance during severe operating conditions.

Q ARE 20% AND HIGHER TARGET RESERVE MARGINS COMMONPLACE?

A No. According to the NERC, most reliability regions plan on a reference reserve margin of 20% or less.[10] This is documented in **Exhibit JP-4**, which is an excerpt from NERC's 2018 Long-Term Reliability Assessment. As can be seen, the referenced reserve margins are as low as 12% (MRO-Manitoba Hydro and Southwest Power Pool). Only one region (NPCC-Maritimes) has a reference reserve margin as high as 20%.

Q WHY ARE YOU CONCERNED ABOUT THE OVER-RELIANCE ON PROJECTIONS IN THE 2018 RESERVE MARGIN STUDY?

A Any forecast is inherently inaccurate; the longer the term, the less accurate the forecast. This is especially the case with the projected 2025 Southern generation and loads. Even more uncertain are Southern's projections of generation capacity, peak demand and availability of capacity purchases from neighboring utilities, as well as the cost of those purchases.

Q WHAT ARE THE DRIVERS AFFECTING THE WINTER RESERVE MARGIN?

A The key drivers affecting the winter TRM are:

- Generating unit (cold weather) outages: [redacted]%.
- Weather: [redacted]%.
- Load forecast uncertainty: [redacted]%.

[10] North American Electric Reliability Corporation.

- The availability and cost of purchasing capacity from the market: [redacted]%.
- Fuel (natural gas) supply: [redacted]%.[11]

Q WHAT DATA WAS USED TO MODEL UNIT OUTAGES DURING COLD WEATHER CONDITIONS?

A The 2018 RMS incorporated observations of historical generation unit outage events from 2006 through 2016.

Q DID SOUTHERN EXPERIENCE MANY SIGNIFICANT WINTER EVENTS DURING THIS PERIOD?

A No. Prior to 2014, there were few winter events affecting system planning and operations. Thus, most of the inputs pre-dated the 2015 RMS when Southern first publicly revealed its concerns about winter reliability impacts. Further, Southern had more than ample reserves to accommodate unexpected cold weather demands.

Q THE 2018 RMS STATES THAT SOME IMPROVEMENTS IN OUTAGE RATES WERE ASSUMED. DOES THIS ADDRESS THE POTENTIAL FOR FURTHER IMPROVEMENTS BY 2025?

A No. I acknowledge that some operational improvements were incorporated in the analysis (*i.e.,* no scheduled outages during the months December through February; a lower temperature threshold for cold weather outages). However, public awareness of winter reliability concerns is a relatively recent event. It is premature to assume that the industry will not adapt beyond the limited measures reflected in the 2018 RMS as a result of more refined operating practices and/or new technologies.

[11] *APC's Response to SELC DR-1 DPR-1 Attachment P.*

Q WHAT DATA WAS USED TO MODEL WEATHER PATTERNS?

A The 2018 RMS uses 54 historical years of weather data (from 1962 to 2015). These 54 weather patterns were then used to develop annual load shapes that would approximate what the load shape would be in the study year (2025) if the weather pattern matched one of those historical years.[12]

Q WHAT IS YOUR CONCERN ABOUT THE WEATHER DATA?

A The problem with using 54 historical annual weather patterns is whether or not these patterns are representative of future conditions (*i.e.*, 2025). In particular, two years, 1982 and 1985, are clearly outliers. Yet, they accounted for 15% of the total loss of load hours and 45% of the total EUE experienced during the entire 54 year period. The higher the number of loss of load hours and EUE, the higher the optimal reserve margin. Thus, the years 1982 and 1985 disproportionately impacted the study results.

Another problem with the use of the long-term historical data is that it may not capture any near-term warming trends. For example, the lowest winter temperature was [redacted]°F over the 54 year period. However, over the last 20 and 10 years of the 54 year period, respectively, the lowest winter temperatures were [redacted]°F and [redacted]°F, respectively.

Q WHAT ASSUMPTIONS WERE USED TO MODEL LOAD FORECAST UNCERTAINTY?

A The 2018 RMS used 24 years of observations on load forecast uncertainty (from 1993 through 2016) and four years of dispatchers' peak load estimate error (2012 -2015).

[12] *Direct Testimony of Jeffery B. Weathers, Exhibit JBW-1 at 1 and 2.*

As previously stated, most of the historical data pre-dated the public awareness of the growing concerns about winter reliability impacts.

Q IS PAST EXPERIENCE ON LOAD FORECAST UNCERTAINTY AND DISPATCHERS' PEAK LOAD ESTIMATE ERROR NECESSARILY INDICATIVE OF THE FUTURE?

A No. The problem with reliance on historical data is whether or not past experience will reasonability reflect operating experience for a future period (*i.e.*, 2025). It is reasonable to expect system planners and system operators will adapt to the new winter planning realities. While some adaptation has already occurred with respect to improved winter outage rates, the APSC should expect that the industry will implement new and more accurate forecasting tools.

Q ARE SYSTEM OPERATORS ADAPTING TO MEET THE CHALLENGES OF WIDE-SPREAD COLD WINTER WEATHER?

A Yes. One of NERC's key findings was that:

> Managing BPS [bulk power system] reliability during wide-area cold spells requires effective regional operating protocols and generator preparedness. In January 2018, extreme winter weather in the South Central United States resulted in season-high loads and increased generator outages over a nine-state area. Portions of the transmission system throughout the south were constrained as large power transfers flowed through the area to make up for forced generator outages. Reliability Coordinators (RCs) are preparing to meet future cold snaps with enhanced operating protocols for coordinating regional transmission flows during wide-area extreme events. SPP, MISO, and neighboring RCs have worked to clarify operating expectations, enhance communication processes, and develop training for operators on how to jointly mitigate reliability issues when extreme weather events simultaneously affect multiple RC areas. While ongoing winter preparation activities throughout the ERO incorporate the lessons from extreme winter events, NERC and the industry are taking additional steps to ensure BPS owners and operators

prepare for extreme cold weather by initiating a Reliability Standards development project.[13]

Q DO YOU HAVE ANY CONCERNS ABOUT THE ASSUMED AVAILABILITY AND COST OF MARKET PURCHASES DURING EXTREME WINTER WEATHER CONDITIONS?

A Yes. For example, the 2018 RMS assumes a scarcity premium of $[redacted] per MWh.[14] However, the $[redacted] per MWh scarcity premium has only occurred during the very worst case scenario (Polar Vortex of 2014) when there was no available reserve capacity. On the [redacted] when Southern purchased emergency power ([redacted]) and available reserves were also tight, the scarcity premium averaged less than $[redacted] per MWh.[15] Similarly, during periods of either moderate and high reserves, the historical scarcity premiums averaged less than $[redacted] and $[redacted] per MWh, respectively.[16]

Another key assumption is that power would not be available from merchant generators. This is unlikely because merchant generators have a strong incentive to maximize revenues by operating their facilities in a reliable and efficient manner, especially during periods of high market prices. High market prices typically occur during the summer and winter peak periods.

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[13] NERC, *2019-2020 Winter Reliability Assessment* (Nov. 2019) at 5 (Key Findings). Details on this Reliability Standards project can be found on the Project 2019-06 Cold Weather project page: https://www.nerc.com/pa/Stand/Pages/Project%202019-06%20Cold%20Weather.aspx

[14] *Direct Testimony of Jeffery B. Weathers at 8. A scarcity premium is the cost to purchase power during a period of very high capacity.*

[15] *APC Response to SELC DR-1 DPR-31, Attachment B.*

[16] *Id.*

Q HAS ALABAMA POWER PROVIDED ANY DOCUMENTATION SUPPORTING THE ASSUMPTION THAT MERCHANT GENERATORS WILL NOT PROVIDE POWER DURING EITHER THE SUMMER OR WINTER PEAK PERIODS?

A No.[17]

Q ARE ANY OTHER VARIABLES AFFECTING THE 2018 RESERVE MARGIN STUDY?

A Yes. Another key assumption in the 2018 RMS is what consumers would be willing to pay to avoid an outage. All other things being equal, the more costly an outage, the higher the optimal reserve margin.

Q WHAT WAS THE SOURCE FOR THE ASSUMED OUTAGE COSTS?

A The 2018 RMS used an outage cost survey that was conducted in 2011 of GPC and Mississippi Power Company customers. The outage costs from that 2011 study were escalated to 2025 dollars.

Q DO YOU HAVE ANY CONCERNS ABOUT THE OUTAGE COST ASSUMPTIONS USED IN THE STUDY?

A Yes. On closer examination, the outage costs used in the 2018 RMS were based solely on the worst case scenario from the 2011 study. The worst case scenario occurred when customers were asked to state what they would pay to be curtailed without notice. Table 3 below reveals that the outage costs declines if customers receive warning prior to a curtailment.

[17] *APC Response to AIEC DR-2 Interrogatory 36.*

Table 3
2012 Expected Unserved Energy Cost Estimates – by Customer Class

Outage Scenario	Residential ($/kWh)	Commercial ($/kWh)	Industrial ($/kWh)	Large Business ($/kWh)
1 hour, no warning, summer	[redacted]	[redacted]	[redacted]	[redacted]
1 hour, with warning, summer	[redacted]	[redacted]	[redacted]	[redacted]
2 hours, with warning, summer	[redacted]	[redacted]	[redacted]	[redacted]
8 hours, no warning, summer	[redacted]	[redacted]	[redacted]	[redacted]
8 hours, with warning, summer	[redacted]	[redacted]	[redacted]	[redacted]
1 hour, no warning, winter	[redacted]	[redacted]	[redacted]	[redacted]

Source: APC Response to SELC DR-1 DPR-38 Attachment A, Table 1-4.

Q **ARE THE RESULTS OF THE 2018 RESERVE MARGIN STUDY SENSITIVE TO ASSUMPTIONS ABOUT SCARCITY PREMIUMS, OUTAGE COSTS, WINTER OUTAGES AND WEATHER PATTERNS?**

A Yes. For example, changing only the outage cost from $[redacted] to $[redacted] per MWh lowered the optimal reserve margin from [redacted]% to [redacted]%. In addition to lower outage costs and scarcity premium, improvements that reduce load forecast uncertainty, dispatcher peak load error, and winter generator outages would further reduce the optimal TRM.

Q **HAS ANY OTHER REGULATORY COMMISSION ORDERED A FURTHER ASSESSMENT OF SOUTHERN'S LONG-TERM WINTER TARGET RESERVE MARGIN?**

A Yes. The very same 2018 RMS was filed in GPC's most recent IRP filing. GPC also proposed raising the system long-term winter TRM to 26% as APC is currently proposing. However, the Georgia Public Service Commission deferred approving GPC's proposed winter TRM and authorized further discussion to address this issue before GPC's next IRP filing (to be filed in 2022).

Q WHAT DO YOU RECOMMEND?

A First, because Southern does not need additional capacity until [redacted], the APSC should deny CCNs for all but Barry Unit 8. Coupled with the other capacity additions and Reserve Equalization purchases from the IIC, APC will be able to provide safe and reliable electricity at the lowest reasonable cost.

However, if the APSC determines that APC needs additional capacity prior to [redacted], it should approve CCNs only for those capacity resources needed to replace the expiring Calhoun PPA until a specific winter TRM is approved. APC's proposal to acquire Central Alabama would more than satisfy this need. Alternatively, approval of CCNs for the Hog Bayou PPA and the solar/storage projects (but not for the Central Alabama acquisition) would also suffice.

Second, based on my concerns about the 2018 RMS (as previously discussed), I recommend that the APSC require APC to work with the Commission Staff and interested parties to review and refine the assumptions about customers' outage costs, future weather patterns, load forecast uncertainty, dispatchers peak load estimate error, and winter generating unit outage rates. This review would provide a more realistic assessment of future conditions that also incorporate more robust improvements relative to historical experience. This assessment should be presented in APC's next IRP filing. Until this further assessment is made, the APSC should not approve the proposed long-term diversified winter TRM.

4. PROJECTED RATE IMPACT

Q HAS ALABAMA POWER QUANTIFIED THE POTENTIAL IMPACT OF ITS PROPOSED CAPACITY ADDITIONS ON RATES?

A Yes. APC witness, Ms. Christine Baker, projects that the proposed capacity additions would equate to an increase of about $4 per month for a typical residential customer.[18]

Q WERE YOU ABLE TO VALIDATE MS. BAKER'S PROJECTED RESIDENTIAL RATE IMPACT?

A No. APC's rate projection is entirely unsupported. First, it is based on numerous assumptions, including:

- The actual acquisition costs, investment and purchase power capacity costs do not exceed APC's current projections;
- The capacity additions operate as projected with respect to both generator output and economics (*i.e*., the assumed heat rates for the thermal plant additions);
- APC's low and medium projected natural gas prices are realized; and
- The rate mechanisms through which each of the costs would be recovered in rates (as discussed in Part 5).

As APC states that it is entitled to recover all of the costs associated with the proposed capacity additions, future rates will reflect the costs actually incurred. Any cost overruns or failure to achieve the projected output and/or the assumed prices and heat rates are higher than projected, the rate impacts will be higher than stated by Ms. Baker.

[18] *Direct Testimony of Christine M. Baker at 10.*

Second, APC could not provide detailed workpapers supporting the base rate cost components or the projected energy savings for any of the proposed capacity additions.[19]

Q DID YOU FIND ANY OTHER PROBLEMS WITH ALABAMA POWER'S TYPICAL BILL IMPACT CALCULATION?

A Yes. APC assumed that the entirety of the base rate costs would be spread relative to base revenues. This assumes that all of the projected fixed costs would be recovered in either Rate RSE or Rate CNP Part A. However, as discussed later, APC is proposing to recover certain plant costs through Rate CNP Part A and purchased power capacity costs through Rate CNP Part B. It is my understanding that, unless otherwise authorized by the Commission, Rate CNP Part A costs are spread on a kilowatt-hour (kWh) basis. Further, Rate CNP Part B costs are similarly spread to individual rates on a per-kWh basis. Thus, APC's projected rate impact is not consistent with its cost recovery proposal.

Q SHOULD THE COMMISSION APPROVE THE PROPOSED CERTIFICATES OF CONVENIENCE AND NECESSITY BASED ON ALABAMA POWER'S REPRESENTATIONS ABOUT FUTURE RATE IMPACTS?

A No. In addition to the many assumptions and concerns addressed above, it is important to note that the capacity additions are not the only factors that will affect future rates.

[19] *APC Response to AIEC DR-3 Interrogatory No. 40.*

5. COST RECOVERY

Q HOW IS ALABAMA POWER PROPOSING TO RECOVER THE COSTS OF THE PROPOSED CAPACITY ADDITIONS IN ITS ELECTRIC RATES?

A Table 4 below summarizes the specific cost recovery mechanisms through which APC is proposing to recover the costs of each of the proposed capacity additions.

Table 4
APC's Proposed Cost Recovery Mechanisms

Description	Fixed Costs	Compliance Costs	Fuel Costs
Hog Bayou PPA*	CNP-B Imputed Equity: RSE	N/A	ECR
Central Alabama Generating Station	RSE: Closing – May 2023 CNP-A Jun 2023 RSE Jan 2024	CNP-C	ECR
Barry Unit 8 CCGT	CNP-A Jan 2024 RSE Jan 2025	CNP-C	ECR
Anniston Solar, LLC **Al Solar C, LLC** **Dallas County Solar** **Dothan Solar** **Talladega County Solar**	CNP-B: 38% of Energy Payments; RSE: Interconnection Costs	N/A	ECR: 72% of Energy Payments

Source: Direct Testimony of Christine M. Baker.

Q DO YOU HAVE ANY CONCERNS ABOUT ALABAMA POWER'S COST RECOVERY PROPOSALS?

A Yes. I have three concerns. First, only the actual out-of-pocket expenses associated with the PPAs should be recovered in rates. APC is proposing to include imputed equity associated with the PPAs in Rate RSE. However, imputed equity is not an out-of-pocket expense. Second, there is no reason to use CNP-Part A to temporarily recover the costs associated with either Central Alabama or Barry Unit 8. Third, the APSC should not approve APC's Central Alabama acquisition without additional evidence that the purchase price, which includes a substantial acquisition adjustment, is reasonable and appropriate.

Q WHY IS IT INAPPROPRIATE TO INCLUDE IMPUTED EQUITY AS AN ADDITIONAL COST ASSOCIATED WITH THE HOG BAYOU POWER PURCHASE AGREEMENT?

A Imputed equity is not an out-of-pocket expense. It is an adjustment to a utility's capital structure that the credit rating agencies make to recognize the debt-like obligation it undertakes under a PPA. If the APSC approves the Hog Bayou PPA, APC will incur a fixed Demand charge of $[redacted] per kW-Yr., escalating at [redacted]% per year. This fixed Demand charge will be recognized by the credit rating agencies as long-term debt. Consequently, it will adjust APC's debt-to-equity ratio in assessing APC's credit worthiness.

Q WHY ELSE IS IT UNNECESSARY TO INCLUDE IMPUTED EQUITY IN RATE RSE?

A First, the credit rating agencies currently recognize imputed equity for APC's fixed obligations under the Calhoun PPA. As previously stated, the Calhoun PPA will expire at the end of 2022. The Calhoun PPA fixed cost payments are substantially higher than the corresponding projected Hog Bayou payments. Thus, the expiration of the Calhoun PPA will more than offset the imputed equity associated with Hog Bayou.

Second, APC is proposing to raise its equity ratio to 55% by the end of 2025.[20]

[20] *Revisions to Rate RSE (Rate Stabilization and Equalization), Docket Nos. 18117 and 18416 at 5 (Apr. 17, 2018).*

This will provide a more than ample cushion to absorb the fixed cost obligation under the Hog Bayou PPA. Accordingly, APC's proposal to include imputed equity associated with the Hog Bayou PPA should be rejected.

Q WHY DO YOU DISAGREE WITH ALABAMA POWER'S PROPOSAL TO USE CNP-PART A TO TEMPORARILY RECOVER THE CENTRAL ALABAMA AND BARRY UNIT 8 INVESTMENTS?

A CNP-Part A was implemented prior to when Rate RSE was changed from a historical to a forward-looking test year. Hence, the projected costs of new capacity additions can be reflected in Rate RSE.

Q IS ALABAMA POWER PROPOSING TO USE RATE RSE TO INITIALLY RECOVER THE CENTRAL ALABAMA INVESTMENT?

A Yes. Assuming that the Commission approves the CCN, APC is proposing to include the non-fuel related costs of the Central Alabama acquisition in Rate RSE from the closing date until the station begins serving APC customers in June 2023. Thus, there is no need to move the Central Alabama costs from Rate RSE to Rate CNP Part A. Further, because the expiration date is known, APC can adjust its RSE projections to recognize that the revenues it will receive from the Central Alabama acquisition from the closing date through May 2023 will cease.

Q IS THERE ANY COMPELLING NEED TO USE RATE CNP PART A TO RECOVER THE COSTS OF BARRY UNIT 8?

A No. Barry Unit 8 is scheduled to commence service in November 2023. Under the terms of Rate CNP Part A, cost recovery would commence within two calendar months, or January 2024. There is no reason why APC cannot easily incorporate

Barry Unit 8 in its 2024 RSE projections. When the RSE projections are made, the investment in Barry Unit 8 will be known and measurable. The corresponding non-fuel operating expenses will also be included in APC's 2024 RSE projections. There is no reason to recover any portion of these costs in Rate CNP Part A.

Q WHAT IS AN ACQUISITION ADJUSTMENT?

A An acquisition adjustment occurs when the purchase price exceeds the net book value of the plant.

Q IS ALABAMA POWER SEEKING RECOVERY OF AN ACQUISITION ADJUSTMENT FOR ITS PROPOSED CENTRAL ALABAMA GENERATING STATION PURCHASE?

A Yes. APC states that it will pay $[redacted] million to acquire Central Alabama. However, it projects that Central Alabama will have a $[redacted] million net book value assuming the acquisition is closed on July 1, 2020. This will result in an estimated acquisition adjustment of $[redacted] million.[21]

Q IS THERE ANY DISCUSSION OF THE ACQUISITION ADJUSTMENT IN THE FILED PETITION?

A No.

Q SHOULD ALABAMA POWER BE REQUIRED TO PROVIDE ADDITIONAL EVIDENCE SUPPORTING THE ACQUISITION ADJUSTMENT FOR CENTRAL ALABAMA?

A Yes. The Commission should not approve a CCN or allow cost recovery for the

[21] *APC Response to AIEC DR-2 I-23*

Central Alabama acquisition without receiving further evidence that the proposed acquisition adjustment is reasonable.

Q IS IT NECESSARY TO AUTHORIZE RECOVERY OF FIXED AND IMPUTED CAPACITY PAYMENTS PURSUANT TO LONG-TERM PURCHASED POWER AGREEMENTS THROUGH RATE CNP PART B?

A No. With the use of a forward-looking test year in Rate RSE, it is no longer necessary to recover capacity payments under any of the proposed long-term PPAs through Rate CNP Part B. As with Part A, Rate CNP Part B was established at a time when Rate RSE used a historical test year. Hence, cost recovery was necessary to minimize regulatory lag. This objective is accomplished by authorizing cost recovery through Rate RSE.

Q SHOULD THE STATUS QUO BE MAINTAINED FOR ANY PURCHASED CAPACITY COSTS THAT ARE CURRENTLY BEING RECOVERED IN RATE CNP PART B?

A The capacity payments associated with PPAs that will expire prior to 2023 should remain in Rate CNP Part B.

Q ALABAMA POWER IS PROPOSING TO RECOVER 38% OF THE PAYMENTS ASSOCIATED WITH THE PROPOSED SOLAR/BATTERY ENERGY STORAGE PROJECTS THROUGH RATE CNP PART B. WHAT IS THE BASIS FOR THE 38%?

A APC has determined that 38% of the combined energy payments associated with the Solar/BESS PPAs are reasonably attributable to the cost of the BESS. The BESS is essential in APC's assessment that the proposed solar projects will provide capacity and that this capacity can be included in determining APC's resource adequacy and reserve margins. Hence, APC is proposing that these "imputed" capacity payments be recovered in Rate CNP Part B rather than in Rate ECR.

Q IS THERE ANY MERIT TO AUTHORIZING RECOVERY OF IMPUTED CAPACITY COSTS THROUGH A DIFFERENT COST RECOVERY MECHANISM?

A Yes. Conceptually, there is merit to authorizing recovery of imputed capacity costs through a different cost recovery mechanism provided that they are allocated on a peak demand basis. As previously stated, capacity payments recovered in Rate CNP Part B is spread to all customer classes on a kWh basis. This is similar to how fuel and purchased energy costs are recovered in Rate ECR, except that the latter rate properly recognizes the differences in loss factors.

Q IS THERE ANY CONCEPTUAL DIFFERENCE BETWEEN THE BESS COSTS AND A PORTION OF THE ENERGY PAYMENTS UNDER THE CURRENTLY EFFECTIVE WIND PURCHASED POWER AGREEMENTS?

A No. The combined energy payments under the currently effective Buffalo Dunes and Chisholm View wind PPAs are being recovered in Rate ECR. However, despite recognizing that these long-term wind contracts also provide capacity value, APC does not recognize any imputed capacity costs under the wind PPAs provide.

Q SHOULD THE COMMISSION APPROVE ALABAMA POWER'S PROPOSAL TO RECOVER BESS PAYMENTS IN RATE CNP PART B?

A No. As previously recommended, these costs should be recovered in Rate RSE along with the non-fuel related costs associated with APC's other proposed capacity additions. However, if the APSC rejects my recommendation, the BESS costs should be recovered in Rate ECR consistent with how the imputed capacity payments for the wind PPAs are being recovered.

6. CONCLUSION

Q WHAT FINDINGS SHOULD THE COMMISSION MAKE BASED ON YOUR TESTIMONY?

A The APSC should make the following findings:

- APC does not need to add new capacity until [redacted]. Prior to [redacted], APC can make Reserve Equalization purchases under the IIC to satisfy its capacity obligations.
- Deny the proposed CCNs unless the Commission finds that additional capacity is needed to replace the capacity associated with the expiring Calhoun PPA.
- Approve seasonal planning but defer any decision establishing a specific system and diversified long-term winter TRM until after further discussions between APC, the Commission Staff and interested parties, and APC is able to make necessary refinements to the 2018 RMS.
- Order APC to provide in-depth documentation for the projected rate impacts associated with the proposed CCNs.
- Deny recovery of imputed equity associated with the Hog Bayou PPA (if a CCN is approved).
- Require that the fixed and imputed capacity payments for any long-term PPAs that receive CCNs be recovered in Rate RSE.
- Authorize recovery of all fixed costs associated with the Central Alabama acquisition and Barry Unit 8 in Rate RSE if CCNs are approved.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes.

APPENDIX A

Qualifications of Jeffry Pollock

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jeffry Pollock. My business mailing address is 12647 Olive Blvd., Suite 585, St. Louis, Missouri 63141.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am an energy advisor and President of J. Pollock, Incorporated (J. Pollock).

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor of Science Degree in Electrical Engineering and a Master's Degree in Business Administration from Washington University. I have also completed a Utility Finance and Accounting course.

Upon graduation in June 1975, I joined Drazen-Brubaker & Associates, Inc. (DBA). DBA was incorporated in 1972 assuming the utility rate and economic consulting activities of Drazen Associates, Inc., active since 1937. From April 1995 to November 2004, I was a managing principal at Brubaker & Associates (BAI).

During my career, I have been engaged in a wide range of consulting assignments including energy and regulatory matters in both the United States and several Canadian provinces. This includes preparing financial and economic studies of investor-owned, cooperative and municipal utilities on revenue requirements, cost of service and rate design, conducting site evaluations, advising clients on electric restructuring issues, assisting clients to procure and manage electricity in both competitive and regulated markets, developing and issuing requests for proposals

(RFPs), evaluating RFP responses and contract negotiation and developing and presenting seminars on electricity issues.

I have worked on various projects in 28 states and several Canadian provinces, and have testified before the Federal Energy Regulatory Commission, the Ontario Energy Board, and the state regulatory commissions of Alabama, Arizona, Arkansas, Colorado, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, New Jersey, New Mexico, New York, Ohio, Pennsylvania, South Carolina, Texas, Virginia, Washington, and Wyoming. I have also appeared before the City of Austin Electric Utility Commission, the Board of Public Utilities of Kansas City, Kansas, the Board of Directors of the South Carolina Public Service Authority (a.k.a. Santee Cooper), the Bonneville Power Administration, Travis County (Texas) District Court, and the U.S. Federal District Court.

Q PLEASE DESCRIBE J. POLLOCK, INCORPORATED.

A J. Pollock assists clients to procure and manage energy in both regulated and competitive markets. The J. Pollock team also advises clients on energy and regulatory issues. Our clients include commercial, industrial and institutional energy consumers. J. Pollock is a registered Class I aggregator in the State of Texas.

Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidential Permian Ltd.	19-00170-UT	Direct	NM	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	11/22/2019
GEORGIA POWER COMPANY	Georgia Association of Manufacturers and Georgia Industrial Group	42516	Direct	GA	Return on Equity; Capital Structure; Coal Combustion Residuals Recovery; Class Revenue Allocation; Rate Design	10/17/2019
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	19-E-0378 / 19-G-0379 19-E-0380 / 19-G-0381	Rebuttal	NY	Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design	10/15/2019
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	19-E-0378 / 19-G-0379 19-E-0380 / 19-G-0381	Direct	NY	Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design; Amortization of Regulatory Liabilties; AMI Cost Allocation	9/20/2019
AEP TEXAS INC.	Texas Industrial Energy Consumers	49494	Cross-Rebuttal	TX	ERCOT 4CPs; Class Revenue Allocation; Customer Support Costs	8/13/2019
AEP TEXAS INC.	Texas Industrial Energy Consumers	49494	Direct	TX	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; Transmission Line Extensions	7/25/2019
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	49421	Cross-Rebuttal	TX	Class Cost-of-Service Study	6/19/2019
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	49421	Direct	TX	Class Cost-of-Service Study; Rate Design; Transmission Service Facilities Extensions	6/6/2019
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	48973	Direct	TX	Prudence of Solar PPAs, Imputed Capacity, treatment of margins from Off-System Sales	5/21/2019
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	20322	Rebuttal	MI	Classification of Distribution Mains; Allocation of Working Gas in Storage and Storage	4/29/2019
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	20322	Direct	MI	Class Cost-of-Service Study; Transportation Rate Design	4/5/2019
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	49042	Cross-Rebuttal	TX	Transmsision Cost Recovery Factor	3/21/2019
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	49057	Direct	TX	Transmsision Cost Recovery Factor	3/18/2019
DUKE ENERGY PROGRESS, LLC	Nucor Steel - South Carolina	2018-318-E	Direct	SC	Class Cost-of-Service Study, Class Revenue Allocation, LGS Rate Design, Depreciation Expense	3/4/2019
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	18-037	Settlement	AR	Testimony in Support of Settlement	3/1/2019
ENERGY+ INC.	Toyota Motor Manufacturing Canada	EB-2018-0028	Updated Evidence	ON	Class Cost-of-Service Study, Distribution and Standby Distribution Rate Design	2/15/2019
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	18-037	Surrebuttal	AR	Solar Energy Purchase Option Tariff	2/14/2019

Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	48847	Direct	TX	Fuel Factor Formulas	1/11/2019
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	18-037	Direct	AR	Solar Energy Purchase Option Tariff	1/10/2019
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	20165	Direct	MI	Integrated Resources Plan; Projected Rate Impact, Risk Assessment; Early Retirement of Coal Units; Financial Compensation Mechanism	10/15/2018
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	20134	Rebuttal	MI	Class Cost-of-Service Study; Average Historical Profile; Distribution Cost Classification and Allocation; Rate Design	10/1/2018
ENERGY+ INC.	Toyota Motor Manufacturing Canada	EB-2018-0028	Initial Evidence	ON	Class Cost-of-Service Study, Distribution and Standby Distribution Rate Design	9/27/2018
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	20134	Direct	MI	Investment Recovery Mechanism, Litigation surcharge, Class Cost-of-Service Study, Class Revenue Allocation, Rate Design	9/10/2018
KANSAS GAS AND ELECTRIC COMPANY	Occidental Chemical Corporation	18-KG&E-303-CON	Rebuttal	KS	Benefits of the Interruptible Load Provided in the Special Contract	8/29/2018
TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	48401	Cross-Rebuttal	TX	4CP Moderation Adjustment	8/28/2018
ENTERGY TEXAS, INC.	Texas Indusrial Energy Consumers	48371	Cross-Rebuttal	TX	Class Cost-of-Service Study; Schedule FERC	8/16/2018
TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	48401	Direct	TX	Tax Cuts and Jobs Act; Rider TCRF; 4CP Moderation Adjustment	8/13/2018
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2018-3000164	Surrebuttal	PA	Post Test-Year Adjustment; Tax Cuts and Jobs Act; Class Cost-of-Service Study; Distribution System Improvement Charge	8/8/2018
ENTERGY TEXAS, INC.	Texas Indusrial Energy Consumers	48371	Direct	TX	Revenue Requirements; Tax Cuts and Jobs Act; Riders	8/1/2018
ENTERGY TEXAS, INC.	Texas Indusrial Energy Consumers	48371	Direct	TX	Class Cost-of-Service Study; Firm, Interruptible and Standby Rate Design	8/1/2018
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2018-3000164	Rebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation	7/24/2018
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Indusrial Energy Consumers	48233	Cross-Rebuttal	TX	Allocation of TCJA reduction	7/19/2018
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Indusrial Energy Consumers	48233	Direct	TX	Allocation of TCJA reduction	7/5/2018
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2018-3000164	Direct	PA	Post Test-Year Adjustment; Tax Cuts and Jobs Act; Class Cost-of-Service Study; Class Revenue Allocation	6/26/2018

Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Indusrial Energy Consumers	47527	Cross-Rebuttal	TX	Class Cost-of-Service Study; Revenue Allocation	5/22/2018
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	17-00255-UT	Rebuttal	NM	Class Cost-of-Service Study; Revenue Allocation	5/2/2018
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	17-041	Stipulation	AR	Support of Stipulation	4/27/2018
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Indusrial Energy Consumers	47527	Direct	TX	Present Base Revenues Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	4/25/2018
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Indusrial Energy Consumers	47527	Direct	TX	Tax Cuts and Jobs Act; SPP Transmission and Wheeling Costs; Depreciation Rate; LLPPAs; Imputed Capacity; Off-System Sales Margins	4/25/2018
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	17-00255-UT	Direct	NM	Class Cost-of-Service Study; Revenue Requirements; Revenue Allocation	4/13/2018
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	17-041	Surrebuttal	AR	Certificate of Convenience and Necessity	4/6/2018
METROPOLITAN EDISON COMPANY; PENNSYLVANIA ELECTRIC COMPANY, PENNSYLVANIA POWER COMPANY AND WEST PENN POWER COMPANY	MEIUG, PICA and WPPII	2017-2637855 2017-2637857 2017-2637858 2017-2637866	Rebuttal	PA	Recovery of NITS Charges	3/22/2018
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Indusrial Energy Consumers	46936	2nd Supplemental Direct	TX	Support of Stipulation	3/2/2018
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	18424	Direct	MI	Class Cost of Service	2/28/2018
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	17-041	Direct	AR	Certificate of Convenience and Necessity	2/23/2018
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Indusrial Energy Consumers	47553	Direct	TX	Off-System Sales Margins; Renewable Energy Credits	2/20/2018
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Indusrial Energy Consumers	47461	2nd Supplemental Direct	TX	Certificate of Convenience and Necessity	2/7/2018
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Indusrial Energy Consumers	47461	Supplemental Direct	TX	Certificate of Convenience and Necessity	1/4/2018
CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenors	17-E-0459/G-0460	Rebuttal	NY	Electric and Gas Embedded Class Cost of Service; Class Revenue Allocation; Gas Rate Design; Revenue Decoupling Mechanism	12/18/2017
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	17-00044-UT	Supplemental Direct	NM	Support of Unanimous Comprehensive Stipulation	12/11/2017
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Indusrial Energy Consumers	47461	Direct	TX	Certificate of Convenience and Necessity	12/4/2017

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CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenors	17-E-0459/G-0460	Direct	NY	Electric and Gas Embedded Class Cost of Service; Class Revenue Allocation; Customer Charges; Revenue Decoupling Mechanism; Carbon Program and EAM	11/21/2017
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	17-00044-UT	Direct	NM	Certificate of Convenience and Necessity	10/24/2017
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Indusrial Energy Consumers	46936	Cross-Rebuttal	TX	Certificate of Convenience and Necessity	10/23/2017
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Indusrial Energy Consumers	46936	Supplemental Direct	TX	Certificate of Convenience and Necessity	10/6/2017
KENTUCKY POWER COMPANY	Kentucky League of Cities	2017-00179	Direct	KY	Class Cost-of-Service Study; Class Revenue Allocation	10/3/2017
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Indusrial Energy Consumers	46936	Direct	TX	Certificate of Convenience and Necessity	10/2/2017
NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	17-E-0238 / 17-G-0239	Rebuttal	NY	Electric/Gas Embedded Class Cost of Service; Class Revenue Allocation; Electric/Gas Rate Design	9/15/2017
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	18322	Rebuttal	MI	Class Cost-of-Service Study, Rate Design	9/7/2017
PENNSYLVANIA-AMERICAN WATER COMPANY	Pennsylvania-American Water Large Users Group	R-2017-2595853	Rebuttal	PA	Rate Design	8/31/2017
NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	17-E-0238 / 17-G-0239	Direct	NY	Electric/Gas Embedded Class Cost of Service; Class Revenue Allocation; Electric/Gas Rate Design, Electric/Gas Rate Modifiers, AMI Cost Allocation	8/25/2017
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	18322	Direct	MI	Revenue Requirement, Class Cost-of-Service Study, Rate Design	8/10/2017
FLORIDA POWER & LIGHT COMPANY, DUKE ENERGY FLORIDA, LLC, AND TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	170057	Direct	FL	Fuel Hedging Practices	8/10/2017
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	46449	Cross-Rebuttal	TX	Class Revenue Allocation and Rate Design	5/19/2017
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	46449	Direct	TX	Revenue Requirement, Class Cost-of-Service Study, Class Revenue Allocation and Rate Design	4/25/2017
KENTUCKY UTILITIES COMPANY	Kentucky League of Cities	2016-00370	Supplemental Direct	KY	Class Cost-of-Service Study; Class Revenue Allocation	4/14/2017
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	46416	Direct	TX	Certificate of Convenience and Necessity - Montgomery County Power Station	3/31/2017

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UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
SHARYLAND UTILITIES, L.P.	Texas Industrial Energy Consumers	45414	Cross-Rebuttal	TX	Cost Allocation Issues; Class Revenue Allocation	3/16/2017
ENTERGY LOUISIANA, LLC	Occidental Chemical Corporation	U-34283	Direct*	LA	Approval to Construct Lake Charles Power Station	3/13/2017
LOUISVILLE GAS AND ELECTRIC COMPANY	Louisville/Jefferson Metro Government	2016-00371	Direct	KY	Revenue Requirement Issues; Class Cost-of-Service Study Electric/Gas; Class Revenue Allocation Electric/Gas	3/3/2017
KENTUCKY UTILITIES COMPANY	Kentucky League of Cities	2016-00370	Direct	KY	Revenue Requirement Issues; Class Cost-of-Service Study; Class Revenue Allocation	3/3/2017
SHARYLAND UTILITIES, L.P.	Texas Industrial Energy Consumers	45414	Direct	TX	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; TCRF Allocation Factors; McAllen Division Deferrals	2/28/2017
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	46025	Direct	TX	Long-Term Purchased Power Agreements	12/12/2016
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	15-826	Surrebuttal	MN	Settlement, Cost-of-Service Study, Class Revenue Allocation, Interruptible Rates, Renew-A-Source	10/18/2016
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	15-826	Rebutal	MN	Class Cost-of-Service Study, Class Revenue Allocation	9/23/2016
VICTORY ELECTRIC COOPERATION ASSOCIATION, INC.	Westerrn Kansas Industrial Electric Consumers	16-VICE-494-TAR	Surrebuttal	KS	Formula-Based Rate Plan	9/22/2016
NATIONAL FUEL GAS DISTRIBUTION CORPORATION	Multiple Intervenors	16-G-0257	Rebuttal	NY	Embedded Class Cost of Service; Class Revenue Allocation; Rate Design	9/16/2016
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	45524	Cross-Rebuttal	TX	Class Cost-of-Service Study;	9/7/2016
METROPOLITAN EDISON COMPANY; PENNSYLVANIA ELECTRIC COMPANY AND WEST PENN POWER	MEIUG, PICA and WPPII	2016-2537349 2016-2537352 2016-2537359	Surrebuttal	PA	Post-Test Year Sales Adjustment; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	8/31/2016
VICTORY ELECTRIC COOPERATION ASSOCIATION, INC.	Westerrn Kansas Industrial Electric Consumers	16-VICE-494-TAR	Direct	KS	Formula-Based Rate Plan	8/30/2016
WESTERN COOPERATIVE ELECTRIC ASSOCIATION, INC.	Westerrn Kansas Industrial Electric Consumers	16-WSTE-496-TAR	Direct	KS	Formula-Based Rate Plan and Debt Service Payments	8/30/2016
NATIONAL FUEL GAS DISTRIBUTION CORPORATION	Multiple Intervenors	16-G-0257	Direct	NY	Embedded Class Cost of Service; Class Revenue Allocation; Rate Design	8/26/2016

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METROPOLITAN EDISON COMPANY; PENNSYLVANIA ELECTRIC COMPANY AND WEST PENN POWER	MEIUG, PICA and WPPII	2016-2537349 2016-2537352 2016-2537359	Rebuttal	PA	Class Cost-of-Service; Class Revenue Allocation	8/17/2016
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	45524	Direct	TX	Revenue Requirement; Class Cost-of-Service; Revenue Allocation; Rate Design	8/16/2016
METROPOLITAN EDISON COMPANY; PENNSYLVANIA ELECTRIC COMPANY AND WEST PENN POWER	MEIUG, PICA and WPPII	2016-2537349 2016-2537352 2016-2537359	Direct	PA	Post-Test Year Sales Adjustment; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	7/22/2016
FLORIDA POWER & LIGHT COMPANY	Florida Industrial Power Users Group	160021	DIrect	FL	Multi-Year Rate Plan, Construction Work in Progress; Cost of Capital; Class Revenue Allocation; Class Cost-of-Service Study; Rate Design	7/7/2016
CENTERPOINT ENERGY ARKANSAS GAS	Arkansas Gas Consumers, Inc.	15-098-U	Supplemental	AR	Support for Settlement Stipulation	7/1/2016
MIDAMERICAN ENERGY COMPANY	Tech Customers	RPU-2016-0001	Direct	IA	Application of Advanced Ratemaking Principles to Wind XI	6/21/2016
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	15-826	Direct	MN	Class Cost-of-Service Study, Class Revenue Allocation, Multi-Year Rate Plan, Rate Design	6/14/2016
CENTERPOINT ENERGY ARKANSAS GAS	Arkansas Gas Consumers, Inc.	15-098-U	Surrebuttal	AR	Incentive Compensation, Class Cost-of-Service Study, Class Revenue Allocation, LCS-1 Rate Design	6/7/2016
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	15-00296-UT	Direct	NM	Support of Stipulation	5/13/2016
CHEYENNE LIGHT, FUEL AND POWER COMPANY	Dyno Nobel, Inc. and HollyFrontier Cheyenne Refining LLC	20003-146-ET-15	Cross	WY	Large Power Contract Service Tariff	4/15/2016
CENTERPOINT ENERGY ARKANSAS GAS	Arkansas Gas Consumers, Inc.	15-098-U	Direct	AR	Incentive Compensation, Class Cost-of-Service Study, Class Revenue Allocation, Act 725, Formula Rate Plan	4/14/2016
CHEYENNE LIGHT, FUEL AND POWER COMPANY	Dyno Nobel, Inc. and HollyFrontier Cheyenne Refining LLC	20003-146-ET-15	Direct	WY	Large Power Contract Service Tariff	3/18/2016
ENTERGY LOUISIANA, LLC, ENTERGY GULF STATES LOUISIANA, L.L.C., AND ENTERGY LOUISIANA POWER, LLC	Occidental Chemical Corporation	U-33770	Cross-Answering	LA	Approval to Construct St. Charles Power Station	2/26/2016
NORTHERN INDIANA PUBLIC SERVICE COMPANY	NLMK-Indiana	44688	Cross-Answering	IN	Cost-of-Service Study, Rider 775	2/16/2016
ENTERGY LOUISIANA, LLC, ENTERGY GULF STATES LOUISIANA, L.L.C., AND ENTERGY LOUISIANA POWER, LLC	Occidental Chemical Corporation	U-33770	Direct	LA	Approval to Construct St. Charles Power Station	1/21/2016
EL PASO ELECTRIC COMPANY	Freeport-McMoRan Copper & Gold, Inc.	44941	Cross-Rebuttal	TX	Class Cost-of-Service Study, Class Revenue Allocation; Rate Design	1/15/2016
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	15-015	Supplemental	AR	Support for Settlement Stipulation	12/31/2015

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EL PASO ELECTRIC COMPANY	Freeport-McMoRan Copper & Gold, Inc.	44941	Direct	TX	Class Cost-of-Service Study, Class Revenue Allocation; Rate Design	12/11/2015
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	15-015	Surrebuttal	AR	Post-Test-Year Additions; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; Riders; Formula Rate Plan	11/24/2015
MID-KANSAS ELECTRIC COMPANY, LLC, PRAIRIE LAND ELECTRIC COOPERATIVE, INC., SOUTHERN PIONEER ELECTRIC COMPANY, THE VICTORY ELECTRIC COOPERATIVE ASSOCIATION, INC., AND WESTERN COOPERATIVE ELECTRIC ASSOCIATION, INC.	Western Kansas Industrial Electric Consumers	16-MKEE-023	Direct	KS	Formula Rate Plan for Distribution Utility	11/17/2015
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	45084	Direct	TX	Transmission Cost Recovery Factor Revenue Increase.	11/17/2015
GEORGIA POWER COMPANY	Georgia Industrial Group and Georgia Assocation of Manufacturers	39638	Direct	GA	Natural Gas Price Assumptions, IFR Mechanism, Seasonal FCR-24 Rates, Imputed Capacity	11/4/2015
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	15-E-0283 15-G-0284 15-E-0285 15-G-0286	Rebuttal	NY	Electric and Gas Embedded Class Cost-of-Service Studies, Class Revenue Allocation	10/13/2015
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	15-015	Direct	AR	Post-Test-Year Additions; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; Riders; Formula Rate Plan	9/29/2015
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	15-E-0283 15-G-0284 15-E-0285 15-G-0286	Direct	NY	Electric and Gas Embedded Class Cost-of-Service Studies, Class Revenue Allocation, Electric Rate Design	9/15/2015
SHARYLAND UTILITIES	Texas Industrial Energy Consumers	44620	Cross-Rebuttal	TX	Transmission Cost Recovery Factor Class Allocation Factors.	9/8/2015
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	14-118	Surrebuttal	AR	Proposed Acquisition of Union Power Station Power Block 2 and Cost Recovery	8/21/2015
SHARYLAND UTILITIES	Texas Industrial Energy Consumers	44620	Direct	TX	Transmission Cost Recovery Factor Class Allocation Factors	8/7/2015
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2015-2468981	Surrebuttal	PA	Class Cost-of-Service, Capacity Reservation Rider	8/4/2015
WESTAR ENERGY INC. and KANSAS GAS & ELECTRIC CO.	Occidental Chemical Corporation	15-WSEE-115-RTS	Cross-Answering	KS	Class Cost-of-Service Study, Revenue Allocation	7/22/2015

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PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2015-2468981	Rebuttal	PA	Class Cost-of-Service, Class Revenue Allocation, Rate Design, Capacity Reservation Rider, Revenue Deoupling	7/21/2015
SOUTHWEST ERN PUBLIC SERVICE COMPANY	Occidental Periman Ltd.	15-00083	Direct	NM	Long-Term Purchased Power Agreements	7/10/2015
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	15-014	Surrebuttal	AR	Solar Power Purchase Agreement	7/10/2015
WESTAR ENERGY INC. and KANSAS GAS & ELECTRIC CO.	Occidental Chemical Corporation	15-WSEE-115-RTS	Direct	KS	Class Cost-of-Service and Electric Distrbution Grid Resiliency Program	7/9/2015
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	43958	Supplemental DIrect	TX	Certificiate of Need for Union Power Station Power Block 1	7/7/2015
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	14-118	Direct	AR	Proposed Acquisition of Union Power Station Power Block 2 and Cost Recovery	7/2/2015
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2015-2468981	Direct	PA	Class Cost-of-Service, Class Revenue Allocation, Rate Design, Capacity Reservation Rider	6/23/2015
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	15-014-U	Direct	AR	Solar Power Purchase Agreement	6/19/2015
FLORIDA POWER & LIGHT COMPANY	Florida Industrial Power Users Group	150075	Direct	FL	Cedar Bay Power Purchase Agreement	6/8/2015
SOUTHWEST ERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	43695	Cross-Rebuttal	TX	Class Cost of Service Study; Class Revenue Allocation	6/8/2015
FLORIDA POWER AND LIGHT COMPANY, DUKE ENERGY FLORIDA, GULF POWER COMPANY, TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	140226	Surrebuttal	FL	Opt-Out Provision	5/20/2015
SOUTHWEST ERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	43695	Direct	TX	Post-Test Year Adjustments; Weather Normalization	5/15/2015
SOUTHWEST ERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	43695	Direct	TX	Class Cost of Service Study; Class Revenue Allocation	5/15/2015
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	43958	Direct	TX	Certificiate of Need for Union Power Station Power Block 1	4/29/2015
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	42370	Cross-Rebuttal	TX	Allocation and recovery of Municipal Rate Case Expenses and the proposed Rate-Case-Expense Surcharge Tariff.	1/27/2015
WEST PENN POWER COMPANY	West Penn Power Industrial Intervenors	2014-2428742	Surrebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider	1/6/2015

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PENNSYLVANIA ELECTRIC COMPANY	Penelec Industrial Customer Alliance	2014-2428743	Surrebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider	1/6/2015
METROPOLITAN EDISON COMPANY	Med-Ed Industrial Users Group	2014-2428745	Surrebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider	1/6/2015
WEST PENN POWER COMPANY	West Penn Power Industrial Intervenors	2014-2428742	Rebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider	12/18/2014
PENNSYLVANIA ELECTRIC COMPANY	Penelec Industrial Customer Alliance	2014-2428743	Rebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider	12/18/2014
METROPOLITAN EDISON COMPANY	Med-Ed Industrial Users Group	2014-2428745	Rebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider	12/18/2014
PUBLIC SERVICE COMPANY OF COLORADO	Colorado Healthcare Electric Coordinating Council	14AL-0660E	Cross	CO	Clean Air Clean Jobs Act Rider; Transmission Cost Adjustment	12/17/2014
WEST PENN POWER COMPANY	West Penn Power Industrial Intervenors	2014-2428742	Direct	PA	Class Cost-of-Service Study; Class Revenue Allocation, Rate Design, Partial Services Rider; Storm Damage Rider	11/24/2014
PENNSYLVANIA ELECTRIC COMPANY	Penelec Industrial Customer Alliance	2014-2428743	Direct	PA	Class Cost-of-Service Study; Class Revenue Allocation, Rate Design, Partial Services Rider; Storm Damage Rider	11/24/2014
METROPOLITAN EDISON COMPANY	Med-Ed Industrial Users Group	2014-2428745	Direct	PA	Class Cost-of-Service Study; Class Revenue Allocation, Rate Design, Partial Services Rider; Storm Damage Rider	11/24/2014
CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenors	14-E-0318 / 14-G-0319	Direct	NY	Class Cost-of-Service Study; Class Revenue Allocation (Electric)	11/21/2014
PUBLIC SERVICE COMPANY OF COLORADO	Colorado Healthcare Electric Coordinating Council	14AL-0660E	Direct	CO	Clean Air Clean Jobs Act Rider; Electric Commodity Adjustment Incentive Mechanism	11/7/2014
FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	140001-E	Direct	FL	Cost-Effectiveness and Policy Issues Surrounding the Investment in Working Gas Production Facilities	9/22/2014

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UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-446-ER14	Surrebuttal	WY	Class Cost-of-Service, Rule 12 (Line Extension Policy)	9/19/2014
INDIANA MICHIGAN POWER COMPANY	I&M Industrial Group	44511	Direct	IN	Clean Energy Solar Pilot Project, Solar Power Rider and Green Power Rider	9/17/2014
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-446-ER14	Cross	WY	Class Cost-of-Service Study; Rule 12 Line Extension	9/5/2014
VARIOUS UTILITIES	Florida Industrial Power Users Group	140002-EI	Direct	FL	Energy Efficiency Cost Recovery Opt-Out Provision	9/5/2014
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E-002/GR-13-868	Surrebuttal	MN	Nuclear Depreciation Expense, Monticello EPU/LCM Project, Class Cost-of-Service Study, Class Revenue Allocation, Fuel Clause Rider Reform, Rate Design	8/4/2014
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-446-ER14	Direct	WY	Class Cost-of-Service Study, Rule 12 Line Extension	7/25/2014
DUKE ENERGY FLORIDA	NRG Florida, LP	140111 and 140110	Direct	FL	Cost-Effectiveness of Proposed Self Build Generating Projects	7/14/2014
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E-002/GR-13-868	Rebuttal	MN	Class Cost-of-Service Study, Class Revenue Allocation	7/7/2014
PPL ELECTRIC UTILITIES CORPORATION	PP&L Industrial Customer Alliance	2013-2398440	Rebuttal	PA	Energy Efficiency Cost Recovery	7/1/2014
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E-002/GR-13-868	Direct	MN	Revenue Requirements, Fuel Clause Rider, Class Cost-of-Service Study, Rate Design and Revenue Allocation	6/5/2014
PPL ELECTRIC UTILITIES CORPORATION	PP&L Industrial Customer Alliance	2013-2398440	Direct	PA	Energy Efficiency Cost Recovery	5/23/2014
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	42042	Direct	TX	Transmission Cost Recovery Factor	4/24/2014
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	41791	Cross	TX	Class Cost-of-Service Study and Rate Design	1/31/2014
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	41791	Direct	TX	Revenue Requirements, Fuel Reconciliation; Cost Allocation Issues; Rate Design Issues	1/10/2014
DUQUESNE LIGHT COMPANY	Duquesne Industrial Intervenors	R-2013-2372129	Supplemental Surrebuttal	PA	Class Cost-of-Sevice Study	12/13/2013
DUQUESNE LIGHT COMPANY	Duquesne Industrial Intervenors	R-2013-2372129	Surrebuttal	PA	Class Cost-of-Service Study; Cash Working Capital; Miscellaneous General Expense; Uncollectable Expense; Class Revenue Allocation	12/9/2013
DUQUESNE LIGHT COMPANY	Duquesne Industrial Intervenors	R-2013-2372129	Rebuttal	PA	Rate L Transmission Service; Class Revenue Allocation	11/26/2013

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UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
ENTERGY TEXAS, INC. ITC HOLDINGS CORP.	Texas Industrial Energy Consumers	41850	Direct	TX	Rate Mitigation Plan; Conditions re Transfer of Control of Ownership	11/6/2013
SHARYLAND UTILITIES	Texas Inustrial Energy Consumers and Atlas Pipeline Mid-Continent WestTex, LLC	41474	Cross-Rebuttal	TX	Customer Class Definitions; Class Revenue Allocation; Allocation of TTC costs	11/4/2013
MIDAMERICAN ENERGY COMPANY	Deere & Company	RPU-2013-0004	Surrebuttal	IA	Class Cost-of-Service Study; Class Revenue Allocation; Depreciation Surplus	11/4/2013
DUQUESNE LIGHT COMPANY	Duquesne Industrial Intervenors	R-2013-2372129	Direct	PA	Class Cost-of-Service, Class Revenue Allocations	11/1/2013
PUBLIC SERVICE ENERGY AND GAS	New Jersey Large Energy Users Coalition	EO13020155 and GO13020156	Direct	NJ	Energy Strong	10/28/2013
GEORGIA POWER COMPANY	Georgia Industrial Group and Georgia Association of Manufacturers	36989	Direct	GA	Depreciation Expense, Alternate Rate Plan, Return on Equity, Class Cost-of-Service Study, Class Revenue Allocation, Rate Design	10/18/2013
SHARYLAND UTILITIES	Texas Inustrial Energy Consumers and Atlas Pipeline Mid-Continent WestTex, LLC	41474	Direct	TX	Regulatory Asset Cost Recovery; Class Cost-of-Service Study, Class Revenue Allocation, Rate Design	10/18/2013
MIDAMERICAN ENERGY COMPANY	Deere & Company	RPU-2013-0004	Rebutal	IA	Class Cost-of-Service Study	10/1/2013
FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	130007	Direct	FL	Environmental Cost Recovery Clause	9/13/2013
MIDAMERICAN ENERGY COMPANY	Deere & Company	RPU-2013-0004	Direct	IA	Class Cost-of-Service Study, Class Revenue Allocation, Depreciation, Cost Recovery Clauses, Revenue Sharing, Revenue True-up	9/10/2013
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	12-00350-UT	Rebuttal	NM	RPS Cost Rider	9/9/2013
WESTAR ENERGY INC. and KANSAS GAS & ELECTRIC CO.	Occidental Chemical Corporation	13-WSEE-629-RTS	Cross-Answering	KS	Cost Allocation Methodology	9/5/2013
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	12-00350-UT	Direct	NM	Class Cost-of-Service Study	8/22/2013
WESTAR ENERGY INC. and KANSAS GAS & ELECTRIC CO.	Occidental Chemical Corporation	13-WSEE-629-RTS	Direct	KS	Class Revenue Allocation.	8/21/2013
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	41437	Direct	TX	Avoided Cost; Standby Rate Design	8/14/2013
MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-699	Direct	KS	Class Revenue Allocation	8/12/2013
MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-447	Supplemental	KS	Testimony in Support of Settlement	8/9/2013
MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-447	Supplemental	KS	Modification Agreement	7/24/2013

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TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	130040	Direct	FL	GSD-IS Consolidation, GSD and IS Rate Design, Class Cost-of-Service Study, Planned Outage Expense, Storm Damage Expense	7/15/2013
MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-452	Supplemental	KS	Testimony in Support of Nonunanimous Settlement	6/28/2013
JERSEY CENTRAL POWER & LIGHT COMPANY	Gerdau Ameristeel Sayreville, Inc.	ER12111052	Direct	NJ	Cost of Service Study for GT-230 KV Customers; AREP Rider	6/14/2013
MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-447	Direct	KS	Wholesale Requirements Agreement; Process for Exemption From Regulation; Conditions Required for Public Interest Finding on CCN spin-down	5/14/2013
MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-452	Cross	KS	Formula Rate Plan for Distribution Utility	5/10/2013
MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-452	Direct	KS	Formula Rate Plan for Distribution Utility	5/3/2013
ENTERGY TEXAS, INC. ITC HOLDINGS CORP.	Texas Industrial Energy Consumers	41223	Direct	TX	Public Interest of Proposed Divestiture of ETI's Transmission Business to an ITC Holdings Subsidiary	4/30/2013
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	12-961	Surrebuttal	MN	Depreciation; Used and Useful; Cost Allocation; Revenue Allocation	4/12/2013
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	12-961	Rebuttal	MN	Class Revenue Allocation.	3/25/2013
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	12-961	Direct	MN	Depreciation; Used and Useful; Property Tax; Cost Allocation; Revenue Allocation; Competitive Rate & Property Tax Riders	2/28/2013
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	38951	Second Supplemental Rebuttal	TX	Competitive Generation Service Tariff	2/1/2013
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	38951	Second Supplemental Direct	TX	Competitive Generation Service Tariff	1/11/2013
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	40443	Cross Rebuttal	TX	Cost Allocation and Rate Design	1/10/2013
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	40443	Direct	TX	Application of the Turk Plant Cost-Cap; Revenue Requirements; Class Cost-of-Service Study; Class Revenue Allocation; Industrial Rate Design	12/10/2012
FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	120015	Corrected Supplemental Rebuttal	FL	Support for Non-Unanimous Settlement	11/13/2012

Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	120015	Corrected Supplemental Direct	FL	Support for Non-Unanimous Settlement	11/13/2012
NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	12-E-0201/12-G-0202	Rebuttal	NY	Electric and Gas Class Cost-of-Service Studies.	9/25/2012
NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	12-E-0201/12-G-0202	Direct	NY	Electric and Gas Class Cost-of-Service Study; Revenue Allocation; Rate Design; Historic Demand	8/31/2012
MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	12-MKEE-650-TAR	Direct	KS	Transmission Formula Rate Plan	7/31/2012
WESTAR ENERGY INC. and KANSAS GAS & ELECTRIC CO.	Occidental Chemical Corporation	12-WSEE-651-TAR	Direct	KS	TDC Tariff	7/30/2012
FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	120015	Direct	FL	Class Cost-of-Service Study, Revenue Allocation, and Rate Design	7/2/2012
LONE STAR TRANSMISSION, LLC	Texas Industrial Energy Consumers	40020	Direct	TX	Revenue Requirement, Rider AVT	6/21/2012
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	39896	Cross	TX	Class Cost-of-Service Study, Revenue Allocation, and Rate Design	4/13/2012
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	39896	Direct	TX	Revenue Requirements, Class Cost-of-Service Study, Revenue Allocation, and Rate Design	3/27/2012
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	38951	Supplemental Rebuttal	TX	Competitive Generation Service Issues	2/24/2012
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	38951	Supplemental Direct	TX	Competitive Generation Service Issues	2/10/2012
AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	39722	Direct	TX	Carrying Charge Rate Applicable to the Additional True-Up Balance and Tax Balances	11/4/2011
GULF POWER COMPANY	Florida Industrial Power Users Group	110138-EI	Direct	FL	Cost Allocation and Storm Reserve	10/14/2011
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	39504	Direct	TX	Carrying Charge Rate Applicable to the Additional True-Up Balance and Taxes	9/12/2011
AEP TEXAS NORTH COMPANY	Texas Industrial Energy Consumers	39361	Cross-Rebuttal	TX	Energy Efficiency Cost Recovery Factor	8/10/2011
AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	39360	Cross-Rebuttal	TX	Energy Efficiency Cost Recovery Factor	8/10/2011
ONCOR ELECTRIC DELIVERY COMPANY, LLC	Texas Industrial Energy Consumers	39375	Direct	TX	Energy Efficiency Cost Recovery Factor	8/2/2011
ALABAMA POWER COMPANY	Alabama Industrial Energy Consumers	31653	Direct	AL	Renewable Purchased Power Agreement	7/28/2011
AEP TEXAS NORTH COMPANY	Texas Industrial Energy Consumers	39361	Direct	TX	Energy Efficiency Cost Recovery Factor	7/26/2011

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UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	36360	Direct	TX	Energy Efficiency Cost Recovery Factor	7/20/2011
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	39366	Direct	TX	Energy Efficiency Cost Recovery Factor	7/19/2011
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	39363	Direct	TX	Energy Efficiency Cost Recovery Factor	7/15/2011
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-10-971	Surrebuttal	MN	Depreciation; Non-Asset Margin Sharing; Step-In Increase; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	5/26/2011
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-10-971	Rebuttal	MN	Classification of Wind Investment	5/4/2011
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-10-971	Direct	MN	Surplus Depreciation Reserve, Incentive Compensation, Non-Asset Trading Margin Sharing, Cost Allocation, Class Revenue Allocation, Rate Design	4/5/2011
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-381-EA-10	Direct	WY	2010 Protocols	2/11/2011
TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	38480	Direct	TX	Cost Allocation, TCRF	11/8/2010
GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Traditional Manufacturers Group	31958	Direct	GA	Alternate Rate Plan, Return on Equity, Riders, Cost-of-Service Study, Revenue Allocation, Economic Development	10/22/2010
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	38339	Cross-Rebuttal	TX	Cost Allocation, Class Revenue Allocation	9/24/2010
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	38339	Direct	TX	Pension Expense, Surplus Depreciation Reserve, Cost Allocation, Rate Design, Riders	9/10/2010
NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	10-E-0050	Rebuttal	NY	Multi-Year Rate Plan, Cost Allocation, Revenue Allocation, Reconciliation Mechanisms, Rate Design	8/6/2010
NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	10-E-0050	Direct	NY	Multi-Year Rate Plan, Cost Allocation, Revenue Allocation, Reconciliation Mechanisms, Rate Design	7/14/2010
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	37744	Cross Rebuttal	TX	Cost Allocation, Revenue Allocation, CGS Rate Design, Interruptible Service	6/30/2010
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	37744	Direct	TX	Class Cost of Service Study, Revenue Allocation, Rate Design, Competitive Generation Services, Line Extension Policy	6/9/2010

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UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	37482	Cross Rebuttal	TX	Allocation of Purchased Power Capacity Costs	2/3/2010
GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Traditional Manufacturers Group	28945	Direct	GA	Fuel Cost Recovery	1/29/2010
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	37482	Direct	TX	Purchased Power Capacity Cost Factor	1/22/2010
VIRGINIA ELECTRIC AND POWER COMPANY	MeadWestvaco Corporation	PUE-2009-00081	Direct	VA	Allocation of DSM Costs	1/13/2010
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	37580	Direct	TX	Fuel refund	12/4/2009
VIRGINIA ELECTRIC AND POWER COMPANY	MeadWestvaco Corporation	PUE-2009-00019	Direct	VA	Standby rate design; dynamic pricing	11/9/2009
VIRGINIA ELECTRIC AND POWER COMPANY	MWV	PUE-2009-00019	Direct	VA	Base Rate Case	11/9/2009
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	37135	Direct	TX	Transmission cost recovery factor	10/22/2009
MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	09-MKEE-969-RTS	Direct	KS	Revenue requirements, TIER, rate design	10/19/2009
VARIOUS UTILITIES	Florida Industrial Power Users Group	090002-EG	Direct	FL	Interruptible Credits	10/2/2009
ONCOR ELECTRIC DELIVERY COMPANY	Texas Industrial Energy Consumers	36958	Cross Rebuttal	TX	2010 Energy efficiency cost recovery factor	8/18/2009
PROGRESS ENERGY FLORIDA	Florida Industrial Power Users Group	90079	Direct	FL	Cost-of-service study, revenue allocation, rate design, depreciation expense, capital structure	8/10/2009
CENTERPOINT	Texas Industrial Energy Consumers	36918	Cross Rebuttal	TX	Allocation of System Restoration Costs	7/17/2009
FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	080677	Direct	FL	Depreciation; class revenue allocation; rate design; cost allocation; and capital structure	7/16/2009
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	36956	Direct	TX	Approval to revise energy efficiency cost recovery factor	7/16/2009
VARIOUS UTILITIES	Florida Industrial Power Users Group	VARIOUS DOCKETS	Direct	FL	Conservation goals	7/6/2009
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	36931	Direct	TX	System restoration costs under Senate Bill 769	6/30/2009
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	36966	Direct	TX	Authority to revise fixed fuel factors	6/18/2009
TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	36025	Cross-Rebuttal	TX	Cost allocatiion, revenue allocation and rate design	6/10/2009
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	08-1065	Surrebuttal	MN	Cost allocation, revenue allocation, rate design	5/27/2009
TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	36025	Direct	TX	Cost allocation, revenue allocation, rate design	5/27/2009
VIRGINIA ELECTRIC AND POWER COMPANY	MeadWestvaco Corporation	PUE-2009-00018	Direct	VA	Transmission cost allocation and rate design	5/20/2009

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UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
NORTHERN INDIANA PUBLIC SERVICE COMPANY	Beta Steel Corporation	43526	Direct	IN	Cost allocation and rate design	5/8/2009
ENTERGY SERVICES, INC	Texas Industrial Energy Consumers	ER008-1056	Rebuttal	FERC	Rough Production Cost Equalization payments	5/7/2009
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	08-1065	Rebuttal	MN	Class revenue allocation and the classification of renewable energy costs	5/5/2009
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	08-1065	Direct	MN	Cost-of-service study, class revenue allocation, and rate design	4/7/2009
ENTERGY SERVICES, INC	Texas Industrial Energy Consumers	ER08-1056	Answer	FERC	Rough Production Cost Equalization payments	3/6/2009
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-333-ER-08	Direct	WY	Cost of service study; revenue allocation; inverted rates; revenue requirements	1/30/2009
ENTERGY SERVICES	Texas Industrial Energy Consumers	ER08-1056	Direct	FERC	Entergy's proposal seeking Commission approval to allocate Rough Production Cost Equalization payments	1/9/2009

ALABAMA POWER COMPANY

Projected Net Peak Load Growth
Versus Proposed Capacity Additions
Amounts in MW

		Winter Peak			
Line	Year	Demand	Cumulative Load Growth	Cumulative Capacity Additions	Cumulative Capacity Retirements
		(1)	(2)	(3)	(4)
1	2020	[redacted]	[redacted]	[redacted]	[redacted]
2	2021	[redacted]	[redacted]	[redacted]	[redacted]
3	2022	[redacted]	[redacted]	[redacted]	[redacted]
4	2023	[redacted]	[redacted]	[redacted]	[redacted]
5	2024	[redacted]	[redacted]	[redacted]	[redacted]
6	2025	[redacted]	[redacted]	[redacted]	[redacted]
7	2026	[redacted]	[redacted]	[redacted]	[redacted]
8	2027	[redacted]	[redacted]	[redacted]	[redacted]
9	2028	[redacted]	[redacted]	[redacted]	[redacted]
10	2029	[redacted]	[redacted]	[redacted]	[redacted]

		Summer Peak			
Line	Year	Demand	Cumulative Load Growth	Cumulative Capacity Additions	Cumulative Capacity Retirements
		(1)	(2)	(3)	(4)
11	2020	[redacted]	[redacted]	[redacted]	[redacted]
12	2021	[redacted]	[redacted]	[redacted]	[redacted]
13	2022	[redacted]	[redacted]	[redacted]	[redacted]
14	2023	[redacted]	[redacted]	[redacted]	[redacted]
15	2024	[redacted]	[redacted]	[redacted]	[redacted]
16	2025	[redacted]	[redacted]	[redacted]	[redacted]
17	2026	[redacted]	[redacted]	[redacted]	[redacted]
18	2027	[redacted]	[redacted]	[redacted]	[redacted]
19	2028	[redacted]	[redacted]	[redacted]	[redacted]
20	2029	[redacted]	[redacted]	[redacted]	[redacted]

ALABAMA POWER COMPANY
Projected Reserve Margins Based on Proposed Capacity Additions
Amounts in MW

Line	Winter	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
	Capacity Resources											
	Existing Capacity:											
1	Owned	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	Purchased	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	**Capacity Additions**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	**Capacity Retirements**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	**System Sale**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6	**DSO**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7	**Total Resources**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8	**Net Peak Demand**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9	**Reserves With Capacity Additions**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10	**Reserves Before Capacity Additions**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
11	**Reserve Margin With Capacity Additions**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
12	**Reserve Margin Before Capacity Additions**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Public Disclosure Version

ALABAMA POWER COMPANY
Projected Reserve Margins Based on Proposed Capacity Additions
Amounts in MW

Line	Summer	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
	Capacity Resources											
	Existing Capacity:											
13	Owned	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
14	Purchased	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
15	**Capacity Additions**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
16	**Capacity Retirements**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
17	**System Sale**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
18	**DSO**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
19	**Total Resources**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
20	**Net Peak Demand**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
21	**Reserves With Capacity Additions**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
22	**Reserves Before Capacity Additions**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
23	**Reserve Margin With Capacity Additions**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
24	**Reserve Margin Before Capacity Additions**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

ALABAMA POWER COMPANY
Survey of Target Reserve Margins of Investor-Owned Electric Utilities
<u>Operating in the Southeast</u>

Line	Company	Winter	Summer	Source
		(1)	(2)	(3)
1	Appalachian Power Company	N/S	15.8%	Note 1
2	Dominion Virginia Power	N/S	15.8%	Note 1
3	Duke Energy Carolinas	17.0%	N/S	Note 2
4	Duke Energy Florida	20.0%		Note 3
5	Duke Energy Kentucky	N/S	13.7%	Note 4
6	Duke Energy Progress	17.0%	N/S	Note 2
7	Entergy Arkansas	N/S	17.1%	Note 5
8	Entergy Mississippi	N/S	17.1%	Note 5
9	Florida Power & Light	20.0%		Note 3
10	Kentucky Power	N/S	15.8%	Note 1
11	Kentucky Utilities/Louisville G&E	17% - 25%		Note 6
12	South Carolina Electric & Gas	21.0%	14.0%	Note 7
13	Tampa Electric	20.0%		Note 3

N/S Not specified.

Notes:

1 PJM Installed Reserve Margin Requirement. Utility "diversified" planning reserve margins are generally lower.

2 2019 Integrated Resource Plans.

3 Utility Ten Year Site Plans.

4 2018 Integrated Resource Plan.

5 MISO Planning Reserve Margin Requirement. Utility "diversified planning reserve margins are generally lower.

6 2018 Integrated Resource Plan.

7 2019 Integrated Resource Plan. The amounts shown are "Peaking" reserves. SCE&G's "base" TRMs are 14% winter and 12% summer.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2018 Long-Term Reliability Assessment

December 2018

Key Finding 1: ERCOT, MRO-MISO, and NPCC-Ontario Are Projected to Be below the Reference Margin Level; Probabilistic Assessments of Future Conditions can Highlight Additional Reliability Challenges

Key Points:

- Anticipated Reserve Margins in TRE-ERCOT are projected below the Reference Margin Level for the entire first five-year period.
- MISO and NPCC-Ontario are projected to have Anticipated Reserve Margin shortfalls beginning in 2023.
- Probabilistic evaluations identify resource adequacy risks during nonpeak conditions in WECC-CAMX starting in 2020 and increasing by 2022.

For the majority of the BPS, planning reserve margins appear sufficient to maintain reliability during the long-term, ten-year horizon. However, there are challenges facing the electric industry that may shift industry projections and cause NERC's assessment to change. Where markets exist, signals for new capacity must be effective for planning purposes and reflect the lead times necessary to construct new generation, any requisite natural gas infrastructure, and any associated transmission. Although generating plant construction lead times have been significantly reduced, environmental permitting and pipeline and transmission planning and approval still require significant lead times.[10]

As shown in **Figure 1.1**, all assessment areas remain above the Anticipated Reference Margin Level through 2023 with the exception of ERCOT, MISO, and NPCC-Ontario.

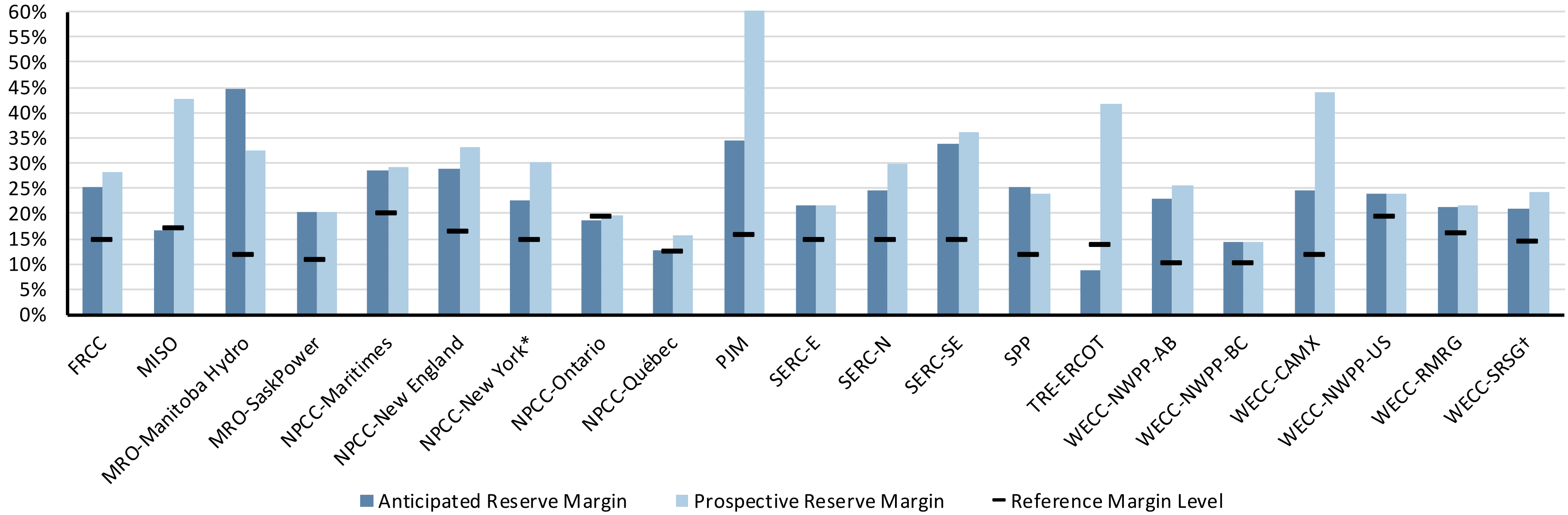

Figure 1.1: Anticipated and Prospective Reserve Margins for 2023 Peak by Assessment Area

[10] Capacity supply and planning reserve margin projections in this assessment do not necessarily take into account all generator retirements that may occur over the next 10 years or account for all replacement resources explicitly linked with potential retiring resources. While some generation plants have already announced and planned for retirement, there are still many economically vulnerable generation resources that have not determined and/or announced their plans for retirement.

As part of NERC's assessment, Table 1.1 identifies these areas as "Marginal" with all other areas identified as "Adequate" through 2023. While MISO and NPCC-Ontario show only a very small shortfall, TRE-ERCOT shows a shortfall of over 4,000 MW.

Table 1.1: NERC's Risk Determination of All Assessment Areas Five-Year Projected Reserve Margins

Assessment Area	2023 Peak Anticipated Reserve Margin	2023 Reference Margin Level	Expected Capacity Surplus or Shortfall (MW)	Assessment Result Through 2023
FRCC	25.33%	15.00%	4,868	Adequate
MRO-MISO	16.84%	17.10%	-313	**Marginal**
MRO-Manitoba	44.60%	12.00%	1,413	Adequate
MRO-SaskPower	20.29%	11.00%	369	Adequate
NPCC-Maritimes	28.45%	20.00%	443	Adequate
NPCC-New England	28.98%	16.36%	3,070	Adequate
NPCC-New York	22.74%	15.00%	2,432	Adequate
NPCC-Ontario	18.62%	19.43%	-175	**Marginal**
NPCC-Quebec	12.86%	12.61%	92	Adequate
PJM	34.53%	15.80%	27,326	Adequate
SERC-E	21.48%	15.00%	2,793	Adequate
SERC-N	24.58%	15.00%	3,861	Adequate
SERC-SE	33.77%	15.00%	8,757	Adequate
SPP	25.15%	12.00%	7,032	Adequate
TRE-ERCOT	8.62%	13.75%	-4,018	**Marginal**
WECC-AB	22.83%	10.14%	1,564	Adequate
WECC-BC	14.23%	10.14%	499	Adequate
WECC-CAMX	24.51%	12.02%	6,267	Adequate
WECC-NWPP US	23.82%	19.56%	2,138	Adequate
WECC-RMRG	21.14%	16.07%	669	Adequate
WECC-SRSG	20.90%	14.47%	1,654	Adequate