**BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS**

In the Matter of the Petition of Evergy Kansas Central, Inc., Evergy Kansas South, Inc., and Evergy Metro, Inc. for Determination of the Ratemaking Principles and Treatment that Will Apply to the Recovery in Rates of the Cost to be Incurred for Certain Electric Generation Facilities under K.S.A. 66-1239	)	**25-EKCE-207-PRE**

PUBLIC REDACTED DIRECT TESTIMONY

Redacted Testimony Identified by: **[redacted]**

PREPARED BY

JUSTIN T GRADY

UTILITIES DIVISION

KANSAS CORPORATION COMMISSION

March 14, 2025

Contents

I. Introduction, Qualifications, Purpose and Overview of Testimony

Q. Please state your name and business address.

A. My name is Justin T. Grady and my business address is 1500 Southwest Arrowhead Road, Topeka, Kansas, 66604.

Q. By whom and in what capacity are you employed?

A. I am employed by the Kansas Corporation Commission (KCC or Commission) as the Deputy Director of the Utilities Division.

Q. Please summarize your educational and employment background.

A. I earned a Master of Business Administration degree, with a concentration in General Finance which includes emphases in Corporate Finance and Investment Management, from the University of Kansas in December of 2009. I also hold a Bachelor of Business Administration degree with majors in Finance and Economics from Washburn University. I have been employed by the KCC in various positions of increasing responsibility within the Utilities Division since 2002.

From May of 2012 through August 2020 my title was Chief of Accounting and Financial Analysis. In that role I was responsible for the activities of the Commission's Audit section within the Utilities Division. In that capacity, I planned, managed, and performed audits relating to utility rate cases, surcharge filings, fuel cost recovery mechanisms, transmission delivery charges, alternative-ratemaking mechanisms, and other utility filings that would have an impact on utility rates in Kansas including mergers, acquisitions, and restructuring filings.

In August 2020 my title was changed to Chief of Revenue Requirements, Cost of Service and Finance. In this role my responsibilities expanded to include oversight of class cost of service, gas purchasing and hedging plans, and utility tariff filing reviews. In February of 2024 I was promoted to the Deputy Director of the Utilities Division. In this capacity I supervise the Chief of Accounting and Finance, as well as the Chief of Economics and Rates, and I continue to have oversight responsibility for utility tariff filings, class cost of service studies, gas purchasing and hedging activities, and Staff's review of Integrated Resource Plan (IRP) filings.

Since June of 2024 I have served as Kansas' voting member of the Cost Allocation Working Group (CAWG) at the Southwest Power Pool (SPP). As part of that responsibility, I am assigned by the Chair of the CAWG to monitor the activities of the Supply Adequacy Working Group (SAWG) and the Improved Resource Availability Task Force (IRATF) and report back to CAWG on Resource Adequacy issues which are under the authority of the Regional State Committee (RSC). In December of 2024 I was selected to serve on the newly formed SPP Demand Response Cohort team, which is evaluating and proposing a comprehensive Demand Response Policy to the Resource and Energy Adequacy Leadership team (REAL).

While employed with the Commission, I have participated in and directed the review of rate cases, general investigations, integrated resource plan filings, mergers and acquisitions, gas purchasing and hedging dockets, and various other proceedings involving electric, natural gas distribution, water distribution, and telecommunications utilities. I also frequently provide testimony and make presentations to the Kansas Legislature on public utility regulatory matters.

Q. Have you previously submitted testimony before this Commission?

A. Yes. I have submitted written and oral testimony before this Commission on multiple occasions. This work includes testimony filings in 80 dockets, including this one. A list of the other dockets that encompass this experience is readily available upon request.

Q. What is the purpose of your testimony in the review of this Predetermination Application filed by Evergy Kansas Central, Inc. (EKC), Evergy Kansas South, Inc. (EKS) and Evergy Metro, Inc. (EKM) (all together referred to as Evergy)?

A. In the testimony that follows, I will present and support Staff's positions regarding Evergy's requested predetermination of ratemaking principles and treatment to be applied to:

1. EKC's 50% ownership of the proposed Viola Generating Station (Viola), a 710 megawatt (MW) Combined Cycle Gas Turbine (CCGT) to be located in Sumner County, Kansas;
2. EKC's 50% ownership of the proposed McNew Generating Station (McNew), a 710 MW CCGT to be located in Reno County, Kansas; and
3. EKC's ownership of a proposed 159 MW_{AC} solar generation facility known as Kanas Sky Solar (Kansas Sky or Solar), located in Douglas County, Kansas.

My testimony will aid the Commission in its evaluation of Evergy's filing by applying the standards in K.S.A. 66-1239, including:

1. A determination of whether the resources identified above are consistent with Evergy's most recent preferred plan and resource acquisition strategy submitted to the Commission;

2. Whether Evergy issued a request for proposal from a wide audience of participants willing and able to meet the needs identified under its preferred plan; and

3. Whether the plan selected by Evergy is reasonable, reliable and efficient.

The testimony below reviews the reasonableness, reliability, and efficiency of the CCGTs and the Solar facilities separately. Additionally, I will address the reasonableness of Evergy's requested ratemaking treatment and definitive cost estimates for the Viola, McNew, and Kansas Sky facilities, as well as the levelized revenue requirement and construction accounting treatment requested for the Kansas Sky facility.

II. Executive Summary

Q. Please provide an executive summary of your testimony.

A. In the testimony that follows, I will present and support the following conclusions, in the order that each appears in my testimony:

- K.S.A. 66-1239 contemplates that the analysis of Evergy's investment plan will consider, in part, consistency with Evergy's most recent preferred plan and resource acquisition strategy.[1] Evergy's plan to acquire a 50% portion of the Viola plant, a 50% portion of the McNew plant, and 100% of the Kansas Sky solar facility, is consistent with Evergy's most recent preferred plan and resource acquisition

[1] *See* K.S.A. 66-1239(c)(2).

strategy, as contained within Evergy's 2024 IRP filing, and as updated through the modeling and analysis presented by Evergy witness Cody VandeVelde in this Docket.[2]

- K.S.A. 66-1239 contemplates that the analysis of Evergy's investment plan will consider, in part, if Evergy issued a request for proposal (RFP) from a wide audience of participants willing and able to meet the needs identified under its preferred plan.[3] Evergy has solicited several RFPs from a wide audience of participants willing and able to meet the needs identified under its preferred plan. Evergy has utilized a competitive bidding process to select the Owner's Engineer (OE), the Engineer Procure Construct (EPC) contractor, the Power Island Equipment (PIE) contractor and the Generator Step-Up (GSU) transformers for the CCGTs. Evergy also utilized a competitive process to select the EPC contractor and solar module supplier for the Solar project.
- K.S.A. 66-1239 contemplates that the analysis of Evergy's investment plan will consider, in part, if Evergy's investment plan is reasonable, reliable, and efficient.[4] Evergy's investment plan, consisting of the 50% ownership of each CCGT and the 100% ownership of the Solar facility, is reasonable, reliable and efficient, subject to the conditions and compliance filing recommendations discussed in detail later in this testimony. Accordingly, Staff recommends that the Commission find it is

[2] Evergy's 2024 IRP was filed in Docket No. 24-EKCE-387-CPL (24-387). https://estar.kcc.ks.gov/estar/portal/kscc/PSC/DocketDetails.aspx?DocketId=b9e04bef-9c67-4200-acb2-81585e41f52c
[3] *See* K.S.A. 66-1239(c)(3).
[4] *Id*.

prudent for Evergy to acquire these resources, up to the Definitive Cost Estimates (DCEs) Staff recommends for each asset, as discussed later in this testimony.

- The IRP is designed to consider a wide range of potential alternative scenarios and alternative resource portfolios, and the process is designed to select the least cost mix of resources amongst the backdrop of a highly uncertain future. The fact that the CCGTs and Solar facilities were selected as part of the preferred plan in Evergy's 2024 IRP is a strong indication that these resources are reasonable, reliable and efficient. This is bolstered by the fact that near-term CCGT resources were also supported by the 2023 IRP (1,042 MW in 2028 and 2029), and near-term solar resources have been supported in each IRP since 2021.[5]
- The decision to build the CCGT facilities is reasonable in part because they are both reliable and efficient. Additionally, Staff considers the following to be additional support for the reasonableness of the decision to build the CCGTs:
  - It is reasonable to plan for the eventual retirement of Evergy's coal fleet, even if the specific date that any individual coal unit will retire is uncertain at this time;
  - Evergy currently anticipates load growth of 2-3% annually through 2029 and has a robust economic development pipeline that would more than double its current peak demand if it all materialized. Evergy is not alone in this regard as SPP too is experiencing rapid load growth and declining

[5] *See generally* Docket No. 19-KCPE-096-CPL, which contains Evergy's IRP filings for 2021 through 2023. https://estar.kcc.ks.gov/estar/portal/kscc/PSC/DocketDetails.aspx?DocketId=6466c623-7063-4114-b608-feff73520a6d

reserve margins. An example of the rapid and unexpected nature of this load growth is that SPP's year 2 load forecast in the 2024 Integrated Transmission Plan (ITP) was higher than the year 10 load forecast presented in the 2023 ITP;

- It will allow Evergy the ability to reliably serve native load and respond to increased load growth in Evergy's service territory, with dispatchable, highly efficient generation;
- It positions Evergy well for a highly uncertain future, even if that future is dominated by intermittent, weather dependent sources of energy such as wind and solar, or more significant restrictions on the production of carbon dioxide as a byproduct of electricity generation;
- It helps Evergy respond to increasingly tighter Resource Adequacy (RA) standards being enacted by the SPP, including recent increases in the Planning Reserve Margin (PRM), the implementation of Performance Based Accreditation (PBA) and Fuel Assurance (FA) for conventional generators, and the implementation of Effective Load Carrying Capability (ELCC) for renewable generators;
- It allows EKC to further increase the diversity of its electric generation fuel sources, moving natural gas from 21.4% of installed capacity to 27.97% of installed capacity, compared to the SPP region which currently has approximately 31% natural gas capacity. This would also move EKC's coal

capacity proportion from 40.8% down to 37.4%, compared to the SPP region as a whole which has approximately 21% coal capacity;[6] and

- It is responsive to the Energy Policy signals provided by the Kansas Legislature and the Governor, as expressed through the passage of House Bill 2527, in which new natural gas-fired generation was the only generation type to be allowed to be recovered from customers via a new surcharge on customer bills.

- Staff contends the decision to build the CCGTs is reliable because:
    - The CCGTs will add highly flexible, dispatchable generation to the system, which offers critical reliability services for customers, like the ability to ramp up and down quickly when needed. Regional reliability organizations like the Midwest Reliability Organization (MRO) and SPP have explicitly recognized the critical role that natural gas fired generation serves to maintain the reliability of today's power grid, as discussed in more detail in the body of my testimony below. The National Electric Reliability Corporation (NERC) has also recognized the critical importance of natural gas fired generation for winter reliability, most recently in its 2024/2025 Winter Reliability Assessment.
    - These CCGTs are being built to withstand winter temperatures as low as minus 15 Fahrenheit[7] and they will be served by firm natural gas

[6] All of these capacity calculations are as a percentage of nameplate (maximum generating capability of the resources, prior to any decrement for accreditation policies like PBA or ELCC).
[7] *See* Evergy Response to Staff Data Request No. 15. All Public Data Requests Referenced herein are attached to this testimony as Staff Exhibit JTG-13.

transportation contracts. While Evergy does not have a signed contract for firm gas transportation at this point, it is in involved in negotiations with gas pipelines and does have a plan to achieve firm transportation. Staff recommends that Evergy be required to submit a compliance filing to the Commission once firm natural gas transportation arrangements have been finalized.

- Recent weather events have shown that there have been significant improvements since Winter Storm Uri in the ability of the natural gas and electric industries to maintain reliability during extreme winter weather events.
- The CCGTs are expected to have very low forced outage rates. In a December 2024 SPP SAWG meeting, SPP reported that CCGTs within SPP's territory have better Demand Equivalent Forced Outage Rate (EFORd) and Equivalent Forced Outage Factor (EFOF) reliability values, both in summer and winter, than Combustion Turbines (CTs), or Reciprocating Internal Combustion Engines (RCIPs), even when these other generation types have on-site liquid fuel storage.[8]
- Section 18 of Evergy's 2024 IRP analysis evaluated the reliability of the preferred resource plan using the Strategic Energy and Risk Valuation Model (SERVM) software. These results showed that Evergy's preferred resource plan would exceed the industry standard loss of load expectation

[8] *See* Exhibit JTG-1, December 2024 SAWG Presentation of On-Site Fuel Survey Results.

(LOLE) metric of .1 (one day in ten years or .1 day per year). These results are far superior to the scenario in which the capacity expansion model was only allowed to select renewables and energy storage resources, with that plan producing LOLE results 3 times higher than the industry standard.[9]

- Staff contends the decision to build the CCGTs is efficient because:
  - These CCGTs are highly efficient, in terms of the ability to generate one megawatt hour (MWh) of electricity per million British Thermal Units (MMBtus). These CCGTs will be able to generate one MWh of electricity with just **[redacted]** MMBtus[10] of natural gas, an efficiency gain of **[redacted]** compared to the average gas unit in Evergy's fleet, **[redacted]** from the least efficient gas unit in the fleet, and **[redacted]** more efficient that the most efficient unit in the fleet.[11] This also means that during periods of relative scarcity of natural gas, as was experienced during Winter Storm Uri, these CCGTs will be able to produce electricity by burning approximately ***half*** of the fuel required from the least efficient unit in Evergy's fleet. That level of efficiency will also improve the reliability of the entire interconnected gas and electric system in Kansas.
  - As discussed earlier, the proposed CCGTs are approximately 40% more efficient than the average natural gas unit in Evergy's fleet. The low heat rate of these units acts to insulate customers from price spikes in natural

[9] *See* SERVM Reliability analysis, beginning at page 136 of Evergy's 2024 IRP.
[10] Equivalently, **[redacted]** British thermal units (BTUs) will be required to produce one kWh of electricity.
[11] *See* Evergy Confidential Response to CURB Data Request No. 17 in Docket No. 24-EKCE-387-CPL. All Confidential Data Responses referenced herein are attached hereto as Staff Exhibit JTG-14.

gas, because the units use less of the commodity to produce electricity. While Evergy has yet to develop a natural gas procurement and hedging plan that will allow natural gas for these plants to be procured through longer term, more stable prices, Evergy is working on such a plan and Staff recommends that the Commission require the plan to be filed in a compliance filing as a condition of approval for the CCGTs.

- The CCGTs were selected as part of the updated 2024 IRP analysis that Evergy conducted in support of this Application. The capacity expansion modeling used by Evergy selects the least cost portfolio of resources, given a certain set of constraints, assumptions, and scenarios. When Evergy conducted its capacity expansion modeling using the updated costs of the CCGTs, the model still selected one full 710 MW combined cycle facility by 2030. This is evidence that the CCGTs that are the subject of this proceeding are efficient.
- The competitive process that Evergy has utilized to construct and select these projects will ensure that they are efficiently priced. Additionally, Evergy plans to economically commit the CCGTs in the SPP IM, ensuring efficiency of dispatch.[12]
- As part of Staff's evaluation of the CCGTs in this proceeding, Staff contracted with S&P Global Market Intelligence to gain access to the Power

[12] *See* Evergy Response to Staff Data Request No. 57, contained in Exhibit JTG-13.

Evaluator software platform.[13] Using Power Evaluator, Staff simulated the addition of the Viola CCGT at the exact physical location where Evergy intends to construct this resource. The result was an anticipated 77.19% capacity factor in year 1, evaluated through economic dispatch simulation on an hourly basis. Power Evaluator also calculated a Levelized Cost of Energy (LCOE) for the Viola CCGT, which was estimated at $68/MWh. Staff also used Power Evaluator to evaluate the addition of the McNew facility. This facility was estimated by the software to have an 72.61% capacity factor in the first year, with a LCOE estimated at $74/MWh.

- The estimated capacity factors indicate that the CCGTs will be economic units that will be frequently dispatched into the SPP Integrated Marketplace (IM). Additionally, the estimated LCOE figures calculated by the Power Evaluator software compare favorably to the average LCOE of $76/MWh reported for a new CCGT by the Lazard 2024 LCOE report, which provided a range of LCOEs for new CCGTs between $45 to $108/MWh.[14]
- The CCGTs will be very efficient from a carbon dioxide emissions perspective. In response to Staff Data Request No. 43, Evergy reports that the CCGTs will be capable of operating with a CO2 emissions level of 800 pounds of CO2 per MWh.[15] That level of carbon emissions reflects a 61%

[13] This software allows the simulation of the interconnection of a new generating plant at a specific geographic location, providing nodal-level economic and reliability analysis of a prospective power plant.
[14] Attached as Staff Exhibit JTG-2.
[15] *See* Evergy Response to Staff Data Request No. 43, contained in Exhibit JTG-13.

reduction from the average coal-fired generation unit in EKC's fleet today, and a 53% reduction from the average natural gas CT in EKC's fleet today.

- The decision to build the Kansas Sky solar facility is reasonable in part because it is both reliable and efficient. Additionally, Staff considers the following as additional support for the reasonableness of the decision to build the Solar facility:
    - Evergy's IRP has supported the addition of near-term solar since 2021. Evergy's 2021 IRP called for 350 MW of solar by 2023. The 2022 IRP called for 190 MW of solar by 2024, and the 2023 IRP called for 150 MW of solar by 2027. Evergy's 2024 IRP supported the 2027 solar build in every scenario studied, even in scenario AFAD, which was specifically optimized for a future with little carbon constraints, and which did not allow any coal retirements other than the conversion of Lawrence 5 to natural gas, and the retirement of Lawrence 4 in 2028. When Evergy created a scenario to force the model not to choose 150 MW of solar in 2027, the result was an increase in costs of $59 million in Net Present Value Revenue Requirements (NPVRR).
    - The addition of this solar farm, while small compared to the overall generation portfolio of EKC, will improve the diversification of Evergy's generation mix, and provide a hedge against higher natural gas and wholesale market prices. Because the Solar resource is located close to Evergy's load, the SPP IM revenue profile of the Solar facility is expected to be better correlated to Evergy's cost to serve load in the SPP IM than the wind generation sites in Evergy's footprint.

- Staff contends the decision to build the Solar facility is reliable because:
    - There is very little utility scale solar in SPP today, just 986 MW as of January 1, 2025. Accordingly, the reliability value of adding additional solar into SPP right now is very high, and it is anticipated that these assets will receive high summer ELCC accreditation percentages (65-70%) when they are installed.
    - While adding solar to Evergy's generation profile does not support summer reliability in the same fashion that dispatchable generation does, it does have reliability benefits and will help improve reliability for EKC's customers once it enters service. Utility scale solar is naturally summer peak correlated, and it tends to have an offsetting generation profile to that of wind generation assets. In other words, many times when wind is dying down in the morning hours, solar resources are ramping up. Accordingly, the addition of solar to the grid can cut down on the ramping requirements of conventional generators on the system, when wind suddenly dries up on the hottest days of the summer. You can see this relationship play out nearly every day in ERCOT, as ERCOT's solar portfolio has grown to over 20GW of installed capacity in just the last few short years.[16] This solar is widely credited with helping ERCOT meet extreme peak demands that occurred on its system during the summer of 2024.[17]

[16] See Combined Wind and Solar graph at www.ercot.com

[17] *See* NREL How the U.S. Power Grid Kept the Lights on in Summer 2024, attached as Exhibit JTG-3.

    - While solar generation does not contribute to the winter capacity needs of EKC or SPP in the same fashion as a dispatchable generator can, it does provide reliability benefits during the winter, especially coming from a place of having almost no solar on the system. This is especially true on extremely cold mornings, in which the absence of cloud cover allows the surface temperatures to cool significantly.
    - The winter reliability value of adding solar to the SPP system was discussed extensively in SPP working groups[18], last summer when the SPP set its first financially binding Winter PRM. The results plainly demonstrate the reliability value of utility scale solar to help EKC serve the reliability needs of its customers in the Winter.
- Staff contends the decision to build the Solar facility is efficient because:
    - The LCOE of the Solar facility, calculated by Evergy to be **[redacted]**, is lower than all PPA offers received by Evergy in its 2023 all source RFP, except for one project that was **[redacted], [redacted]**.[19]
    - When adjusted by Staff to remove future "maintenance" capital expenditures anticipated by Evergy in years 12-16; to update the capacity factor to **[redacted]**[20] to reflect the most recent estimate; and to reflect the reduction in anticipated construction costs to account for the updated lower

[18] Including (but not limited to) Supply Adequacy Working Group (SAWG), the Cost Allocation Working Group (CAWG), the Resource and Energy Adequacy Leadership Team (REAL), the Regional State Committee (RSC) and the SPP Board of Directors.
[19] *See* Evergy Confidential Response to Staff Data Request No. 35, contained in Exhibit JTG-14.
[20] *See* Evergy Confidential Response to KIC Data Request No. 4.1, contained in Exhibit JTG-14.

cost of purchased **[redacted]**[21], Staff's calculated LCOE for the Solar project is **[redacted]**.[22]

- The anticipated all-in capital cost of the Solar facility at **[redacted]** (accounting for Staff's adjustment), compares favorably with other recently announced utility scale solar projects, including those described on page 20 of Evergy witness John Carlson's Direct Testimony, as well as another recently announced solar project in Missouri, with an anticipated capital cost of $950 million for 500 MW, or $1,900/kW.[23]

- While the decision to acquire Kansas Sky Solar is reasonable, reliable, and efficient based upon Staff's analysis, there are also risks that should continue to be closely monitored and evaluated, specifically:
  - There is currently a significant amount of uncertainty as to the fate of the renewable energy tax credits that were authorized by the Inflation Reduction Act of 2022 (IRA).[24] As demonstrated by confidential Exhibit JC-4, attached to Evergy witness John Carlson's Direct Testimony, the assumed production tax credits (PTC) for this Solar facility significantly impact the LCOE of the facility. Using this LCOE model, when the PTC was made unavailable, Staff calculated a **[redacted]** increase in the LCOE from the Solar facility, from **[redacted]** to **[redacted]**. Staff

[21] *See* Evergy Confidential Response to Staff Data Request No. 20 (response attached in Exhibit JTG-14, attachments to the response available upon request).
[22] *See* Confidential Staff Exhibit JTG-4 for support for this LCOE calculation.
[23] *See* https://fox2now.com/news/missouri/ameren-missouri-brings-3-solar-facilities-online/
[24] *See* Republicans to grapple with clean energy tax credit repeal amid budget talks, February 26, 2025, attached as Staff Exhibit JTG-5.

recommends that the Commission approve the decision to build the Solar facility with the condition that if the PTC provisions of the IRA are repealed prior to the beginning of construction on the Solar facility, that Evergy be required to make a compliance filing to the Commission justifying the continued prudence and economic efficiency of the decision to construct the Solar facility.

- The Solar project is currently involved in litigation pertaining to the issuance of a Conditional Use Permit (CUP) by Douglas County, Kansas, as discussed on page 6 of the Supplemental Direct Testimony of Jason Humphrey. Staff is not recommending a condition of approval pertaining to this outstanding CUP issue, because Evergy's Purchase and Sale agreement with the developer of the Solar facility contains an explicit condition precedent that requires this issue to be resolved before Evergy will close on the project.

- Staff recommends the Commission approve the following regarding the requested ratemaking treatment and Definitive Cost Estimates (DCE) for the CCGTs and the Kansas Sky Solar facility:
  - Staff recommends that the Commission approve as reasonable Evergy's requested DCE for the Viola CCGT of **[redacted]** (excluding AFUDC[25]), (**[redacted]** for a 50% share), as depicted on Evergy witness Kyle Olson's Confidential Exhibit JKO-10.

[25] Allowance for Funds Used During Construction is a regulatory accounting methodology that allows regulated utilities to capitalize financing costs associated with the construction of utility assets as part of the

- For the McNew CCGT, Staff recommends a revised DCE of **[redacted]** (excluding AFUDC), (**[redacted]** for a 50% share). This reflects a reduction of **[redacted]** from Evergy's requested DCE, as listed in Confidential Exhibit JKO-11. Staff contends that this revised DCE better reflects the projected costs of the PIE Equipment for the McNew CCGT. As discussed in confidential response to Staff Data Request No. 51, Evergy rounded down the **[redacted]** estimate for the Viola CCGT to **[redacted]** but rounded up an estimated **[redacted]** amount for the McNew CCGT to **[redacted]**. Staff contends that similar to the **[redacted]** estimate, the PIE estimate for the McNew CCGT should be rounded down to **[redacted]**.[26]
- Consistent with the Commission's previous decision in the 11-KCPE-581-PRE Docket (11-581 Docket), Staff recommends that Evergy bear the burden of proof to show that any amount it incurs in excess of these DCEs is "prudently incurred and is reasonable to recover from ratepayers."[27]
- Staff recommends that the Commission approve a revised DCE for the Kansas Sky Solar project of **[redacted]** (excluding AFUDC), a reduction of **[redacted]** from Evergy's requested DCE of **[redacted].** This adjustment reflects the lower agreed upon purchase price

total asset cost. AFUDC ceases to accumulate when a utility asset is placed in utility rate base, or when it is placed in service.

[26] *See* Evergy Confidential Response to Staff Data Request No. 51, contained in Exhibit JTG-14.

[27] *See* Order Granting KCP&L Petition for Predetermination of Ratemaking Principles and Treatment, ¶¶ 73, 75, Docket 11-581 (Aug. 19, 2011).

of the **[redacted]**, as described in Exhibit JOH-2 attached to the Supplemental Direct Testimony of Jason Humphrey.

- Staff recommends that the Commission approve the ratemaking treatment described in the Direct Testimony of Darrin Ives at page 21 pertaining to construction cost accounting and the use of deferred accounting to capture the revenue requirement impacts of the Solar facility prior to the facility being reflected in rates.
- Staff recommends that the Commission require Evergy to update the Kansas Sky Solar levelized revenue requirement in the first rate case after the facility goes into service, to account for actual construction costs once they are known, subject to the revised DCE identified above, or a prudency evaluation for costs incurred in excess of the DCE. Staff's current estimate of the levelized revenue requirement for the Kansas Sky facility is **[redacted]** per year, which is a reduction from the **[redacted]** calculated in Evergy's filing.[28] The difference in these levelized cost estimates pertains to Staff's recommendation to remove future "maintenance" capital expenditures estimated by Evergy to occur in years 12-16, an update to the anticipated capacity factor of the Solar unit, and an update to reflect the cost of the solar panels secured by Evergy.[29]

[28] *See* Staff Exhibit JTG-4 for Staff's calculation of the Levelized Revenue Requirement of Kansas Sky.
[29] As discussed below, Evergy should be required to request recovery of these maintenance capital expenditures in a frequent rate case, after the actual capital is expended.

III. Consistency of Evergy's Application with its 2024 IRP

A. Viola and McNew CCGTs

Q. K.S.A. 66-1239 contemplates that the analysis of Evergy's investment plan will consider, in part, consistency with Evergy's most recent preferred plan and resource acquisition strategy. Is EKC's decision to build and own 50% of the Viola and 50% of the McNew CCGTs consistent with the Preferred Resource Plan selected through the 2024 IRP filing?

A. Yes. Evergy filed its 2024 IRP filing on May 17, 2024, in Docket No. 24-EKCE-387-CPL.[30] This filing considered a wide range of potential alternative scenarios and alternative resource portfolios, ultimately selecting the mix of resources that Evergy determined would perform very well against the backdrop of a highly uncertain future. In that filing, EKC's preferred portfolio consisted of the addition of 325 MW of CCGT in 2029, 325 MW of CCGT in 2030, and 650 MW of CCGT in 2031.[31] The 50% share (355 MW) of the Viola CCGT, corresponds to the 325 MW CCGT in 2029. The 50% share of the McNew CCGT in 2030 corresponds to the 325 MW CCGT in 2030.

[30] *See* 24-387 Docket filings here: https://estar.kcc.ks.gov/estar/portal/kscc/page/docket-docs/PSC/DocketDetails.aspx?DocketId=b9e04bef-9c67-4200-acb2-81585e41f52c

[31] It is unclear at this time whether Evergy still intends to request approval to build an additional CCGT in 2031, given the updated capacity expansion modeling results described in Evergy witness Cody VandeVelde's Direct and Supplemental Testimonies.

Q. Why did Evergy perform updated capacity expansion modeling and what was the result?

A. As described in pages 23-25 of VandeVelde's Direct Testimony, the original cost estimate of the CCGTs evaluated in Evergy's 2024 IRP was $1,271/kW, which was stressed by +/- 25%, up to $1,560/kW as explained on page 16 of Evergy witness Jason Humphrey's Direct Testimony. At the time Evergy filed Direct testimony, the estimated cost of construction of the CCGTs had increased approximately **[redacted]** since the 2024 IRP, so Evergy performed an updated capacity expansion modeling analysis to verify whether the higher cost CCGTs would still be selected as part of the preferred resource plan. This analysis was also updated to reflect the Definitive Cost Estimates, averaging **[redacted]** as described in pages 6 and 7 in VandeVelde's Supplement Direct Testimony,

The result of these updated capacity expansion modeling runs confirmed the selection of one full CCGT prior to 2030. However, the 2031 CCGT was replaced by battery storage and a combustion turbine (CT). Accordingly, it is unclear at this point whether Evergy will eventually request predetermination of a 2031 CCGT build.

B. Kansas Sky Solar

Q. Is EKC's decision to build the Kansas Sky Solar facility consistent with the Preferred Resource Plan selected through the 2024 IRP filing?

A. Yes. Evergy's 2024 IRP called for the addition of 150MW of Solar in 2027. The generic solar resource modeled by Evergy was approximately 30% higher than the current estimated cost of the Kansas Sky Solar facility.[32] As a result, as described in Cody VandeVelde's Direct Testimony at page 23, all other things being equal, the NPVRR of adding the Solar facility is estimated to be $43 million *lower* than modeled in the 2024 IRP. Given these cost savings, unsurprisingly, this resource was also chosen in the updated capacity expansion modeling performed by Evergy in this Docket.

IV. Issuance of an RFP from a Wide Audience of Participants

A. Viola and McNew CCGTs

Q. K.S.A. 66-1239 contemplates that the analysis of Evergy's investment plan will consider, in part, if Evergy issued a request for proposal (RFP) from a wide audience of participants willing and able to meet the needs identified under its preferred plan. Did Evergy issue an RFP from a wide audience of participants willing and able to meet the needs of constructing the CCGTs?

A. Yes. Mr. Humphrey's Direct Testimony describes how Evergy issued an all-source RFP in 2023, however, there were no thermal resources submitted in response to that RFP. However, as discussed in the Direct Testimony of Evergy witness Kyle Olson, Evergy did conduct competitive bidding processes to select the contractors that would build the CCGTs, as well as the suppliers of all major equipment for the CCGTs. The following response to CURB Data Request No. 18, summarizes this process:

> Evergy has run a competitive process at every step of this project. The selection of advanced class machines was made on the anticipation of the lowest cost per kilowatt resource with the highest

[32] *See* Direct Testimony of Darrin Ives, page 22, line 11.

> efficiency and the most flexibility for customers. The owner's engineer was selected through a competitive RFP, the gas turbine provider was selected from a competitive RFP to all major gas turbine suppliers, the generator-step-up transformers were selected through a competitive RFP and the EPC is being selected through a competitive RFP. Every phase of the project has been advanced through a competitive process and is striving for the best balance of cost, reliability, execution, long-term flexibility, and ability to meet market mission. The supply and demand forces affecting the market for firm-dispatchable power have caused prices to increase but, as evidenced by the recent pricing from Basin Electric and similar pricing from other referenced utilities, Evergy's prices are in line with or slightly better than the broader market today.

B. Kansas Sky Solar

Q. Did Evergy issue an RFP from a wide audience of participants willing and able to meet the needs of constructing the Kansas Sky Solar facility?

A. The Solar project was not selected through an RFP process, because Kansas Sky was nearing completion of negotiations with Evergy when the 2023 RFP was issued.[33] However, the Solar project did compare favorably to the results of the 2023 RFP, including PPA offers,[34] and the major components of construction were procured through competitive processes and RFPs, as described in Evergy witness John Carlson's Direct Testimony at pages 8 and 19.

[33] *See* Evergy Confidential Response to CURB Data Request No. 13, contained in Exhibit JTG-14.
[34] *See* Evergy Confidential Response to Staff Data Request No. 35, contained in Exhibit JTG-14.

V. Reasonableness of the Decision to Build CCGTs

A. Overview

Q. K.S.A. 66-1239 contemplates that the analysis of Evergy's investment plan will consider, in part, if Evergy's investment plan is reasonable. What factors do you believe the Commission should consider when determining whether Evergy's decision to build the CCGTs is reasonable?

A. In the testimony that follows I will address several specific factors that I believe the Commission should consider when making the determination of whether it is reasonable for Evergy to acquire a 50% interest in the Viola and McNew CCGTs. At the outset though, Staff considers the decision to acquire these CCGTs to be reasonable because they are both reliable and efficient. Additionally, the fact that the CCGTs have been supported by the 2023 IRP and 2024 IRP, as well as the updated capacity expansion modeling performed by Evergy in this Docket, is highly supportive of the reasonableness of this decision. The IRP is designed to consider a wide range of potential alternative scenarios and alternative resource portfolios, and the process is designed to select the least cost mix of resources amongst the backdrop of a highly uncertain future.

1. Connection between Anticipated Coal Retirements and CCGTs

Q. One of the drivers of the need to build the CCGTs in Evergy's preferred plan from the 2024 IRP is to replace the capacity from the retirement of Jeffrey Energy Center (JEC) units 2 and 3 in 2032. Why is it reasonable and prudent to plan for the retirement of the JEC coal units, even if the ultimate date of that retirement might be pushed beyond 2032?

A. Staff considers it reasonable and prudent to plan for the eventual retirement of Evergy's coal fleet because the future of these units is highly uncertain. While these units might not retire at the precise time Evergy's 2024 IRP is currently planning, at some point, these units will retire. The final driver might be because of their advanced age or because it is more economic to retire them, or because of environmental policies that force them to undergo costly retrofits or retire. Because we do not have perfect foresight, Staff contends that it is prudent to maintain a diversified generation mix, while also developing the ability to responsibly and reliably react to what the future brings for these units.

The oldest of the JEC units will be 51 years old by the time that the first CCGT unit comes online.[35] As an example of how the industry at large is planning for the eventual retirement of coal generation, SPP's 2023 ITP planning model in Future 1, which is the business-as-usual scenario, assumes that coal units in the region will retire at age 56 by 2042.[36] SPP's Future 2 planning model (an emerging

[35] The Jeffrey units were commissioned in 1978, 1980, and 1983.
[36] For a discussion of the different SPP Futures in the 2023 IRP, see Section 3.1.1 of Volume 5 of Evergy's 2024 IRP.

technologies scenario which incorporates assumptions about the growth of electric vehicles, distributed generation, and a higher penetration of renewables) assumes that coal units in the region will retire at age 52.

The reality is that today, we simply do not know the exact age that these units will retire. Load growth in Evergy's service territory may extend their lives. Environmental policy or technological innovation might shorten their lives. The CCGTs that are the subject of this proceeding will enable Evergy to produce dispatchable energy and maintain reliability for customers when these coal units do eventually retire. Staff supports Evergy's advanced planning for this eventuality, and we consider it a better option than the alternative of being forced to respond in a hasty and likely suboptimal fashion in response to a sudden coal retirement at some future date.

Q. Can you explain how Evergy's IRP accounts for this kind of uncertainty?

A. Evergy's IRP is designed to test different alternative resource portfolios against 27 different end points (scenarios), each of which involves a different view of what the future brings for several different critical uncertain factors, including natural gas prices, CO_2 emissions policy, and construction costs. An expected value is then calculated from the NPVRR of each of the resource portfolios in each of these 27 different combinations of critical uncertain factors. The preferred resource plan is generally expected to score well in terms of the expected value NPVRR, when compared to other resource plans.

An example of the value of planning for an uncertain future can be viewed by examining the expected value NPVRR of two alternative resource portfolios studied in the 2024 IRP when compared to the preferred plan. Both of these alternative portfolios were specifically designed to outperform all other portfolios under a specific view of the future. One was a portfolio entitled AFAD, which was optimized (using capacity expansion modeling software) for a future that is characterized by low natural gas prices and low restrictions on CO2 emissions. The other portfolio, AAAC was optimized for a future consisting of high natural gas prices and high CO2 emissions restrictions. The result of the NPVRR of each portfolio, compared to the preferred resource plan of Evergy, is shown below.

Kansas Central GHG and No Environmental Rules

Rank	Plan	NPVRR	Difference	Description
1	AAAA	34,092		Base planning assumptions
2	AAAC	34,860	768	High/High GHG rules
3	AFAD	36,490	2,398	Low/Low, No retirements

This example demonstrates the potential for increased cost of developing a resource portfolio around a particularly narrow set of assumptions about what we believe (or hope) the future may bring. If Evergy plans for a certain narrow view of what it expects the future may bring, and the actual future ends up being dramatically different, than the selected resource plan will end up being much more costly for customers.

Q. Are there specific events involving Evergy's coal facilities over the last several years that reinforce the prudence of planning for an uncertain future?

A. Two specific events resonate with me. The first is Evergy's request to purchase the last 8% of JEC (174 MW) resulting from an expired sale leaseback transaction, filed on March 4, 2019, in Docket No. 19-WSEE-355-TAR (19-355 Docket). In that Docket, Evergy requested Commission approval to acquire 174 MW of JEC from the lessor in the sale leaseback arrangement. While Staff supported this decision based on our financial modeling and analysis, it was a controversial filing, that was opposed by all other intervenors in the case. Ultimately the Commission denied Evergy's request, finding "Westar's decision to enter into the new lease and purchase agreement for the 8% interest in JEC was not a prudent decision for its retail customers."[37]

The prevailing industry attitude about coal facilities around the time of the 19-355 Docket was that these facilities were quickly becoming obsolete assets that could not keep up with the energy transition occurring within the marketplace. Many stakeholders at the time viewed these assets as inflexible generation sources that were rapidly losing ground to more economic and cleaner sources of generation. At the time, peak load growth had been flat for decades, SPP had excess capacity, and many viewed Evergy's coal fleet as a liability for ratepayers. Importantly, this Docket occurred before the reliability and affordability shock of Winter Storm Uri, and the natural gas price shocks that occurred during the summer of 2022.

Just four years later, Evergy again requested to include the 8% of JEC in rate base in the Docket No. 23-EKCE-775-RTS (23-775 Docket). This time, in an environment of significant economic development gains, an unexpected natural gas price shock in the summer of 2022, an increasing focus on reliability, dispatchability, and resource adequacy concerns regionally, it was not a

[37] Order on Westar's Application to Recover Certain Costs Through its R.E.C.A. Related to the 8% Portion of Jeffrey Energy Center, p. 16, 19-355 Docket (Sep. 12, 2019).

controversial decision to add this 8% of JEC to rate base. The same parties that opposed this request just four years earlier were part of the unanimous settlement agreement and support for this decision.

I use this example not to be critical of any party, and certainly not to be critical of the Commission's decision in the 19-355 Docket. I highlight this example as a reminder of the inherent uncertainty involved in resource planning decisions involving generation assets that may well last 40 years or more, and how quickly the environment of the industry in which these decisions are made can change.

Q. What is the second example that you alluded to earlier?

A. The second example is the catastrophic fire that JEC unit 3 suffered on Saturday October 1, 2022. This fire occurred from a severe mechanical failure in the steam turbine, which led to an extreme vibration issue, hydrogen fires in the electrical generator, and a complete loss of the high-pressure rotor, the intermediate-pressure rotor and significant repairs on the low-pressure turbine and electrical generator. This event caused JEC 3 to be out of service for 15 months. The unit was unavailable to meet winter peak requirements for two years, and summer peak requirements for one year. The loss of JEC 3 also caused Evergy to have to buy paper capacity[38] just to meet its Summer Capacity reserve requirements for 2023.[39]

[38] Paper capacity in this context is a bilateral transaction in which a utility, in this case a load serving entity in SPP, can purchase deliverable capacity to meet its SPP RA requirements.
[39] *See* Direct Testimony of Linda J. Nunn on Behalf of Evergy Metro, Inc., Evergy Kansas Central, Inc. and Evergy Kansas South, Inc., p. 27, 23-775 Docket (Apr. 25, 2023).

This event is a reminder that Evergy's coal units are aging, and sometimes mechanical failures happen that cannot be anticipated ahead of time. This also reinforces the concept that a diversified generation mix, relying on several fuel types and generation technologies, is reasonable and prudent. It also reinforces the need for Evergy to modernize its dispatchable generation fleet to lessen the likelihood of such sudden severe mechanical failures.

Q. If the Commission approves the decision to build the Viola and McNew CCGTs, is it a foregone conclusion that Evergy will retire one of its coal units, on any specific timeline?

A. No. Evergy has not formally requested the Commission approve the retirement of any specific coal unit at this time. While Evergy's IRP has called for the retirement of its coal units for several years now, Evergy has also demonstrated a willingness to delay the retirement of its coal units when facts and circumstances support that decision. Evergy has delayed the retirement of Lawrence 4 several times now and made the decision to convert Lawrence 5 to natural gas operations instead of retiring this facility. Additionally, Evergy has committed to evaluate the conversion of Lawrence 4 to natural gas, instead of a permanent retirement, in the 2025 IRP.[40] Also, see the response to KIC Data Request Nos. 2-2 and 4-9 for Evergy's take on the flexibility of its coal retirement plans.[41]

[40] *See* Evergy Confidential Response to Staff Data Request No. 1 in the 24-387 Docket, contained in Exhibit JTG-14.

[41] *See* Evergy Response to KIC Data Request Nos. 2-2- and 4-9, contained in Exhibit JTG-13.

2. Load Growth in Evergy's Territory and SPP Generally

Q. Is Evergy currently experiencing load growth in its service territory that contributes to the reasonableness of the decision to build the CCGTs?

A. Yes. During Evergy's 4th quarter earnings call on February 27, 2025, Evergy reported that it currently anticipates load growth of 2-3% annually from 2024 through 2029 in its service territories. Evergy's current large customer pipeline contains 11.2 GWs of potential load growth. That level of demand growth, if it came to fruition, would more than double Evergy's current peak demand of 10.6 GWs.[42]

Q. Is the SPP region experiencing rapid load growth that contributes to the reasonableness of the decision to build the CCGTs?

A. Yes. SPP is experiencing rapid load growth. At the October 29, 2024, SPP Board of Directors meeting, SPP approved the 2024 Integrated Transmission Plan (ITP). The year 2 load forecast that was included in the 2024 ITP was higher than the year 10 load forecast presented in the 2023 ITP. This was true for both Summer and Winter load forecasts. SPP's 2024 ITP year 10 load forecasts called for demand that was 9.7% higher in summer, and 12.9% higher in winter.[43] Evergy and SPP are not alone in forecasting significant new load growth over the next several years. A recent Grid Strategies report, updated in February 2025 anticipates 116 GW of

---

[42] Evergy's 4th quarter earnings presentation available here: https://investors.evergy.com/static-files/98c659f7-48f6-41a5-89b9-2106cf6c2550

[43] *See* ITP Assessment Report, pg. 22, available at www.spp.org.

load growth in the United States over the next five years. This forecast is up from just 23 GW of load growth projected when this report was compiled in 2022.[44]

Q. Why do these load forecasts support the reasonableness of Evergy's decision to build the CCGTs?

A. These load forecasts reinforce the need for Evergy to be able to serve its load, and potentially significant amounts of new load, with dispatchable, highly efficient generation. If Evergy is not able to serve new customers that want to connect in its service territory, then those customers will connect somewhere else in SPP, and Kansas will miss out on these economic development opportunities. Additionally, the SPP region is currently facing an environment of declining capacity reserve margins, as depicted by the following graphic, which was included in SPP's Summer 2024 Resource Adequacy Report:[45]

When capacity reserve margins are declining in this fashion, the expectation is that paper capacity will become less and less available, and more and more expensive. Additionally, wholesale power market prices may very well be higher and more

[44] See Grid Strategies updated load forecast presentation, attached as Exhibit JTG-6
[45] https://www.spp.org/documents/71804/2024%20spp%20june%20resource%20adequacy%20report.pdf

volatile, as higher priced resources are on the margin more frequently. The load growth trends we are seeing in the industry will only exacerbate these symptoms associated with declining reserve margins.

3. The CCGTs in a Carbon Constrained Future

Q. How would the CCGTs fare if the future was dominated by renewable energy sources, and there were significant legal restrictions for the emissions of CO2 when generating electricity?

A. Staff contends that the CCGTs are a good choice for Evergy and its customers even if the future is dominated by renewable energy sources and significant restrictions on the output of CO2 for electricity production. The support for this view is the efficiency of the units from a CO2 emissions perspective and the fact that these units will be highly flexible resources that will be able to respond well if the future of energy production is one that is dominated by renewable energy sources.

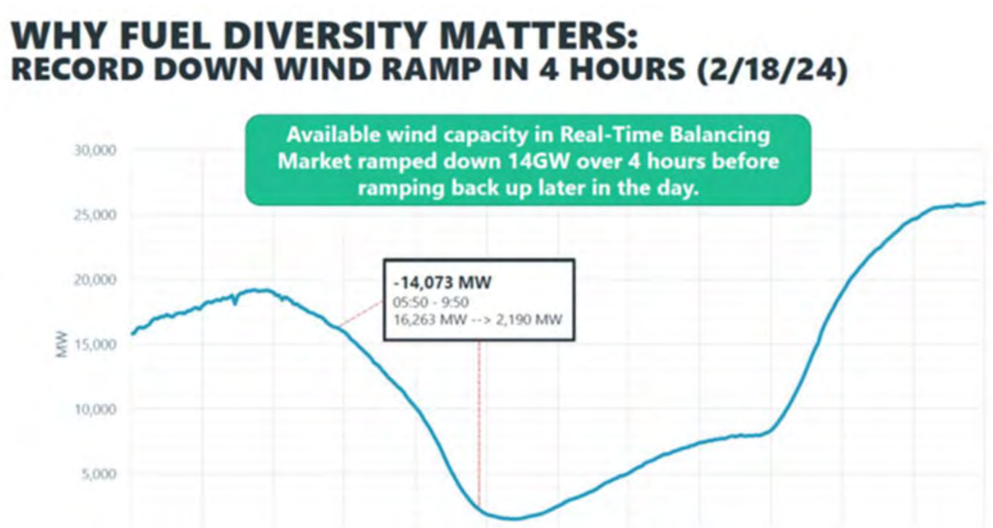
Q. Please discuss further the CO2 emissions efficiency of these units?

A. The CCGTs will be exceptionally efficient from a CO2 emissions perspective. In Staff Data Request No. 43, Staff requested the existing CO2 emissions rates, in pounds of CO2 per MWh, of each of EKC's existing coal and natural gas-fired generation units. The response indicates that the CCGTs will be capable of emitting just 800 pounds of CO2 per MWh, which is 61% less than the average coal unit in EKC's fleet, and 53% less than the average gas unit in the fleet.[46]

[46] *See* Evergy Response to Staff Data Request No. 43, contained in Exhibit JTG-13.

Q. Why do you contend that the CCGTs are a good choice, even in if the future is dominated by renewable energy sources?

A. In a future in which the predominant source of energy production is renewable energy, the CCGTs will be required to start up quickly, and ramp up and down as intermittent and weather dependent resources ebb and flow with weather patterns. An example of how this occurs with the level of wind in the SPP system today can be seen in the graphic below[47]:



It will also be important for dispatchable generation sources to operate at a low minimum output level when renewable energy is pushing down wholesale power prices.

[47] SPP Mike Ross, Presentation to the Kansas Senate Utilities Committee, February 6, 2025.

Q. What evidence exists to support the flexibility of the CCGTs to start-up quickly, ramp up quickly, and operate at a low minimum output?

A. In response to Staff Data Request No. 6, Evergy provided the minimum startup time, minimum load while running, and ramp rate in MWs per minute of the CCGTs. Evergy also provided each of these characteristics for its existing Coal and Gas fleet in response to Staff Data Request No. 44. The CCGTs will be significantly more flexible than EKC's existing coal and gas fleet in terms of minimum startup time, minimum load, and ramp capabilities.

The CCGTs will have the capability to operate at emissions compliant minimum loads down to 35% of output.[48] Additionally, they will be capable of operating at a minimum of 154MWs **[redacted])**[49].

In terms of minimum startup time to full load, from a cold start (greater than 72 hours from shutdown) the CCGTs can achieve **[redacted]** and be at full load in **[redacted]**. This is significantly faster than EKC's existing coal and combined cycle generating facilities, which average **[redacted].**

The CCGTs are expected to be significantly more flexible under warm and hot start conditions. Under warm start conditions (between 8 hours and 72 hours

[48] *See* page 14 of Jason Humphrey's Direct Testimony.
[49] *See* Evergy Confidential Response to Staff Data Request No. 6, contained in Exhibit JTG-14.

since shut down) the CCGTs can be at **[redacted]**, and achieve full load in **[redacted].** Under Hot start conditions (within 8 hours from last shutdown) the CCGTs can be at **[redacted]**, and full load in **[redacted]**.[50]

In terms of ramp capability, once the CCGTs are running at minimum load, they will be capable of ramping **[redacted]**, which is significantly more than Evergy's most capable dispatchable units today.[51]

4. **Stranded Asset Risk**

Q. How would you respond to the assertion that the CCGTs present significant stranded asset cost risk, and that these facilities will be rendered obsolete in just a few years?

A. While there is always a risk involved when you are attempting to predict the future of a generating unit that can last 40 years or more, the reality is that there is not an economically and commercially viable alternative technology available today that can provide long-duration firm dispatchable power when intermittent resources are not available. For this reason, I expect that natural gas generation will be a significant part of Evergy's generation mix for many decades to come.

In SPP's 2023 ITP transmission planning models under Future 2, the assumed retirement age of natural gas units is 48 years old. As a reminder, Future 2 is an emerging technologies scenario, incorporating growth of electric vehicles

[50] *See* Cold, Warm, and Hot Start curves on pg. 659 of Technical Proposal (Section 3 of the PIE Bids) in response to Staff Data Request No. 12 (available upon request due to voluminous nature of the materials).
[51] *See* Evergy Confidential Responses to Staff Data Request Nos. 6 and 44, each contained in Exhibit JTG-14.

and distributed generation as well as higher penetration of renewables and earlier retirement of existing generation. As a percentage of nameplate capacity, the proportion of natural gas in SPP is still 29% in 2042 in Future 2. That is only down from 35% at 2042 in Future 1.

Even in Future 3, in which SPP is planning for all coal-fired generation resources to be retired by 2042, natural gas fired generation is still 19% of nameplate capacity in 2042. In my opinion this demonstrates how the utility industry generally expects that natural gas will continue to be a critical generation resource to support reliability and backup renewables, even in a more renewable heavy future than currently exists today.

5. Risk of EPA Greenhouse Gas Rules

Q In the event that the United States Environmental Protection Agency (EPA)'s Greenhouse Gas (GHG) Rules end up applying to the CCGTs, what options does Evergy have?

A. On March 12, 2025, the EPA announced that it was reconsidering the Clean Power Plan 2.0, as well as the 2009 Endangerment Finding and regulations and actions that rely on that finding.[52] However, if the GHG limits from that rule were enforced, the units would be required to produce no more than 800lbs CO2 per MWh through January 1, 2032, which they will be capable of. After that date, if the units operate at above a 40% capacity factor, then the units will be required to install Carbon Capture and Sequestration (CCS) technology, or co-fire with significant

[52] https://www.epa.gov/newsreleases/epa-launches-biggest-deregulatory-action-us-history

amounts of hydrogen, such that the units would produce just 100lbs of CO_2/MWh. Evergy has stated that CCS technology is unproven and not commercially available, so its compliance plan would likely be limiting the CCGTs capacity factor to 40%.[53]

Q. Did Evergy limit the capacity factor of the CCGT units to 40% in the 2024 IRP modeling?

A. No. In response to Staff Data Request No. 11, Evergy confirmed that it did not model this compliance method in the 2024 IRP.[54] Evergy did model the cost of installing CCS after 2035 in the High Carbon restriction scenario in the 2024 IRP, and it plans to model a full compliance pathway in the 2025 IRP, but it has not produced a model yet that limited the capacity factor to 40% for these units.

Q. What is the modeled capacity factor of these units in the capacity expansion modeling that Evergy has performed?

A. Using the output of the capacity expansion model provided in the supplemental workpapers, the capacity of the CCGT unit averaged **[redacted]** from 2030 through 2035, with a max capacity of **[redacted]**. In the nine years after that, the unit averaged a **[redacted]** capacity factor. In response to KIC DR No. 2-6, Evergy provided modeled capacity factors for the two CCGTs under different market pricing scenarios, different SPP futures, and different levels of carbon restrictions.[55] The five-year average capacity factors were **[redacted]** under all scenarios with no carbon constraints, **[redacted]** under scenarios with carbon constraints, **[redacted]** under all SPP Future 2 scenarios, and **[redacted]** under SPP Future 3

[53] *See* Direct Testimony of Jason Humphrey, at pages 14-15.
[54] *See* Evergy Response to Staff Data Request No. 11, contained in Exhibit JTG-13.
[55] *See* Evergy Confidential Response to KIC Data Request No. 2-6, contained in Exhibit JTG-14.

scenarios. What this analysis says to me is that the carbon-efficient nature of these units leads them to be dispatched more often, likely displacing existing Coal and Gas units on Evergy's system, under carbon constrained futures.

6. **Resource Adequacy (RA) Initiatives at SPP**

Q. Are you aware of any recent RA initiatives at SPP that support the decision to build the CCGTs?

A. Yes. SPP recently filed a request before the Federal Energy Regulatory Commission (FERC) to increase the Planning Reserve margin (PRM)[56] for the 2026 Summer to 16% from 15%, and to implement a PRM of 36% for the Winter of 2026/2027.[57] Subsequently, on February 4, 2025, the SPP Board agreed to increase the PRM for Summer of 2029 to 17%, and 38% for the Winter of 2029/2030. Other recent RA initiatives include the Performance Based Accreditation (PBA)[58] and Effective Load Carrying Capability (ELCC)[59] methodology implementation request, which was filed on February 23, 2024, in Docket No. ER24-1317. Then, the Fuel Assurance[60] implementation request filing

[56] The PRM is the amount of installed capacity that a load serving entity like Evergy is required to have over and above its anticipated peak demand. It is essentially the "cushion" of extra generation that is available to serve customers in the event of unplanned outages on the system or extreme load occurrences that are above planning estimates. SPP sets its PRM levels based on Loss of Load Expectation (LOLE) studies, with the intention of limiting load shed events to no more frequently than 1 day in 10 years, or .1 day per year.

[57] This request was filed on October 15, 2024, in Docket No. ER25-89.

[58] PBA sets the accreditation of thermal generators according to their average performance when called upon to support reliability for the balance of the year, excluding out of management control events.

[59] ELCC sets the accreditation of renewable generators based on the load these generators are anticipated to be able to serve over time, using probabilistic modeling, as renewable penetration levels change (grow) over time.

[60] Fuel Assurance is an adder to the PBA accreditation effort that captures how well thermal generators perform during the top 3% of net load hours (peak load less renewables production), *including* any outages caused by out of management control events that are fuel supply related.

was made on September 3, 2024, in Docket No. ER24-2953. FERC has issued an Order accepting and consolidating the PBA, ELCC, and Fuel Assurance filings, effective October 1, 2025, subject to further paper hearing procedures.

Q. Why are these recent RA initiatives at SPP relevant to the reasonableness of Evergy's decisions to build the CCGTs?

A. SPP's recent RA initiatives are driven by heightened risks to reliability in the SPP footprint that have become more and more evident over the last four years. The changing resource mix, rapid load growth, increasingly extreme weather, and an aging thermal generation fleet are all contributors to the reliability risks that the SPP region is facing today. To combat these risks, SPP has been steadily increasing Summer and Winter PRMs, and has implemented PBA, ELCC, and Fuel Assurance policies. The net result of all of these RA initiatives is that load serving entities like Evergy are being required to produce higher reserve margins at the same time as their existing generation resources, both renewable and conventional, are receiving less accreditation from SPP. The inevitable result is that additional generation needs to be built to maintain reliability in the region.

Q. Did Evergy's 2024 IRP capture these higher PRM requirements and more stringent accreditation standards?

A. Yes. Evergy's 2024 IRP anticipated an increasing Summer PRM, from 17% for the Summer of 2026, growing to 20% by Summer 2029. Evergy also anticipated a Winter PRM of 32% in 2026, growing to 35% in Winter of 2029. As a result, Evergy overestimated the SPP PRM requirement for the Summer, and underestimated the SPP PRM requirement for the Winter. These errors largely offset one another, with expected Summer Capacity requirement being 167 MW too high, and Winter Capacity requirement being 121 MW too low.[61] Additionally, Evergy performed a calculation of the effects of PBA and ELCC on its existing generation fleet. Evergy has yet to include the impacts of Fuel Assurance in its IRP modeling. Staff anticipates that Evergy will include the effects of Fuel Assurance and the updated PRM values in its 2025 IRP.

7. Improved Fuel Diversification

Q. Will the decision for EKC to build the CCGTs result in EKC becoming too heavily exposed to any one fuel source for generation?

A. No. The decision for EKC to build the CCGTs would further increase the diversity of EKC's electric generation fuel sources, moving natural gas from 21.5% of nameplate capacity to 27.97%. The SPP region as a whole currently has approximately 31% natural gas capacity. The decision to build the CCGTs would also move EKC's coal capacity proportion from 40.8% down to 37.4%, compared to the SPP region as a whole which has approximately 21% coal capacity.[62] The comparisons to the SPP region as a whole are not meant to suggest that Evergy should move to the same resource mix as the region. They are provided here for context, in terms of how Evergy's current fuel mix compares to the SPP region as a whole.

---

[61] *See* Evergy Response to Staff Data Request No. 3, contained in Exhibit JTG-13.

[62] *See* Page 4 of Volume 1 from Evergy 2024 IRP, as well as Page 37 of Volume 5, filed May 17, 2024, in the 24-387 Docket. All expressed as a percentage of nameplate.

The following tables represent a before and after view, assuming 710MW of natural gas fired capacity is added to EKC's system:

Before 710 MW of Natural Gas Capacity

Jurisdiction	Capacity by Fuel Type	Capacity (MW)	Capacity (%)
Evergy Kansas Central	Coal	3,209	40.8%
	Nuclear	553	7.0%
	Natural Gas/Oil	1,690	21.5%
	Renewable*	2,418	30.7%
	Total	**7,870**	**100.0%**

*Nameplate Renewables Capacity

After 710 MW of Natural Gas Capacity

Jurisdiction	Capacity by Fuel Type	Capacity (MW)	Capacity (%)
Evergy Kansas Central	Coal	3,209	37.40%
	Nuclear	553	6.45%
	Natural Gas/Oil	2,400	27.97%
	Renewable*	2,418	28.18%
	Total	**8,580**	**100.0%**

Nameplate Renewables Capacity

8. Responsive to Kansas Energy Policy Makers

Q. Why do you consider the decision to build the CCGTs consistent with the energy policy signals expressed by the Kansas Legislature and the Governor of the State of Kansas?

A. During the 2024 Legislative Session, House Bill 2527 passed out of the Kansas House of Representatives with a vote of 119-0, and the Kansas Senate with a vote of 33-2. On April 18, 2024, this bill was signed into law by the Governor. One of the components of this bill was an amendment to the existing predetermination statute, K.S.A 66-1239, to allow a public utility to recover the costs associated with building a new natural gas fired generation facility from customers via a new rate adjustment mechanism (line-item surcharge) on the bill. Importantly, this ratemaking treatment was only called out specifically for a new natural gas fired generation facility. Staff considers this to be a strong signal of policy support by the Kansas Legislature and the Governor of the State of Kansas supporting the decision to build new natural gas fired generation facilities in the State of Kansas, as long as the decision is found by the KCC to be reasonable, reliable, and efficient.

VI. Reliability of the CCGTs

A. Overview

Q. K.S.A. 66-1239 contemplates that the analysis of Evergy's investment plan will consider, in part, if Evergy's investment plan is reliable. What factors have you considered when evaluating the reliability of the CCGTs?

A. In the testimony that follows I will address several factors that Staff considered when evaluating the reliability of the CCGTs, including the ability of the CCGTs to support reliability when weather dependent, intermittent generation is not able to serve customers; the ability of the generators to serve reliably in extreme winter weather, the low forced outage rates of CCGTs, and the SERVM reliability analysis conducted by Evergy in the 2024 IRP.

1. Need for Highly Flexible Dispatchable Generation to Maintain Reliability

Q. What features of the CCGTs do you consider to be highly supportive of reliability?

A. The CCGTs will add highly flexible, dispatchable generation to the system, which offers critical reliability services for customers, like the ability to ramp up quickly when needed, a low minimum run rate, and quick start-up time. Regional reliability organizations like the MRO and SPP have recently and explicitly recognized the critical role that natural gas fired generation serves to maintain the reliability of today's power grid. For example, the MRO's Regional Risk Assessment, published in January of 2025 stated recently:

> Flexible, on-demand resources, currently provided by natural gas-fired generation, are crucial for addressing the intermittent nature of variable, weather dependent generation resources like wind and solar. On-demand resources are capable of filling multi-day supply gaps when variable output is low and will be needed to meet anticipated increases in demand."[63]

Similarly, in its recent Generational Challenge whitepaper, published in the Summer of 2024, SPP stated:

> Our region is increasingly reliant on variable resources. These are generation types, often renewable energy, that vary in how much energy they can provide due to reliance on as-available fuel. While these resources provide environmental and cost benefits when available, they also pose a challenge for grid operators when they are not. Solar power is dependent on time of day and year, and it is reduced by cloud cover or low sunlight.

[63] *See* pages 22-23 of MRO Regional Risk Assessment, January 2025.

> Wind power is dependent on weather patterns, which can shift wildly, and can even be at risk when wind speeds are too high to safely operate. Hydro power is reduced during times of drought or in extreme freezing conditions. All this means renewable output can vary widely. For instance, in just 4 hours, we have seen wind power go from providing over 16,000 megawatts (MW) of energy to less than 2,200 MW.[64]
>
> We have also experienced a period in June 2023 when only 110 MW of energy was produced by the 32,000 MW of nameplate wind capacity existing at that time in the SPP region.
>
> When this happens, other sources of electric energy must be available and quickly ramp up to meet the demand. This is when SPP relies most heavily on dispatchable generation: power sources that have available fuel and can be quickly adjusted to meet the needs of the power grid. Dispatchable power plants can be turned on or off, or their power output can be increased or decreased on demand. This allows them to provide more electricity when demand is high, or less when demand is low.

Q. Both the MRO and SPP have recognized the need for dispatchable generation resources to balance out the generation profile of renewables. Has NERC stated anything specific to the critical importance of natural gas resources for Winter reliability?

A. Yes. NERC has recognized the critical importance of natural gas fired generation for winter reliability. In its recent 2024/2025 Winter Reliability Assessment, NERC stated the following on page 7:

[64] On Feb. 18, 2024, SPP's available wind capacity in the Real-Time Balancing Market went from 16,263 MW at 5:50 a.m. to 2,190 MW at 9:50 a.m., a change of –14,073 MW in four hours.

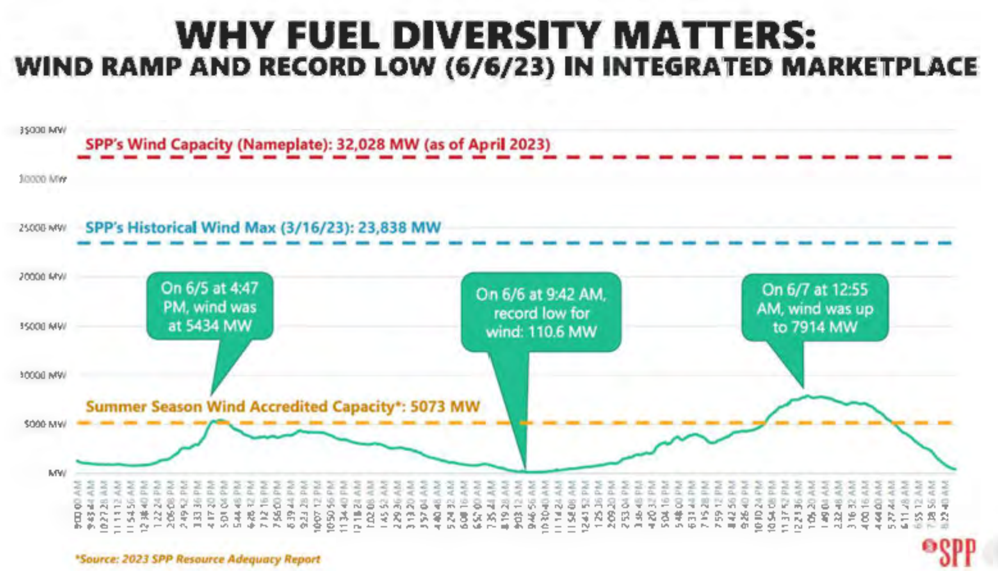
> **Growing winter load underscores the importance of maintaining sufficient dispatchable generation and strong transmission networks.** Winter electric load is growing in most areas as the grid increasingly powers heating, transportation systems, and new data centers. Serving winter load is becoming more challenging and complex as coal-fired and older natural gas-fired generators retire and are replaced by variable and energy-limited resources. Solar resources, which are overwhelmingly the largest share of new resources connecting to the grid, do not provide output during many hours when winter electricity demand is at its highest. New battery resources can extend the output from solar PV for short durations, but winter's longer hours of darkness, cloud cover, and precipitation will push the limits of today's battery storage capabilities and installed energy capacity. Winter resource adequacy depends on dispatchable generation, reliable fuel supplies, and firm transfer agreements.

Additionally, on page 28 of the December 2024 Long-Term Reliability Assessment (LTRA), NERC stated the following:

> Natural-gas-fired generators are and will remain a critical resource for BPS reliability in many areas over the 10-year assessment period, especially during winter. These generators provide many necessary reliability attributes that are exiting the system as traditional generators retire and inverter- based renewable resources take their place in the resource mix. Natural-gas-fired generators are dispatchable and provide the ERSs [Essential Reliability Services] of inertia, frequency response, and ramping flexibility. In winter, when peak demand in most areas occurs during early morning hours, natural-gas-fired generation is at its highest contribution to the resource mix in many areas. Severe winter weather events in 2021 and 2022 provided stark evidence of the critical nature of natural gas as a generator fuel and the importance of secure supplies during times of extreme electricity demand.

Q. How would you respond to stakeholders that have suggested that Evergy should not build any new fossil fuel generation units, and instead, should retire its existing fossil fuel generation units, replacing them with investments in renewables and storage?

A. The reality is that the technology simply does not exist today for Evergy to reliably and affordably replace its entire fossil fuel fleet with solely renewable energy sources and storage. Wind generation, while a great and cost-effective energy resource when it is available, cannot be counted on to always be available. There are times when there is almost no wind online, anywhere in the 14-state region of the SPP. One famous example is from June 6, 2023, at 9:42 AM. As the graphic below shows, during this time there was only 110.6 MW of Wind Generation online in all of SPP, out of an installed nameplate capacity level of 32,038 MW.



On November 18, 2024, I attended a virtual presentation made to the Midwest Governor's Association in which John Moura, NERC's Director of

Reliability Assessment and Performance Analysis, mentioned this example, and then stated that not only did this wind drought hit SPP, but it extended to ERCOT as well. John explained in his presentation that there was only 300 MW online in both regions, out of over 60 GW of installed wind generation.

Q. How does the ELCC capacity credit that renewables receive from SPP factor into this discussion?

A. It is a critical part of the discussion. The ELCC credit that wind, solar, and batteries receive, and the resulting amount of these resources that Evergy would have to build to serve its load reliably is an astronomical number, and there's no way it would be economic to do so today. The average ELCC capacity credit that wind investments are expected to receive in SPP today is approximately 16% in summer and winter. As the level of wind increases, the capacity credit declines to around 13% by 2042. This means that by 2042, all other things being equal, Evergy would have to build seven times as much wind capacity at nameplate (1/.13) to receive the same capacity accreditation as one thermal resource.

For solar, current expectations are that solar investments will get an accreditation as high as 70% in the summer, and 20% in the winter. But, by 2042 that capacity credit is expected to shrink to 17% in the summer and just 5% in the winter. This means that you'd need 6 times as much solar at nameplate in order to replace the capacity of a thermal generation unit in the summer, and 20 times as much solar to replace the capacity of a thermal generation unit in the winter.[65]

[65] This example does not account for any thermal capacity degradation to account for PBA and Fuel Assurance. ELCC accreditation values sourced from Evergy workpaper "Renewable ELCC 2024.xls" workpaper from 24-387 Docket, available upon request.

What the above examples reflect is the immutable reality that the more renewable resources you add to the power grid, the less capability each incremental renewable asset has to serve load reliably. While it is possible to firm up these resources with battery storage, and thus adding accredited capacity, batteries too have a declining ELCC accreditation as their penetration increases as a percentage of installed resources.

Q. Are there recent examples where regional or national reliability organizations have addressed the critical need for dispatchable generation to maintain reliability?

A. There are a number of recent examples where regional and national reliability organizations (MRO, SPP, and NERC) have recognized the critical need to slow and manage thermal generator retirements, as well as the need to take steps now to maintain sufficient dispatchable generation in order to maintain reliability of the electric grid in the years to come.

In the first paragraph of the Executive Summary from the 2024 Long-Term Reliability Assessment, NERC states the following:

> In the 2024 LTRA, NERC finds that most of the North American BPS faces mounting resource adequacy challenges over the next 10 years as surging demand growth continues and thermal generators announce plans for retirement. New solar PV, battery, and hybrid resources continue to flood interconnection queues, but completion rates are lagging behind the need for new generation. Furthermore, the performance of these replacement resources is more variable and weather- dependent than the generators they are replacing. As a result, less overall capacity (dispatchable capacity in particular) is being added to the system than what was projected and needed to meet future demand. **The trends point to critical reliability challenges facing**

> **the industry: satisfying escalating energy growth, managing generator retirements, and accelerating resource and transmission development.**

On Page 8 of the LTRA, NERC expands on the reliability implications of the changing resource mix:

> **Changing Resource Mix and Reliability Implications**
>
> New resource additions continue at a rapid pace. Solar PV remains the overwhelmingly predominant generation type being added to the BPS followed by battery and hybrid resources, natural-gas-fired generators, and wind turbines. New resource additions fell short of industry's projections from the 2023 LTRA with the notable exception of batteries, which added more nameplate capacity than was reported in development last year.
>
> As older fossil-fired generators retire and are replaced by more solar PV and wind resources, the resource mix is becoming increasingly variable and weather-dependent. Solar PV, wind, and other variable energy resources (VER) contribute some fraction of their nameplate capacity output to serving demand based on the energy-producing inputs (e.g., solar irradiance, wind speed). The new resources also have different physical and operating characteristics from the generators that they are replacing, affecting the essential reliability services (ERS) that the resource mix provides. As generators are deactivated and replaced by new types of resources, ERS must still be maintained for the grid to operate reliably.
>
> Natural-gas-fired generators are a vital BPS resource. They provide ERSs by ramping up and down to balance a more variable resource mix and are a dispatchable electricity supply for winter and times when wind and solar resources are less capable of serving demand. Natural gas pipeline capacity additions over the past seven years are trending downward, and some areas could experience insufficient pipeline capacity for electric generation during peak periods.

In the MRO's 2025 Regional Risk Assessment, the top regional risk identified, for the second year in a row, was Uncertain Energy Availability, which MRO ranked as Extreme risk as identified in the graphic below from page 5 of the report.

Table 1: Top Regional Risks

Risk	Priority
Uncertain Energy Availability	EXTREME
Generation Outages During Extreme Cold Weather	HIGH
Nation-State Threats	HIGH
Supply Chain Compromise	HIGH
Malicious Insider Threat	HIGH
Inadequate Inverter-Based Resource and Distributed Energy Resource Performance and Modeling	HIGH

On page 6 of the report, the MRO summarizes Uncertain Energy Availability as follows:

> Uncertain Energy Availability
> Early retirement of thermal resources (e.g., coal and nuclear) that provide on-demand, dispatchable electricity generation creates potential energy shortfalls when replaced with variable, weather-dependent resources that may not be available when needed. This risk is amplified by increasing electricity demand (driven by electrification and the addition of large, single-point loads like data centers) and extreme weather. New approaches to assessing resource adequacy must consider the evolution of energy supply and demand to improve bulk power system planning, operation and investment decisions. Furthermore, the retirement of thermal generation must be carefully managed until adequate replacement energy is available to meet anticipated demand.

The MRO continues on page 13 of the report as follows:

> The risk of Uncertain Energy Availability has been categorized as extreme for the second year in a row. The anticipated addition of large loads like data centers and industrial facilities will strain the current system to meet the energy demand these loads require. This risk is amplified by continued increases in variable, weather-dependent generation (i.e., wind and solar), which is difficult to forecast, and the load variability associated with new end uses of electricity (i.e., electric vehicles and home heating). All of this adds complexity to planning and operating the grid to meet electricity demand when it is needed.

The MRO continues on page 15 of the report as follows:

> Energy policies at the federal, state, and local level impact how the bulk power system is planned and operated and have implications on system reliability. Policies decarbonizing electric generation threaten premature retirement of needed dispatchable resources to meet growing electricity demand and underlie the Uncertain Energy Availability risk in this report.

The MRO continues on page 16 of the report as follows:

> The grid is transforming at a pace that has not been seen since the early twentieth century. The changing mix of resources away from dispatchable, on-demand generation to variable, distributed generation is having dynamic effects on the broader energy risk landscape. Variability in weather dependent energy resources is highlighted in the Uncertain Energy Availability risk in this report, which amplifies the need for new approaches to assessing energy adequacy (or ensuring energy is available when it is needed).

On page 19 of the report, the MRO identifies the Key Drivers of the Extreme Risk of Uncertain Energy Availability:

- Federal, provincial, and state energy policies, along with electric utility companies' own initiatives to decarbonize the generation fleet, have accelerated proposed retirements of dispatchable generation (particularly coal and natural gas).
- Replacement sources of energy are more variable (wind and solar) and produce less energy overall than retiring generation.
- Queues for interconnecting new generation in the MRO footprint are long and are a barrier to bringing additional generation supply online to meet expected future energy demand.
- Systems to store energy from variable resources are commercially limited to short durations (typically 2-4 hours) and are currently unable to address long duration energy shortages (multi-day).
- Increases in large, single points of load (like data centers and industrial developments) are outpacing new generation being added.
- Demand growth from electric vehicles and space heating is difficult to predict and introduces more variability in electricity usage, making it harder to forecast when energy demand will peak.
- Limitations in the ability to transfer bulk amounts of energy over the electric transmission system from where there is ample supply to where it is needed.

On page 19 of the report, the MRO identifies two key actions needed to address the Extreme Risk of Uncertain Energy Availability:

- The retirement of traditional, dispatchable power plants must be carefully managed to ensure a reliable and sufficient supply of electricity. In other words, there needs to be sufficient replacement energy available before these plants are phased out.
- Flexible, on-demand resources, currently provided by natural gas-fired generation, are crucial for addressing the intermittent nature of variable, weather dependent generation resources like wind and solar. On-demand resources are capable of filling multi-day supply gaps when variable output is low and will be needed to meet anticipated increases in demand.

To conclude this section of my testimony, I refer to the opening message from SPP CEO Barbara Sugg, introducing SPP's Generational Challenge whitepaper from Summer of 2024:

> I am concerned now more than ever about the future of our shared electric grid and our ability to provide the reliable and affordable service consumers expect. Our energy system is in the midst of radical change. **Changes in supply, demand, and extreme weather conditions are stressing the limits of energy reliability.**
>
> Demand for electricity is outpacing supply from our generation fleet. Residential and commercial energy use is expected to increase at an unprecedented pace as our nation becomes more electrified and large data centers are added. While a tremendous amount of renewable energy has been added in the SPP region, which provides significant environmental benefits, renewable energy is not always available. We need dispatchable generation for times when the wind isn't blowing and the sun isn't shining, but many of these generators are aging or facing retirement. We also need more transmission to connect new generators to the grid, increase grid security, and get lower-cost energy to consumers.
>
> We are facing an increase in extreme weather events that are causing grid emergencies, tight operating conditions, and risks to human health and safety. In the past, there were only a few weeks in summer when SPP risked running out of energy. Now, we are issuing grid alerts throughout the summer as well as during winter. Our risk of having inadequate supply to meet demand has greatly increased, and grid emergencies are likely to last longer, cause more damage, and increase risks to human health and safety.

2. Winter Reliability of the CCGTs

Q. Are the CCGTs being built to withstand harsh Kansas winter weather?

A. Yes. These CCGTs are being built to withstand winter temperatures as low as -15 Fahrenheit[66] and they will be served by firm natural gas transportation contracts. While Evergy does not have a signed contract for firm gas transportation at this point, it is in involved in negotiations with several intrastate and interstate gas pipelines and does have a reasonable plan to achieve firm transportation.[67] Because this issue will likely remain outstanding by the time the Commission is required to issue an Order, Staff recommends that Evergy be required to submit a compliance filing to the Commission once firm natural gas transportation arrangements have been finalized.

Q. It is widely understood that one of the root causes of the reliability issues experienced during Winter Storm Uri was the freeze offs of natural gas production, and the resulting scarcity of natural gas for home heating and electricity production. Have there been improvements in the ability of the natural gas delivery system since Winter Storm Uri?

A. Yes. Recent weather events have proven that there have been significant improvements since Winter Storm Uri in the ability of the natural gas and electric industries to maintain reliability during extreme winter weather events. For

[66] *See* Evergy Response to Staff Data Request No. 15, contained in Exhibit JTG-13.
[67] *See* Direct Testimony of Evergy witness Kyle Olson and the Evergy Highly Confidential Response to Staff Data Request No. 18. This response is contained in Exhibit JTG-15.

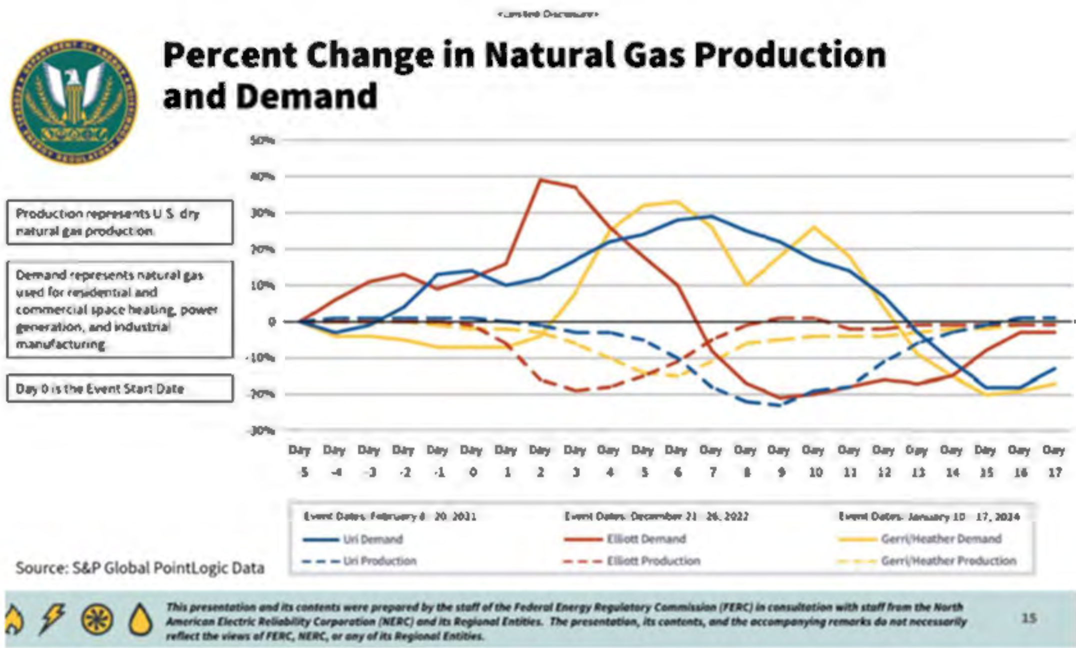
example, NERC stated the following on pages 7 and 8 of its most recent Winter Reliability Assessment:

> **Regulatory and industry initiatives to address reliability issues from winter storms Elliott and Uri make the grid better prepared for the upcoming winter.** Cold weather reliability standards, generator weatherization efforts, and early commitment of generators in advance of freezing temperatures contributed to fewer generator outages in 2023–2024 winter storms compared to Winter Storm Uri (2021) and Winter Storm Elliott (2022).[68] More accurate weather and load forecasting and better communication among natural gas suppliers, Generator Operators (GOP), and electric grid Balancing Authorities (BA) and Reliability Coordinators (RC) also helped maintain the supply of electricity…
>
> …During the January 2024 cold snap, there were no instances of system operator-initiated load shed, and generators reported fewer derates/outages as compared to past winter storms. Impacted areas noted improved winter preparedness, proactive generator commitment, improved short-term load forecasting, improved gas generator stability due to variable (i.e., non-ratable) fuel supply methods, and incorporation of operating limitations into operating plans. Natural gas and electric entities also noted positive steps taken to improve preparation for extreme cold weather, highlighting improved communication and coordination.

The following graphic from the FERC/NERC review of Winter Storms Gerri and Heather (January 2024) demonstrates how natural gas production has improved from Uri to Elliott to Geri/Heather. Despite extremely cold weather and very high

[68] *See* January 2024 Arctic Storms System Performance Review Presentation, FERC Open Meeting, April 25, 2024 https://www.ferc.gov/news-events/news/presentation-system-performance-review-january-2024-arctic-storms

demand for natural gas during these storms, production fell by less in each of these storms than the preceding storm.



Additionally, Staff is aware of at least one major natural gas producer, BPX Energy, a subsidiary of British Petroleum, that has electrified and greatly improved the winterization of 95% of its natural gas production facilities in the Permian Basin.[69] This is important because 10% of the gas supply for the Southern Star pipeline is currently sourced out of the Permian, and Southern Star is considering additional supply opportunities for up to 1BCF/day of additional supply to its pipeline.[70]

[69] See Staff Exhibit JTG-7.
[70] See Staff Exhibit JTG-8.

3. Forced Outage Rates of the CCGTs

Q. What are the expected forced outage rates of the CCGTs?

A. The CCGTs are expected to have very low forced outage rates. In a December 2024 SPP SAWG meeting, SPP reported that CCGTs within SPP's territory have better Demand Equivalent Forced Outage Rate (EFORd)[71] and Equivalent Forced Outage Factor (EFOF)[72] reliability values, both in summer and winter, than Combustion Turbines (CTs), or Reciprocating Internal Combustion Engines (RCIPs), even when these other generation types have on-site liquid fuel storage.[73] The results of SPP's survey are reproduced here: (next page)

[71] EFORd in this context measures the likelihood of a generating unit being unavailable to meet the demand to serve load, due to a forced or unplanned outage, and is used to determine the capacity accreditation for SPP's PBA methodology.
[72] EFOF in this context refers to the inability of a generating unit to serve load during the top 3% of net load hours, because of a forced outage (including forced outages that are fuel related), even if they are outside of management control. This is used to determine capacity accreditation for SPP's Fuel Assurance methodology.
[73] *See* Attachment JTG-1, December 2024 SAWG Presentation of On-Site Fuel Survey Results.

Option 3A – On-site Liquid Fuels

Category	On site Liquid Fuel Storage	Season	Unit Capability Range	Number of Units	Capacity Claimed	Weighted EFORd	Weighted EFOF
Conventional Hydroelectric	N/A	Summer	10.8 - 102	58	2,812	0.4%	N/A
		Winter	10.8 - 102	58	2,842	0.5%	0.1%
Hydroelectric Pumped Storage	N/A	Summer	48 - 48	6	258	7.7%	N/A
		Winter	48 - 48	6	258	7.3%	19.1%
Combined Cycle (Natural and other gas)	Yes and No	Summer	19.8 - 390	81	12,103	6.9%	N/A
		Winter	19.8 - 390	75	11,083	6.8%	8.5%
Combustion Turbine (Fuel Oil, Natural Gas, Kerosene)	No	Summer	3.5 - 203	106	7,286	8.4%	N/A
		Winter	3.5 - 203	106	7,407	20.9%	19.7%
	Yes	Summer	15.1 - 178.5	83	3,784	13.0%	N/A
		Winter	15.1 - 178.5	83	3,970	16.6%	8.7%
Reciprocating Internal Combustion Engine	No	Summer	0.5 - 22.10	104	741	7.4%	N/A
		Winter	0.5 - 22.10	104	731	11.2%	9.4%
	Yes	Summer	0.10 - 9.3	438	906	7.6%	N/A
		Winter	0.10 - 9.3	431	898	9.9%	9.4%
Steam Turbine (Coal)	Yes and No	Summer	16.5 - 922.5	63	22,753	9.2%	N/A
		Winter	16.5 - 922.5	62	22,542	11.0%	11.1%
Steam Turbine (Natural gas and other)	Yes and No	Summer	12.5 - 572.3	57	9,673	14.0%	N/A
		Winter	12.5 - 572.3	57	9,441	13.3%	11.4%
Steam Turbine (Nuclear)	N/A	Summer	801 - 1267	2	1,945	1.1%	N/A
		Winter	801 - 1267	2	1,987	1.9%	1.3%

The results of SPP's survey for CCGTs is an EFORd of 6.9% for Summer and 6.8% for Winter. These forced outage factors are lower than any other class of generation, except Nuclear and Hydroelectric. The summer forced outage factors are substantially better than existing CTs and RECIPs in SPP. During the Winter, the CCGTs in SPP maintain an EFOF of 8.5%, which is even lower than CTs (8.7%) or RECIPs (9.4%) with on-site fuel storage.

While these survey results are only indicative because we do not know key variables like the age or condition of each of these plants, Staff is aware of an existing CCGT in SPP with consistent forced outage factors less than 3%, so we contend that these numbers are reasonable enough to be relied on for resource planning purposes.

4. SERVM Modeled Reliability Results

Q. Is there additional evidence supporting the reliability of Evergy's preferred resource plan, including the CCGTs?

A. Yes. Section 18 of Evergy's 2024 IRP analysis evaluated the reliability of the preferred resource plan using the Strategic Energy and Risk Valuation Model (SERVM) software.[74] These results showed that Evergy's preferred resource plan would exceed the industry standard loss of load expectation (LOLE) metric of .1 (one day in ten years, or .1 day per year). These results are far superior to the scenario in which the capacity expansion model was only allowed to select renewables and energy storage resources, with that plan producing LOLE results 3 times higher than the industry standard.[75]

VII. Efficiency of the CCGTs

A. Overview

Q. K.S.A. 66-1239 contemplates that the analysis of Evergy's investment plan will consider, in part, if Evergy's investment plan is efficient. What factors have you considered when evaluating the efficiency of the CCGTs?

A. In the testimony that follows I will address several factors that Staff considered when evaluating the efficiency of the CCGTs, including the fuel efficiency of the units, the expected gas purchasing practices for the units, the 2024 IRP and updated capacity expansion modeling results, the competitive bidding processes used by Evergy, Staff's evaluation of these units through the S&P Global Intelligence

[74] *See* https://www.astrape.com/servm/ for an explanation of the capabilities and attributes of the SERVM platform.
[75] See SERVM Reliability analysis, pages 136-140 in Volume 5 of Evergy's 2024 IRP.

Power Evaluator software, a comparison of the LCOE of the CCGTs to the most recent Lazard LCOE estimates, and the carbon efficiency of the CCGTs.

1. **Fuel Efficiency of the CCGTs**

Q. How fuel efficient are the CCGTs expected to be?

A. These CCGTs are expected to be highly fuel efficient, in terms of the ability to generate one megawatt hour (MWh) of electricity per million British Thermal Units (MMBtus). These CCGTs will be able to generate one MWh of electricity with just **[redacted]** MMBtus of natural gas,[76] an efficiency gain of **[redacted]** compared to the average gas unit in Evergy's fleet, **[redacted]** from the least efficient gas unit in the fleet, and **[redacted]** more efficient that the most efficient gas unit in the fleet.[77]

This means that during periods of relative scarcity of natural gas, as was experienced during Winter Storm Uri, these CCGTs will be able to produce electricity by burning approximately half of the fuel required from the least efficient unit in Evergy's fleet, and 40% as much fuel from the average natural gas unit in Evergy's fleet. That level of efficiency will improve the reliability of the entire interconnected gas and electric system in Kansas. The low heat rate of these units will also act to better insulate customers from price spikes in natural gas, because the units use less of the commodity to produce electricity.

[76] Equivalently, **[redacted]** British thermal units (BTUs) required to produce one kWh of electricity.
[77] *See* Evergy Confidential Response to CURB Data Request No. 17 in Docket No. 24-EKCE-387-CPL, contained in Exhibit JTG-14.

2. Gas Purchasing Practices for the CCGTs

Q. Has Evergy established a gas purchasing plan that will allow the CCGTs to have access to stable priced gas over time, if they operate in a baseload fashion?

A. Not yet, although Evergy has acknowledged the need to develop a gas purchasing plan as stated on page 31 of Kyle Olson's Direct Testimony. Mr. Olson states that he expects that the plan would be similar to the strategy Evergy uses to procure coal for its coal-fired generators today. Mr. Olson also states that he anticipates utilizing a variety of procurement methods, including long-term fixed price purchases, and index based Inside FERC prices, which would minimize customer exposure to spot natural gas pricing.

In response to New Energy Economics (NEE) Data Request No. 3, Evergy provided additional details surrounding its anticipated natural gas procurement strategy and plan. Evergy explained its intention to establish a laddered procurement of physical natural gas at multiple intervals, with multiple counterparties, prior to spot purchases. Evergy also explained that it would use its **[redacted].**

Q. What is your recommendation with regard to the formulation of Evergy's Natural Gas purchasing plan for the CCGTs?

A. I recommend that Evergy be required to collaborate with Staff and CURB during the development of this plan, and to file the results of the plan in a compliance filing at the KCC. Thereafter, Evergy should be required to meet at least annually with Staff and CURB to discuss potential revisions to the Gas Purchasing Plan. Additionally, should the addition of the CCGTs materially revise Evergy's current Natural Gas Hedging Plan, Staff expects Evergy to collaborate with Staff and CURB on the particulars of a revised Hedging Plan.

Q. Are you aware that NEE criticized Evergy's forecast of natural gas costs during the 2024 IRP?

A. Yes. NEE's comments in response to Evergy's 2024 IRP contained these criticisms, from pages 18 to 21 of their report[78]. One of these criticisms was that "[p]rice forecasts such as Evergy's can also fail to account for regional specificity." NEE explained that the company's description of its forecasting methodology suggested it was "likely" forecasting the price at the Henry Hub, which did not reflect the idiosyncrasies of local markets, which tend to reflect greater volatility and higher realized prices. To support these claims, NEE compared the historical delivered price of natural gas at Evergy plants, using data reported to the EIA on Form 923, to the price of natural gas reported at the Henry Hub, concluding that delivered prices were higher and more volatile than Henry Hub prices, especially

[78] *See* Comments of the Council for the New Energy Economics, pp. 18-21, Docket 24-387 (Oct. 14, 2024).

during times of high winter consumption. Ultimately this issue remained unresolved, and the Commission Order on the IRP found that it would consider evidence relating to this issue to the extent it is relevant in this Docket. [79]

Q. Do you share the same concerns as NEE about Evergy's natural gas price forecasts as included in the 2024 IRP?

A. No. Staff has been able to confirm, upon receipt of Staff Data Request No. 40, that the natural gas price forecast used in Evergy's 2024 IRP was based on local natural gas prices, accounting for the basis differential between Panhandle Eastern and the Henry Hub location. This is a reasonable basis upon which to forecast local natural gas prices.

Additionally, the response to Staff Data Request No. 41 confirmed that the delivered natural gas prices Evergy reports on EIA Form 923 includes gas commodity cost, pipeline reservation fees, and pipeline transportation costs. Accordingly, it is inaccurate to compare these EIA reported "delivered" natural gas prices to the 2024 IRP gas price forecast which does not contain these reservation fees and transportation costs. The response to Staff Data Request No. 42 confirmed that the costs of firm natural gas transportation was modeled separately from the commodity cost in the 2024 IRP.

Lastly, Evergy's historical natural gas costs, as reported through EIA Form 923 or any other source, would reflect the reality that Evergy's gas purchases today

[79] *See* Order Finding Evergy's 2024 IRP Complied with Requirements of Capital Plan Framework, ¶ 18, Docket 24-387 (Jan. 30, 2025). https://estar.kcc.ks.gov/estar/ViewFile.aspx/20250130102915.pdf?Id=1316831d-6bf6-4f35-a6cc-d7263310001a

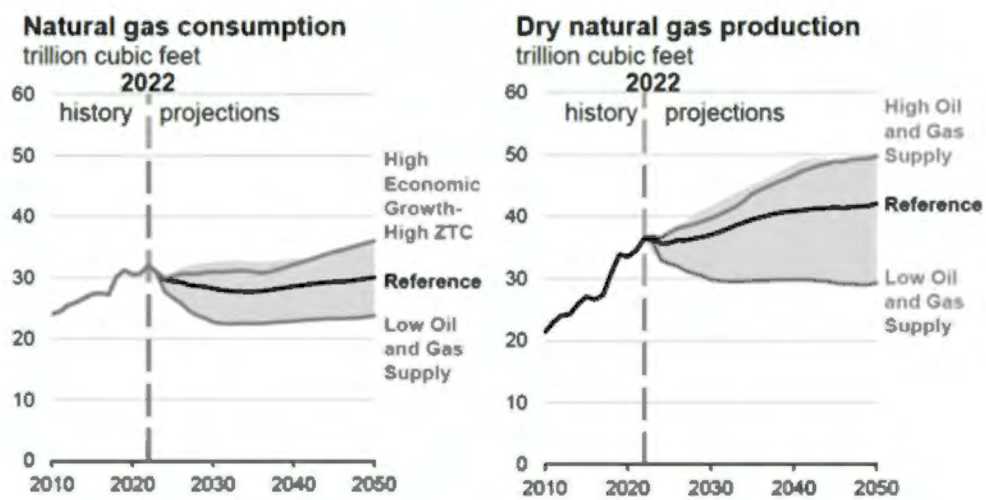
are largely reactive, daily spot price purchases, as confirmed on page 31 of Kyle Olson's Direct Testimony, which is reflective of the "peaking" nature of Evergy's current natural gas fleet. Once Evergy develops a revised gas purchasing plan for the units, Evergy's gas purchases for the CCGTs would be expected to be less volatile, and more reflective of average regional natural gas prices over time.

Q. Should the Commission be concerned about the long-term supply and demand for natural gas for these CCGTs?

A. It would not be unreasonable for the Commission to question the long-term supply and demand of natural gas, and the ultimate impact on fuel costs for the CCGTs. As of February 19, 2025, there were 157 new natural gas fired generating facilities being planned for construction in the United States, representing 79.1GW of new capacity.[80] For sure, there is likely to be a surge in demand for natural gas for electricity consumption in this country. But the natural gas market has shown the ability to grow production levels commensurate with demand increases before. For example, in 2005, average daily production of dry natural gas in the US was 48.4 billion cubic feet (Bcf)/day. In January of 2021, right before Winter Storm Uri, the total dry natural gas production in the United States was a little over 92.6 Bcf/day. By December of 2024, that number had increased to 105.7 Bcf/day, on average.[81] In March of 2023, the United States Energy Information Administration (EIA) produced the 2023 Annual Energy Outlook (AEO).[82] In that outlook, the EIA stated

[80] *See* US Power Sector plans 80GW of new fossil fuel capacity, 159 new plants, February 19, 2025, S&P Market Intelligence, Commodity Insights. Attached as Exhibit JTG-9.
[81] *See* Monthly US Dry Natural Gas Production levels, at https://www.eia.gov/dnav/ng/hist/n9070us2m.htm
[82] This is currently the most recent AEO available, because the 2024 AEO wasn't published, and the 2025 AEO is not yet available on the EIA website.

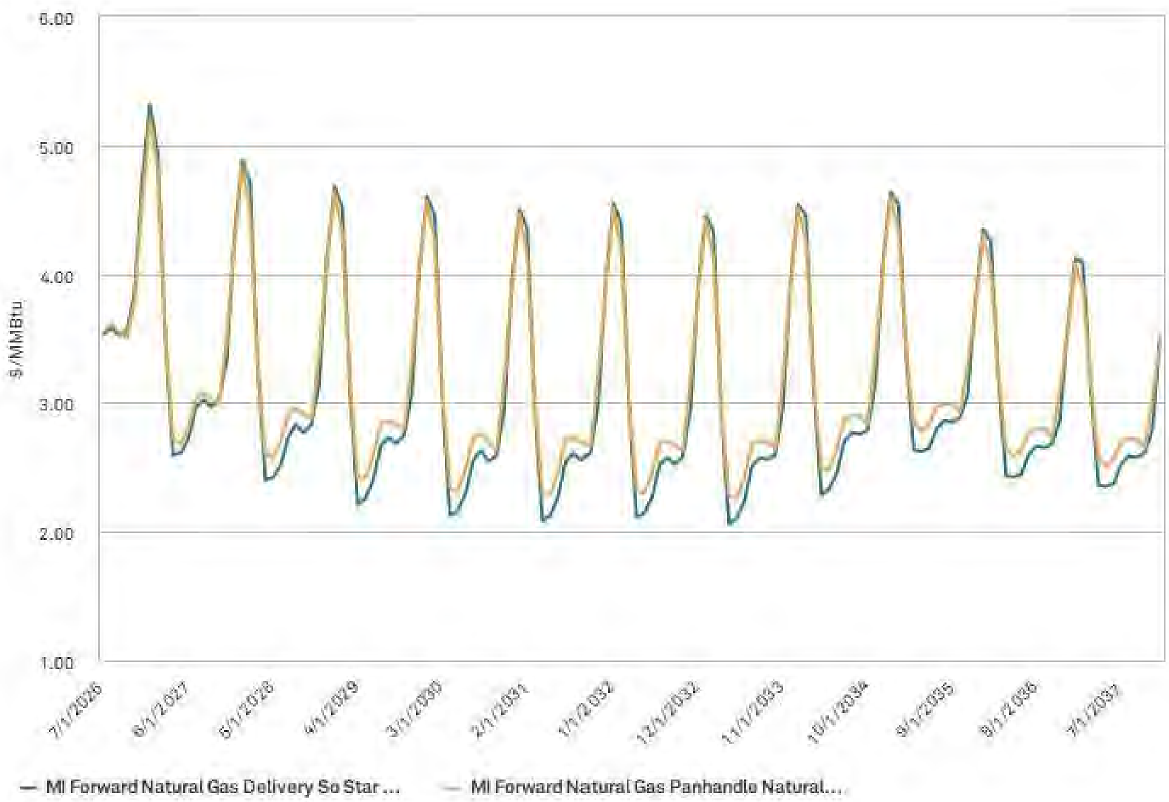
that across all cases examined, domestic production outpaced domestic consumption of natural gas through 2050, as demonstrated through the following graphic: (next page)



Q. Are there any other indications that you can point the Commission to regarding the likely long-term stability of natural gas prices in this part of the Country?

A. Yes. On March 12, 2025, using S&P Global Market Intelligence, I accessed a forward market price curve for local delivery of natural gas at the Southern Star (SS) delivery point and the Panhandle Eastern (PE) delivery point with forward prices extending through 2037.[83] The result was normal seasonal pricing patterns for both PE and SS priced gas, with higher winter prices and lower summer prices, and all prices after 2029 forecast to be under $5/MMBtu, as seen in the chart below.

[83] *See* Staff Exhibit JTG-15.



3. Updated Capacity Expansion Modeling Results

Q. How does the updated capacity expansion modeling results provided in this Docket indicate that the CCGTs are efficient?

A. The CCGTs were selected as part of the updated 2024 IRP analysis that Evergy conducted in support of this Application. This analysis was provided on pages 24 and 25 of Evergy witness Cody VandeVelde's Direct Testimony, and Mr. VandeVelde's Supplemental Direct Testimony on pages 7 and 8. The capacity expansion modeling used by Evergy selects the least cost portfolio of resources, given a certain set of constraints, assumptions, and scenarios. When Evergy conducted its capacity expansion modeling using the updated costs of the CCGTs, the model still selected one full 710 MW combined cycle facility by 2030. This is evidence that the two halves of each CCGT that are the subject of this proceeding, totaling 710 MW, are efficient.

Q. Was Evergy's preferred plan from the 2024 IRP the lowest cost plan on an NPVRR basis?

A. No. The preferred resource plan in the 2024 IRP was not the lowest cost plan, it was actually the third lowest cost plan. Mr. VandeVelde explains on page 14 of his Direct Testimony that the only plans that had a lower NPVRR was the plan that delayed the retirement of Jeffrey 2 from 2032 to 2039 and the plan that did not reflect the manual adjustment of the timing of one of the CCGTs to sync up with Evergy Missouri West's building of a CCGT. The preferred plan NPVRR was .08% higher than the lowest cost plan in the 2024 IRP, which was later updated to 1.4% higher in response to Staff Data Request No. 1R.[84] The later analysis was prepared at Staff's request, and it only reflected an update to the cost, size, and heat rates of both CCGTs and CTs in the analysis. Accordingly, it is not a complete update of the 2024 IRP, but it does serve as a useful reference case to see how the NPVRR of the preferred portfolio changed as a result of the increase in cost of the CCGTs.

[84] The response to this Data Request is voluminous, so it is not attached, but is readily available upon request.

Q. If the preferred plan was not the least cost plan under the 2024 IRP, why is Staff supporting the decision to build the CCGTs at this time?

A. The preferred plan, which includes the CCGTs, was very close to the lowest cost plan in the 2024 IRP analysis. The least cost plan under the 2024 IRP was entitled ABAA, and that plan called for a delay of the retirement of Jeffrey Unit 2 to 2039, from 2032, and doubling the level of new solar build from 2027 through 2032, for a total of 1500 MW of new solar over that time frame. Also, the plan called for a delay of any new thermal builds until 2032, when a CT would be built instead of the CCGTs. Given the delay in the thermal build and aggressive solar buildout of plan ABAA, Staff would not likely support that plan at this time.

Q. Why would Staff likely not be supportive of plan ABAA at this time?

A. Staff would be concerned if Evergy's plan was to delay any new thermal generation build an additional three years to 2032 and instead build an extra 750 MW of utility scale solar over the next five years. We take this view because of the degree of recent local opposition to utility scale solar projects, the litigation that frequently ensues when a county does permit a utility scale solar project, and the extreme uncertainty surrounding the future of federal production tax credits for solar at this time. Until clarity is reached on some of these critical issues, we would be unlikely to recommend support for a resource plan that relies so heavily on the buildout of utility scale solar generation.

4. Efficiency of Construction and Market Operations

Q. Has Evergy taken action to ensure that the CCGTs will be efficiently constructed and operated in the wholesale markets?

A. Yes. Evergy described its competitive solicitation processes for the selection of the major construction and equipment costs of the CCGTs in response to CURB Data Request No. 18:

> Evergy has run a competitive process at every step of this project. The selection of advanced class machines was made on the anticipation of the lowest cost per kilowatt resource with the highest efficiency and the most flexibility for customers. The owner's engineer was selected through a competitive RFP, the gas turbine provider was selected from a competitive RFP to all major gas turbine suppliers, the generator-step-up transformers were selected through a competitive RFP and the EPC is being selected through a competitive RFP.
>
> Every phase of the project has been advanced through a competitive process and is striving for the best balance of cost, reliability, execution, long-term flexibility, and ability to meet market mission. The supply and demand forces affecting the market for firm-dispatchable power have caused prices to increase but, as evidenced by the recent pricing from Basin Electric and similar pricing from other referenced utilities, Evergy's prices are in line with or slightly better than the broader market today.

Staff also inquired into Evergy's plan for offering these CCGTs into the SPP IM. In response to Staff Data Request No. 57, Evergy stated the following:

> Generally, Evergy will offer the CCGTs into the SPP Integrated Marketplace daily, allowing SPP to both economically commit and dispatch the resources. From time to time, operational and/or environmental reasons may require short periods of self-commitment.

5. Evaluation of the CCGTs with S&P Global's Power Evaluator

Q. Please describe the analysis that Staff performed to evaluate the CCGT assets through the S&P Global Power Evaluator software platform?

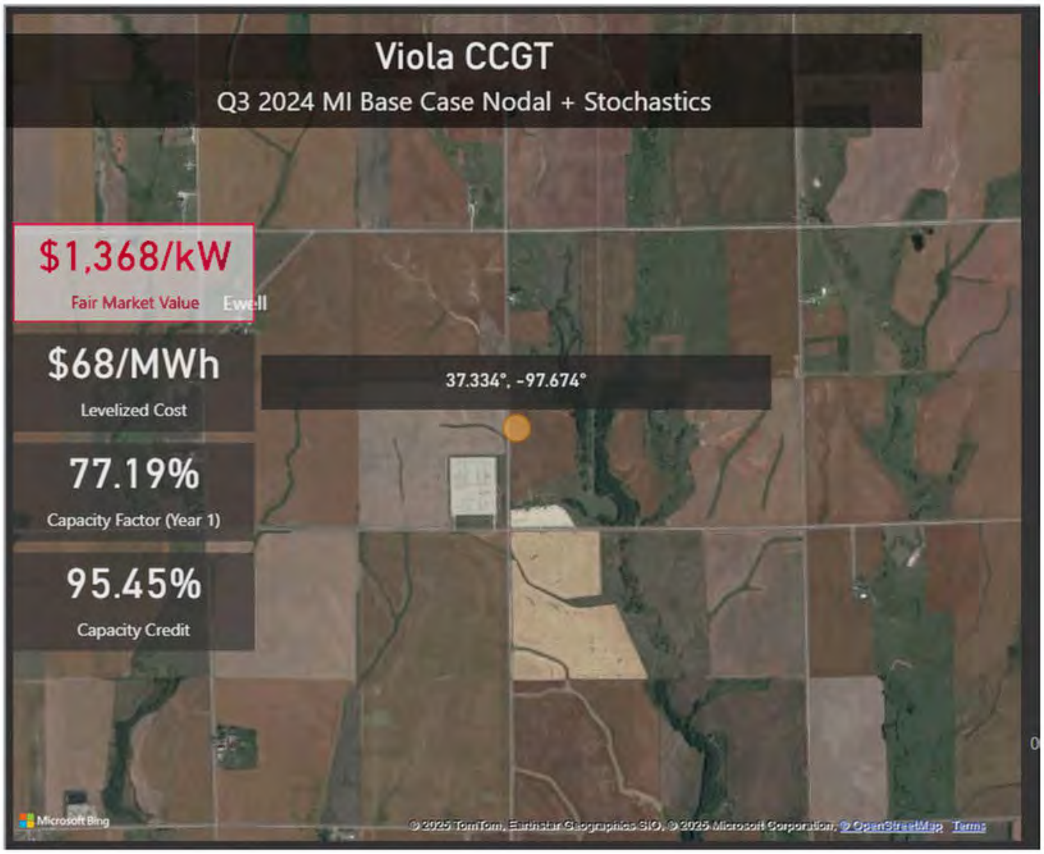
A. As part of Staff's evaluation of the CCGTs in this proceeding, Staff contracted with S&P Global Market Intelligence to gain access to the Power Evaluator software platform. This software allows the user to simulate the interconnection of a new generating plant at a specific geographic location, providing locational marginal price-level economic and reliability analysis of a prospective power plant.[85] Using Power Evaluator, Staff simulated the addition of the Viola CCGT at the exact physical location where Evergy intends to construct this resource and interconnect to the transmission grid.

The result was an anticipated 77.19% capacity factor in year 1, evaluated through economic dispatch simulation on an hourly basis. Another output of the simulation was a Levelized Cost of Energy (LCOE) calculation for the Viola CCGT, which was estimated at $68/MWh.

A screenshot of one of the model outputs for the Viola CCGT is provided here: (next page)

[85] See Staff Exhibit JTG-10 for a description of Power Evaluator's capability and the particulars of the modeling architecture and methodology.

Power Evaluator



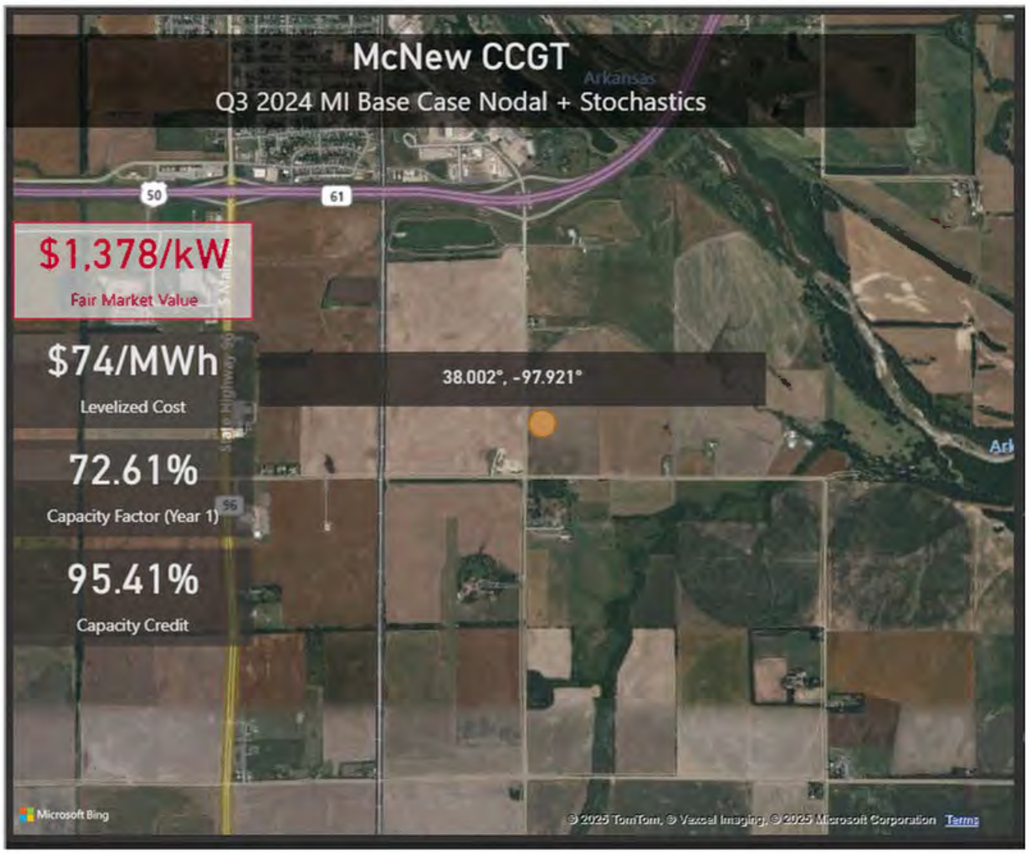
The following table contains a list of the details and assumptions used to model the Viola CCGT through Power Evaluator. Because many of the specific assumptions here pertain to variables which are considered confidential by Evergy, elements of the table below are considered confidential, and are therefore redacted from my public testimony.

(Capital Expenditure, Heat Rate, Fixed and Variable O&M is Redacted)

_	Value
Location	Sumner County, KS
Coordinates	37.334°, -97.674°
Capacity	710 MW
Prime Mover	Combined Cycle
Fuel	Gas
Online Year	2029
Node	WRVIOLA7UNFLATRDG2_TSA
Modelling Zone	SPP_N
Economic Life	48 years
Capital Expenditure	[redacted]
Interconnection Cost	$0
Capacity Factor (Year 1)	77.19%
Availability Factor (Year 1)	89.40%
Capacity Credit	95.38%
Heat Rate	[redacted]
Carbon Emission Rate	118 lbs/mmBtu
Cost of Equity	10.00%
Debt Interest Rate	5.00%
Debt Tenor	20 years
Target DSCR	1.40
Fixed O&M (Year 1)	[redacted]
Variable O&M (Year 1)	[redacted]
Fuel Cost (Year 1)	$3.07/mmBtu
Property Tax	1.00%
Insurance	0.10%
Federal Tax	21.00%
Depreciation	MACRS 15
IRA Energy Community?	No
County	Sumner County, KS
State	Kansas
ISO Zone	[SPP] Zone 2
ISO/RTO	SPP
Balancing Authority	Southwest Power Pool Inc
NERC Subregion	Midwest Reliability Organization - U.S.
NERC Region	Midwest Reliability Organization
Interconnect	Eastern Interconnect
Country	United States

Staff also used Power Evaluator to evaluate the addition of the McNew CCGT facility. This facility was estimated to have an 72.61% capacity factor in the first year, with a LCOE estimated at $74/MWh. A screenshot of one of the model outputs for the McNew Facility is provided here:

Power Evaluator



The following table contains a list of the details and assumptions used to model the McNew CCGT through Power Evaluator. Because many of the specific assumptions here pertain to variables which are considered confidential by Evergy, elements of the table below are considered confidential, and are therefore redacted from my public testimony.

(Capital Expenditure, Heat Rate, Fixed and Variable O&M is Redacted)

_	Value
Location	Reno County, KS
Coordinates	38.002°, -97.921°
Capacity	710 MW
Prime Mover	Combined Cycle
Fuel	Gas
Online Year	2030
Node	WR_HEC_GT4
Modelling Zone	SPP_N
Economic Life	48 years
Capital Expenditure	[redacted]
Interconnection Cost	$0
Capacity Factor (Year 1)	72.61%
Availability Factor (Year 1)	89.40%
Capacity Credit	95.17%
Heat Rate	[redacted]
Carbon Emission Rate	118 lbs/mmBtu
Cost of Equity	10.00%
Debt Interest Rate	5.00%
Debt Tenor	20 years
Target DSCR	1.40
Fixed O&M (Year 1)	[redacted]
Variable O&M (Year 1)	[redacted]
Fuel Cost (Year 1)	$2.95/mmBtu
Property Tax	1.00%
Insurance	0.10%
Federal Tax	21.00%
Depreciation	MACRS 15
IRA Energy Community?	No
County	Reno County, KS
State	Kansas
ISO Zone	[SPP] Zone 4
ISO/RTO	SPP
Balancing Authority	Southwest Power Pool Inc
NERC Subregion	Midwest Reliability Organization - U.S.
NERC Region	Midwest Reliability Organization
Interconnect	Eastern Interconnect
Country	United States

The following bullets describe the customized values that Staff changed in the Power Evaluator model for the Viola and McNew CCGTs.

- The economic life of both CCGT units was estimated at 48 years, based on the SPP Future 2 assumption from the 2023 ITP;
- The estimated capital cost for Viola was set to **[redacted]**, which is inclusive of interconnection costs and is the closest value that the model would support compared to the most recent estimated capital cost for Viola of **[redacted]**;
- The estimated capital cost for McNew was set to **[redacted]**, which is inclusive of interconnection costs and is the closest value that the model would support compared to the most recent estimated capital cost for this unit of **[redacted]**;
- The Fixed O&M value was set to **[redacted]** for Viola and **[redacted]** for McNew, which represents Evergy's estimated values for each unit as provided in the workpapers Evergy provided in this Docket, adjusted to include firm gas transportation costs;
- The Variable O&M values for both units was changed to **[redacted]** which reflects Evergy's estimated values from the 2024 IRP Docket;
- The heat rate, installed size, geographic location, online year, tax depreciation method, property insurance and property tax values were all set to the closest value we could support as allowed by the model parameters for each unit; and

- Staff assumed an ROE of 10%, a Cost of Debt of 5%, and a capital structure of 50% Equity 50% Debt for purposes of this model, which only allows refinement to the nearest whole percentage.
- The Capacity Factor, Availability Factor, and Capacity Credit are all model calculated values. Staff also allowed the model to estimate fuel cost for both units.

Q. What conclusion should the Commission draw from your testimony pertaining to Staff's use of the Power Evaluator software to evaluate the CCGTs?

A. The estimated LCOE figures calculated by the Power Evaluator software compare favorably to the average LCOE of $76/MWh reported for a new CCGT by the Lazard 2024 LCOE report, which also provided a range of LCOEs for new CCGTs, estimated to be $45 to $108/MWh.[86] Additionally, the estimated capacity factors indicate that the CCGTs will be economic units that will be frequently dispatched into the SPP IM.

I recommend that the Commission view the above results as indicative, and generally supportive, of the decision to build these CCGT units in the configuration and locations that have been selected. The LCOE and Capacity Factor calculations performed by the software are helpful data points to validate the work performed by Evergy in the IRP Docket and through the updated capacity expansion modeling performed for this Docket.

[86] Lazard 2024 LCOE Report attached as Exhibit JTG-2.

Q. Why did Staff contract with S&P to gain access to the Power Evaluator software?

A. Just as this Docket was filed, I saw an announcement from S&P Global promoting the use of this software to investment professionals, project developers, and regulators. Staff requested a demonstration and were immediately impressed with the capability of the software to evaluate the reasonableness and financial viability of selected potential generation assets. Our hope was that we would be able to use the platform to provide the Commission an alternative indicative view of the reasonableness and economic efficiency of the CCGTs. Overall, we are pleased with the decision to purchase access to the platform and be able to include these results in this testimony.

6. Carbon Efficiency of the CCGTs

Q. Did Staff conduct an evaluation of the efficiency of the CO2 emissions levels of the CCGTs?

A. Yes. While the Commission is not an environmental regulator, Staff is aware that there are several intervenors in this proceeding for which CO2 emissions are a major concern, and there were several members of the public who addressed this specific issue in their comments to the Commission at the Public Hearing in this Docket. Accordingly, we conducted discovery about the carbon emissions intensity of the CCGTs compared to Evergy's existing coal and natural gas fired generators

In response to Staff Data Request No. 43, Evergy stated that the CCGTs would be capable of CO2 emissions levels as low as 800 pounds of CO2 per MWh.

It also provided the CO_2 emissions levels for Evergy's existing generation units. That list is provided here:

Existing Generating Units
The following emission rates are all in pounds per megawatt-hour gross (lb/MWh-gross). The emission rates are based on a three-year (2022 – 2024) average for each unit.

Jeffrey Energy Center Unit 1 – 1,943
Jeffrey Energy Center Unit 2 – 2,090
Jeffrey Energy Center Unit 3 – 2,046
La Cygne Generating Station Unit 1 – 2,016
La Cygne Generating Station Unit 2 – 2,063
Lawrence Energy Center Unit 4 – 2,157
Lawrence Energy Center Unit 5 – 1,963
Gordon Evans Energy Center Combustion Turbine 1 – 1,473
Gordon Evans Energy Center Combustion Turbine 2 – 1,528
Gordon Evans Energy Center Combustion Turbine 3 – 1,311
Emporia Energy Center Combustion Turbine 1 – 1,471
Emporia Energy Center Combustion Turbine 2 – 1,499
Emporia Energy Center Combustion Turbine 3 – 1,569
Emporia Energy Center Combustion Turbine 4 – 1,537
Emporia Energy Center Combustion Turbine 5 – 1,377
Emporia Energy Center Combustion Turbine 6 – 1,407
Emporia Energy Center Combustion Turbine 7 – 1,347
Hutchinson Energy Center Combustion Turbine 1 – 2,601
Hutchinson Energy Center Combustion Turbine 2 – 2,574
Hutchinson Energy Center Combustion Turbine 3 – 2,690
Hutchinson Energy Center Combustion Turbine 4 – 9,937
Spring Creek Energy Center Combustion Turbine 1 – 1,593
Spring Creek Energy Center Combustion Turbine 2 – 1,601
Spring Creek Energy Center Combustion Turbine 3 – 1,589
Spring Creek Energy Center Combustion Turbine 4 – 1,598

Excluding the value for Hutchinson Energy Center 4, which appears to be an error or an outlier, I calculated that the CCGT CO_2 emissions will be a 61% reduction from the average coal-fired generation unit in EKC's fleet today, and a 53% reduction from the average natural gas CT in EKC's fleet today.

VIII. Reasonableness of the Decision to Build Kansas Sky Solar

A. Overview

Q. Does Staff consider the decision to build Kansas Sky Solar to be reasonable?

A. Yes. Staff considers the decision to acquire Kansas Sky to be reasonable because it is both reliable and efficient to do so as discussed in more detail in the testimony that follows. Also, the fact that near term solar investment has been supported by the IRP since 2021 is a strong indication of the reasonableness of this decision. In addition, Kansas Sky will further diversify Evergy's generation portfolio by adding peak-correlated and fuel-cost-free energy production that is located very close to Evergy load.

1. Consistent IRP Support

Q. Please discuss the Evergy IRP's that have supported the addition of near-term Solar.

A. Evergy's 2021 IRP called for 350 MW of solar by 2023. The 2022 IRP called for 190 MW of solar by 2024, and the 2023 IRP called for 150 MW of solar by 2027. Evergy's 2024 IRP supported the 2027 solar build in every alternative resource portfolio studied, even the scenario AFAD, which was specifically optimized for a future with few carbon constraints, and which did not allow any coal retirements after the conversion of Lawrence 5 to natural gas, and the retirement of Lawrence 4 in 2028. When Evergy forced the IRP model not to choose 150 MW of solar in 2027, the result was an increase in costs of $59 million in NPVRR. This calculation understates the actual benefits of adding Kansas Sky because the anticipated cost of the Solar facility is approximately 30% less than the generic solar resource modeled in the 2024 IRP.[87]

2. Increased Generation Portfolio Diversification

Q. Please explain how Kansas Sky improves the diversification of Evergy's Generation portfolio.

A. The addition of Kansas Sky will improve the diversification of Evergy's generation mix, which will provide a hedge against unexpected natural gas or wholesale energy price shocks like what occurred during 2022 in the runup to the Russian invasion of Ukraine. Because the Solar resource will produce more peak-correlated energy, and because it is located closer to Evergy's load, the SPP IM revenue profile of the facility will be better correlated to Evergy's cost to serve load in the SPP IM compared to most wind generation sites in Evergy's footprint.

IX. Reliability of Kansas Sky Solar

A. Overview

Q. Does Staff view the addition of Kansas Sky Solar to be reliable?

A. Yes. While adding Kansas Sky to Evergy's generation fleet does not support reliability in the same fashion that the addition of dispatchable generation does, it does have reliability benefits that will improve reliability for EKC's customers once

[87] *See* Direct Testimony of Evergy witness Darrin Ives at page 22, line 11.

it is in service. In the testimony below I will address both the Summer and Winter reliability contributions of Kansas Sky Solar.

1. Summer Reliability Contribution of Kansas Sky Solar

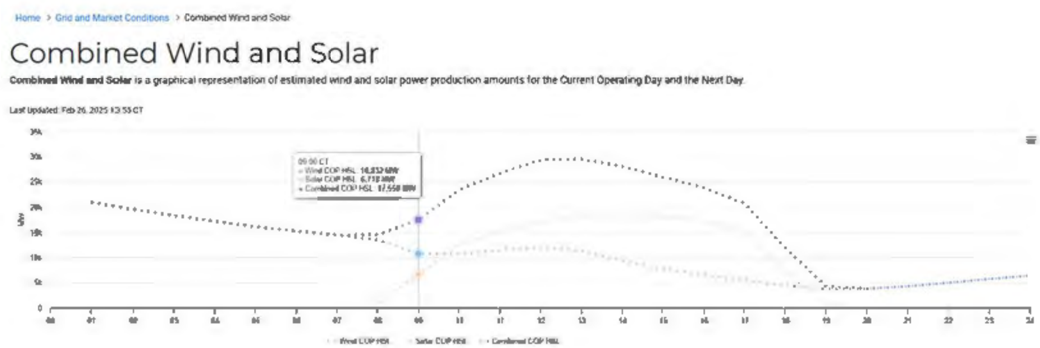
Q. How does the addition of Kansas Sky contribute to reliability in the Summer?

A. There is significant summer reliability value associated with adding solar generation into SPP right now because there is only 986 MW of utility scale solar installed in the entire SPP region as of January 1, 2025. As a result, Kansas Sky is expected to receive a 65 to 70% summer ELCC accreditation percentage when installed, which reflects the likelihood that this asset will be able to serve load during summer peak energy needs of the system.

Utility scale solar is naturally summer peak correlated, and it tends to have an offsetting generation profile compared to that of wind generation assets. Many times, right when wind generation falls off in the morning, solar resources ramp up. Accordingly, the addition of solar to the grid offsets the morning ramp requirements of conventional generation on the system or can offset exposure of load to other higher cost generation sources when the demands on the grid are at their highest. You can see this relationship play out nearly every day by viewing the combined wind and solar output graphs at www.ercot.com.

For example, the screenshot below was taken at 9:00 AM on February 26, 2025. The purple line in the graph is combined wind and solar, the blue line is wind, and the yellow line is solar. As the graph shows, almost at the precise time that wind generation starts to drop off this morning, solar generation comes online.

The result is that the combined wind and solar graph didn't drop off significantly but instead grew for the next several hours.



In recent years the level of solar in ERCOT has grown significantly, to over 20,000 MWs. This solar generation has been widely credited with helping ERCOT meet extreme peak demands that occurred on its system during the summer 2024.[88]

2. Winter Reliability Contribution of Kansas Sky Solar

Q. How does the addition of Kansas Sky contribute to winter reliability?

A. While solar generation does not contribute to the winter capacity needs of EKC in the same fashion as a dispatchable generator can, it can provide reliability benefits during the winter, especially coming from a place of having almost no solar on the system. For example, this can occur on those extremely cold clear mornings, in

[88] *See* Denholm, Paul, Victor Duraes de Faria, and Jason Frost. 2024. How the U.S. Power Grid Kept the Lights on in Summer 2024. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A40-91517. https://www.nrel.gov/docs/fy25osti/91517.pdf.

which the absence of cloud cover allows the surface temperature to cool significantly.

The winter reliability of adding solar to the SPP system was discussed extensively in SPP working groups, including SAWG, CAWG, REAL, RSC and the SPP Board, when SPP set its first financially binding Winter PRM in the Summer of 2024. SPP's LOLE modeling results showed that an increase in utility scale solar from 444 MW (existing at the time) to a projected level of 4,828 MW of solar by the Winter of 2026 would help the region meet mandatory reliability metrics of a loss of load event occurring no more than 1 day in 10 years (or .1 day per year).

More specifically, SPP calculated that the region's Winter PRM could be 33% in the Winter of 2026 *if* there was 4,384 MW more solar online by then. But, because there was considerable uncertainty whether that projected solar could be built fast enough, due to supply chain risks, interconnection delays, and increasing amounts of local opposition to utility scale solar siting, ultimately the RSC and SPP Board ended up approving a 36% Winter PRM for the Winter of 2026/2027.[89] Because the addition of solar would have allowed for a smaller regionwide Winter PRM, this plainly demonstrates the value of utility scale solar to help EKC serve the reliability needs of its customers in the Winter.

[89] *See* Staff Exhibit JTG-11 for excerpts of SPP presentations pertaining to Winter Reliability Value of Solar.

X. Efficiency of Kansas Sky Solar

A. Overview

Q. What factors support the efficiency of adding the Kansas Sky Solar facility to Evergy's generation portfolio?

A. The fact that Evergy's 2024 IRP and the updated capacity expansion modeling contained in this Docket both support the addition of the Kansas Sky solar facility, is strong support for the efficiency of this decision. Additionally, Staff has evaluated the efficiency of the Kansas Sky Solar facility by comparing:

1. the expected LCOE of the Solar facility to the PPA offers received by Evergy in response to its 2023 all-source RFP; and
2. the all-in capital cost estimate for the Kansas Sky facility to other recently announced cost estimates for utility scale solar in the region.

1. LCOE of Kansas Sky vs. PPAs

Q. Please discuss how the Kansas Sky LCOE compares to the PPA offers Evergy received in its 2023 All-Source RFP.

A. The LCOE of the Solar facility, calculated by Evergy to be **[redacted]**, is lower than all PPA offers received by Evergy in its 2023 all source RFP, except for one project that was **[redacted].**[90] The average PPA offer received by Evergy was **[redacted]**, and the average for all projects under 300 MW was **[redacted]**.

[90] *See* Evergy Confidential Response to Staff Data Request No. 35, contained in Exhibit JTG-14.

Q. Has Staff calculated an estimated LCOE for the Kansas Sky Solar facility?

A. Yes. Staff used the same excel spreadsheet used by Evergy to estimate the LCOE of the Kansas Sky solar facility, as adjusted for three items:

1. the removal of future "maintenance" capital expenditures anticipated by Evergy in years 12-16;
2. an update of the estimated capacity factor to **[redacted]** to reflect the most recent estimate provided in the confidential response to KIC Data Request No. 4-1;[91] and
3. the reduction in anticipated construction costs to account for Evergy's updated cost of purchased **[redacted]**.

Accounting for each of the above changes, Staff's estimated LCOE for the Solar project is **[redacted]**.[92]

2. All-in Capital Cost Comparison of Kansas Sky to Other Projects

Q. Has Staff performed a comparison of the estimated all-in capital cost of the Kansas Sky solar facility to other recent utility scale solar projects?

A. Yes. The anticipated all-in capital cost of the Solar facility at **[redacted]** (accounting for Staff's adjustment described below), compares favorably with other recently announced utility scale solar projects. This includes those described on page 20 of Evergy witness John Carlson's Direct Testimony, as well as another

[91] *See* Evergy Confidential Response to KIC Data Request No. 4-1, contained in Exhibit JTG-14.
[92] *See* Staff Exhibit JTG-4.

recently announced 500 MW solar project in Missouri, with an anticipated capital cost of $950 million, or $1,900/kW.[93]

XI. Risks Associated with Kansas Sky Solar

A. Overview

Q. Are there specific risks associated with the completion of this project that Staff is concerned about?

A. Yes. Staff is particularly concerned about the potential risk to the project if there were to be a repeal of the clean energy tax credits that are currently authorized by the IRA.[94] Also, the Kansas Sky Solar project is currently at risk given the ongoing litigation pertaining to the issuance of a Conditional Use Permit (CUP) for the project by Douglas County, Kansas.

1. Repeal of IRA Clean Energy Tax Credits

Q. What is the risk to the Kansas Sky Solar facility if the clean energy tax credits that are a part of the IRA are repealed?

A. The economics of the Kansas Sky Solar facility are significantly impacted by the assumption that the production tax credits (PTC) authorized by the IRA will be available to produce tax benefits for the first 10-years of this project. Using this LCOE model attached to Evergy witness John Carlson's Direct Testimony as confidential Exhibit JC-4, Staff calculated a **[redacted]** increase in the LCOE from

---

[93] *See* https://fox2now.com/news/missouri/ameren-missouri-brings-3-solar-facilities-online/

[94] *See* Republicans to grapple with clean energy tax credit repeal amid budget talks, February 26, 2025, attached as Staff Exhibit JTG-5.

the Solar facility, from **[redacted]** to **[redacted]**, when the PTC was removed from the model.

In response to Staff Data Request No. 22, Evergy stated "any change to the production tax credits or investment tax [credits] under the new administration in Washington is speculative and the Company would need to assess any change to the IRA."

Because the PTC affects the economics of the Kansas Sky solar project so significantly, Staff recommends that the Commission only approve the decision to build the Solar facility with the condition Evergy be required to make a filing to the Commission justifying the continued prudence and economic efficiency of the decision to construct the Solar facility, if the PTC provisions of the IRA are repealed prior to the beginning of construction.

2. Litigation on Douglas County Issuance of CUP

Q. What is the risk to the Kansas Sky Solar facility associated with the pending litigation against Douglas County, Kansas, for the issuance of the CUP?

A. There is a risk to approving the Solar project in that the project is currently involved in litigation pertaining to the issuance of a CUP by Douglas County, Kansas, as discussed on page 6 of the Supplemental Direct Testimony of Jason Humphrey and as described in the Confidential response to Staff Data Request No. 34. Staff is not recommending a condition of approval pertaining to this outstanding CUP issue, because Evergy's Purchase and Sale agreement with the developer of the Solar facility already contains an explicit condition precedent that requires this issue to be resolved before Evergy will close on the project.

XII. Definitive Cost Estimates and Ratemaking Treatment

A. Overview

Q. Has Staff evaluated the reasonableness of the requested DCEs and Ratemaking Treatment for the CCGTs and the Solar project?

A. Yes. In the testimony below, I will address separately Staff's review of the requested DCEs and ratemaking treatment for both of the CCGTs and the Solar project.

1. DCE for Viola CCGT

Q. What is Staff's recommendation regarding the DCE for the Viola CCGT?

A. Staff recommends that the Commission approve as reasonable Evergy's requested DCE for the Viola CCGT of [redacted]** (excluding AFUDC), (**[redacted]** for a 50% share), as depicted on Evergy witness Kyle Olson's Confidential Exhibit JKO-10.

Mr. Olson's Supplemental Direct Testimony describes this estimate as an AACE[95] Class-2 estimate, which according to the AACE, should indicate accuracy to the range of -15% below to 20% above the actual cost of the project.

[95] AACE stands for the Association for the Advancement of Cost Engineering.

2. DCE for McNew CCGT

Q. What is Staff's recommendation regarding the DCE for the McNew CCGT?

A. For the McNew CCGT, Staff recommends the Commission approve a revised DCE of **[redacted]** (excluding AFUDC), (**[redacted]** for a 50% share). This reflects a reduction of **[redacted]** from Evergy's requested DCE, as listed in Confidential Exhibit JKO-11. Staff contends that this revised DCE better reflects the projected costs of the PIE Equipment for the McNew CCGT. As discussed in confidential response to Staff Data Request No. 51, Evergy rounded down the **[redacted]** estimate for the Viola CCGT to **[redacted]** but rounded up an estimated **[redacted]** amount for the McNew CCGT to **[redacted]**. Staff contends that similar to the **[redacted]** estimate, the PIE estimate for the McNew CCGT should be rounded down to the nearest million.

Q. Do the DCEs for the Viola and McNew CCGT contain any estimated contingency funds?

A. Yes, in response to Staff Data Request No. 19, Evergy confirmed that the DCE for the CCGTs contains a contingency amount of **[redacted]** of the project's estimated total cost, based upon "the uncertainty in the current market." In the confidential response to Staff Data Request No. 49, Evergy provided additional support for the reasonableness of the contingency amount, as follows:

> **[redacted].

[redacted]

[redacted].**

Staff recognizes that the contingency amounts included in the DCEs for the CCGTs appears significant, but there are still some significant uncertainties outstanding regarding the final cost of these facilities. For example, while Evergy has done an admirable job estimating the potential cost of Transmission Network Upgrades that may result from building these facilities, there is uncertainty about the magnitude and cost of these upgrades until the interconnection studies are completed by SPP.[96] Also, as addressed in the Supplemental Direct Testimony of Jason Humphrey, there is considerable uncertainty right now in the United States regarding what level of tariffs will ultimately be levied on metal products and other imports that will be used to construct the CCGTs. For these reasons, and considering the explanation included in Evergy's response to Staff Data Request No. 49 above, Staff considers the contingency amounts in the DCEs to be reasonable.

[96] *See generally* Direct Testimony of Evergy witness Katy Onnen.

Q. On page 9 of Mr. Humphrey's Supplemental Direct Testimony, he recommends that Evergy be granted leave to submit an adjusted DCE, with supporting testimony, accounting for any known and quantifiable tariff-related impacts. How would you respond to this request?

A. Staff does not support this request at this time. It is unclear how such an update would be possible within the current procedural schedule, given the Commission's statutory deadline to issue an Order in this case by July 7, 2025. Additionally, as discussed above and in response to Staff Data Request No. 49, one of the explanations for the current contingency amounts included in the DCE is the potential for **[redacted].''** If Evergy wants to revise its DCE, Staff would recommend the Commission:

1. Require Evergy to rerun its capacity expansion modeling to ensure that the CCGT was still part of an optimized portfolio selection; and
2. Provide Staff and Intervenors adequate time to respond to the revised DCE and capacity expansion modeling, with Supplemental Direct Testimony.

3. DCE for Kansas Sky Solar

Q. What is Staff's recommendation regarding the DCE for the Kansas Sky Solar facility?

A. Staff recommends that the Commission approve a revised DCE for the Kansas Sky Solar project of **[redacted]** (excluding AFUDC), a reduction of **[redacted]

[redacted]** from Evergy's requested DCE of **[redacted].**[97] This adjustment reflects the lower agreed upon purchase price of **[redacted]**, as described in Exhibit JOH-2 attached to the Supplemental Direct Testimony of Jason Humphrey, and as referenced in response to Staff Data Request No. 20.

4. **Ratemaking Treatment for Kansas Sky Solar**

Q. What is Staff's recommendation regarding the requested ratemaking treatment for the Kansas Sky Solar facility?

A. Staff recommends approval of the levelized revenue requirement approach described in Evergy witness John Grace's Direct Testimony. This approach has been approved previously by the Commission for the recovery of both the Western Plains Wind Farm, and the Persimmon Creek Wind Farm, in Docket Nos. 18-WSEE-328-RTS, and 23-EKCE-775-RTS, respectively. Staff supports the use of this ratemaking mechanism to avoid the dramatic fluctuation (and arguable intergenerational inequity) that would otherwise occur in the revenue requirement because of the significant PTC value that occurs for Kansas Sky during the first 10-years. The levelized revenue requirement approach also acts as a performance based ratemaking mechanism because the revenue requirement is fixed for the life of the plant, absent extraordinary circumstances that would be outside of the control of Evergy, and for which there would be a material adverse impact on the utility.

Staff recommends that the Commission require Evergy to update the Kansas Sky Solar levelized cost amount in the first rate case after the facility goes into

[97] Staff Exhibit JTG-12, which contains the Kansas Sky solar cost estimation spreadsheet, as adjusted to include the updated cost of **[redacted].**

service, to account for actual construction costs once they are known, subject to Staff's recommended DCE of **[redacted]**, or a prudency evaluation for costs incurred in excess of the DCE.

Staff's current estimate of the levelized revenue requirement for the Kansas Sky facility is **[redacted]** per year, which is a reduction from the **[redacted]** calculated in Evergy's filing. The difference in these levelized cost estimates pertains to Staff's recommendation to remove future "maintenance" capital expenditures estimated by Evergy to occur in years 12-16, an update to the anticipated capacity factor of the Solar unit, and an update to reflect the updated cost of the **[redacted]** secured by Evergy.[98]

Q. Why did Staff removal maintenance capital expenditures from the estimated LCOE and revenue requirement for the Kansas Sky Solar facility?

A. Staff removed these future capital expenditures from the levelized revenue requirement because it is inappropriate to reflect the revenue requirement associated with them prior to the capital actually being spent. To do so would be akin to providing Evergy investors a return 'on and of' capital investments upfront, when the actual capital expenditures won't be made for more than a decade into the future. Staff considers that to be inequitable, unjust, and unreasonable. Instead, I recommend that these capital expenditures be treated as part of the normal rate case process in the future when they are made. Evergy should be required to explicitly

[98] *See* Staff Exhibit JTG-4.

identify and support these capital expenditures in a future rate case, so that they can be reviewed at that time.

Q. What does Evergy request pertaining to Construction Accounting Treatment for Kansas Sky Solar?

A. Evergy witness Darrin Ives addresses the request for Construction Accounting Treatment for Kansas Sky Solar on page 21 of his Direct Testimony. The request is for EKC to be permitted to defer and recover as a regulatory asset the pretax rate of return, depreciation expense, and actual O&M expenses, offset by the value of the PTCs generated, between the time that the Solar facility is placed in service and the effective date of the first rate case that includes the levelized cost of the Solar facility. This regulatory asset would then be amortized over the life of the Solar facility.

Q. What is Staff's recommendation pertaining to the request for Construction Accounting Treatment?

A. Staff recommends approval of this request. Construction Accounting Treatment is an equitable way to capture the revenue requirement changes that occur with the addition of a new generation facility into service. Through this predetermination Docket we have determined that Kansas Sky solar is reasonable, reliable and efficient. It is a needed facility that will benefit ratepayers in Evergy's service territory. Accordingly, it is reasonable to capture the net revenue requirement increase associated with this asset, after it is placed in service to benefit customers, but prior to being included in customer rates, to allow those costs to be amortized over the life of the Solar facility. The Commission has previously approved Construction Accounting Treatment for the environmental retrofits of the LaCygne and Iatan coal-fired generation units.[99] Additionally, Construction Accounting Treatment is required for the CCGTs by K.S.A. 66-1239.

5. Significance of the DCEs for Prudency Evaluation

Q. What is the significance of the DCEs for any future prudence review of the final cost of the CCGTs and the Kansas Sky Solar facility?

A. In the 11-581 Docket the Commission previously held the following regarding the use of DCEs for future prudency evaluation:

> Here, KCP&L has presented an Original Cost Estimate that will be treated as a definitive estimate under K.S.A. 66-128g(b)(l). If KCP&L completes construction of the La Cygne Project within this definitive estimate, absent a showing of fraud or other intentional imprudence in the construction project, the Commission will find this amount was prudently incurred and will not address prudency issues regarding the reasonable value of the La Cygne Plan retrofits under K.S.A. 66-128g. However, if costs exceed the definitive estimate of $1.23 billion, excluding AFUDC and property taxes, and KCP&L seeks to recover this excess from ratepayers in a subsequent proceeding, then KCP&L will bear the burden to show that any amount over the definitive estimate of $1.23 billion, excluding AFUDC and property taxes, was prudently incurred.[100]

Staff recommends that the Commission find in this proceeding, like it did in the 11-581 Docket, that Evergy will bear the burden of proof regarding the reasonableness

[99] *See* Order Approving Joint Application, ¶ 13, Docket No. 15-GIME-025-MIS (September 9, 2014); and Order: 1) Approving Stipulation and Agreement; and 2) Addressing Scope of Final Rate Case Under the Approved 2005 Regulatory Plan, Docket No. 09-KCPE-246-RTS (Jul. 24, 2009).

[100] *See* Order Granting KCP&L Petition for Predetermination of Ratemaking Principles and Treatment, ¶ 75, 11-581 Docket (Aug. 19, 2011).

and prudence of any cost overruns of the CCGTs or the Kansas Sky Solar facility in excess of the DCEs approved in this Docket.

6. Significance of the DCEs for CCGT Semi-Annual Surcharge

Q. What is the significance of the DCEs for the semi-annual surcharge that will be billed to customers to recover Construction Work in Progress (CWIP) amounts from the CCGTs?

A. K.S.A. 66-1239 limits the total CWIP amounts that can be included in the revenue requirement calculation of the semi-annual surcharge for the CCGTs. The total CWIP amount included in these calculations cannot exceed the DCE found reasonable by the Commission, unless the Commission otherwise orders in a subsequent proceeding.

XIII. Conclusions and Recommendations

A. Conclusions

Q. Please provide a recap of the conclusions you have reached as a result of your review of the predetermination request currently before the Commission?

A. As a result of my review in this Docket, I have reached the following conclusions:

- Evergy's plan to acquire a 50% portion of the Viola plant, a 50% portion of the McNew plant, and 100% of the Kansas Sky solar facility, is consistent with Evergy's most recent preferred plan and resource acquisition strategy, as filed with the Commission in Evergy's 2024 IRP filing, and as updated through the modeling and analysis presented by Evergy in this Docket.

- Evergy has solicited several RFPs from a wide audience of participants willing and able to meet the needs identified under its preferred plan.
- Evergy's resource plan, consisting of the 50% ownership of each CCGT and the 100% ownership of the Solar facility, is reasonable, reliable and efficient, subject to the conditions and compliance issues discussed in detail in this testimony. Accordingly, Staff recommends that the Commission find it is prudent for Evergy to acquire these resources, up to the definitive cost estimates Staff recommends for each asset.
- The decision to build the CCGT facilities is reasonable in part because they are both reliable and efficient. Additionally, the decision to build the CCGTs is reasonable because:
  - It is reasonable to plan in advance to for the eventual retirement of Evergy's coal fleet, even if the specific date that any individual coal unit will retire is uncertain at this time.
  - Evergy currently anticipates load growth of 2-3% annually through 2029 and has a robust economic development pipeline that would more than double its current peak demand if it all materialized. SPP too is experiencing rapid load growth and declining reserve margins;
  - It will allow Evergy the ability to reliably serve native load and respond to increased load growth in Evergy's service territory, with dispatchable, highly efficient generation;
  - It positions Evergy well for a highly uncertain future, even if that future is dominated by intermittent, weather dependent sources of

energy such as wind and solar, or more significant restrictions on the production of carbon dioxide as a byproduct of electricity generation;

  - It helps Evergy respond to increasingly tighter RA standards being enacted by the SPP;
  - It allows EKC to further increase the diversity of its electric generation fuel sources, and
  - It is responsive to the Energy Policy signals provided by the Kansas Legislature and the Governor, as expressed through the passage of House Bill 2527.

- The decision to build the CCGTs is reliable because:
  - The CCGTs will add highly flexible, dispatchable generation to the system, which offers critical reliability services for customers, like the ability to ramp up quickly when needed.
  - These CCGTs are being built to withstand winter temperatures as low as -15 Fahrenheit and they will be served by firm natural gas transportation contracts.
  - Recent weather events have proven that there have been significant improvements since Winter Storm Uri in the ability of the natural gas and electric industries to maintain reliability during extreme winter weather events.
  - The CCGTs are expected to have very low forced outage rates.

- In Section 18 of Evergy's 2024 IRP analysis, it evaluated the reliability of the preferred resource plan using the SERVM software. These results showed that Evergy's preferred resource plan would exceed the industry standard LOLE metric of .1 (one day in ten years, or .1 day per year).

- The decision to build the CCGTs is efficient because:
    - These CCGTs are highly fuel efficient, approximately 40% more efficient than the average natural gas unit in Evergy's fleet in terms of the ability to generate one MWh of electricity per MMBtu.
    - The CCGTs were selected as part of the updated 2024 IRP analysis that Evergy conducted in support of this Application which selects the least cost portfolio of resources, given a certain set of constraints, assumptions, and scenarios.
    - The competitive process that Evergy has utilized to construct and select these projects will ensure that they are efficiently priced. Additionally, Evergy plans to economically commit the CCGTs in the SPP IM.
    - Staff evaluated the efficiency of the Viola and McNew CCGTs using the S&P Global Power Evaluator software platform. For Viola the result was an anticipated 77.19% capacity factor in year 1, and an estimated LCOE of $68/MWh. For McNew the result was an anticipated 72.61% capacity factor in the first year, with a LCOE estimated at $74/MWh.

  - The estimated LCOE figures calculated by the Power Evaluator software compare favorably to the average LCOE of $76/MWh reported for a new CCGT by the Lazard 2024 LCOE report, which also provided a range of LCOEs for new CCGTs, estimated to be $45 to $108/MWh.
  - The CCGTs will be very efficient from a carbon dioxide emissions perspective, allowing a 61% reduction from the average coal-fired generation unit in EKC's fleet today and a 53% reduction from the average natural gas CT in EKC's fleet today.
- The decision to build the Kansas Sky solar facility is reasonable in part because it is both reliable and efficient. Additionally, the decision to build the Solar facility is reasonable because:
  - Evergy's IRP has supported the addition of near-term solar since 2021 and Evergy's 2024 IRP supported the 2027 solar build in every scenario studied. Removing the Solar facility from the IRP portfolio resulted in an increase in costs of $59 million in NPVRR.
  - The addition of this solar farm, will improve the diversification of Evergy's generation mix, and provide a hedge against higher natural gas and wholesale market prices.
- The decision to build the Solar facility is reliable because:
  - There is very little utility scale solar in SPP today, just 986 MW as of January 1, 2025. Accordingly, the reliability value of adding additional solar into SPP right now is very high, and it is anticipated

that these assets will receive high summer ELCC accreditation percentages (65-70%) when they are installed.

- Utility scale solar is naturally summer peak correlated and it tends to have an offsetting generation profile to that of wind generation assets. Accordingly, the addition of solar to the grid can cut down on the ramping requirements of conventional generators on the system, when wind suddenly dries up on the hottest days of the summer.
- The addition of Kansas Sky solar will provide reliability benefits during the winter, especially coming from a place of having almost no solar on the system. This is especially true on extremely cold mornings, in which the absence of cloud cover allows the surface temperatures to cool significantly.

• The decision to build the Solar facility is efficient because:
  - The LCOE of the Solar facility, calculated by Evergy to be **[redacted]**, is lower than all PPA offers received by Evergy in its 2023 all source RFP, except for one project that was **[redacted]**.
  - When adjusted by Staff to remove future "maintenance" capital expenditures anticipated by Evergy in years 12-16; to update the capacity factor to **[redacted]** to reflect the most recent estimate; and to reflect the reduction in anticipated construction costs to account

for the updated lower cost of purchased **[redacted]**, Staff's calculated LCOE for the Solar project is **[redacted]**.

  - The anticipated all-in capital cost of the Solar facility at **[redacted]** (accounting for Staff's adjustments), compares very favorably with other recently announced utility scale solar projects.

- There are risks associated with the decision to acquire Kansas Sky Solar that should be closely monitored and continue to be evaluated, including:
  - There is a significant amount of uncertainty right now in the fate of the clean energy tax credits that are authorized by the IRA. The economics of the Kansas Sky Solar are greatly affected by the existence of the PTC to produce tax benefits for the first ten years of the project life.
  - There is a risk to approving the Solar project in that the project is currently involved in litigation pertaining to the issuance of a CUP by Douglas County, Kansas. Evergy's Purchase and Sale agreement with the developer of the Solar facility contains an explicit condition precedent that requires this issue to be resolved before Evergy will close on the project.

B. Recommendations

Q. Please provide a list of the specific recommendations you are making to the Commission?

A. Staff recommends the following:

- The Commission should approve Evergy's decision to acquire 50% of the Viola CCGT, 50% of the McNew CCGT, and the Kansas Sky Solar facility, as reasonable, reliable, efficient, and consistent with Evergy's most recent preferred plan and resource acquisition strategy.
- The Commission should approve as reasonable Evergy's requested DCE for the Viola CCGT of **[redacted]** (excluding AFUDC) for a 50% share, as depicted on Evergy witness Kyle Olson's Confidential Exhibit JKO-10.
- The Commission should approve as reasonable a revised DCE of **[redacted]** (excluding AFUDC) for a 50% share of the McNew CCGT. This reflects a reduction of **[redacted]** from Evergy's requested DCE, as listed in Confidential Exhibit JKO-11.
- Evergy should bear the burden of proof to show that any amount it incurs in excess of these DCEs is prudently incurred and is reasonable to recover from ratepayers, consistent with the Commission's previous findings in the 11-581 Docket.
- The Commission should approve a revised DCE for the Kansas Sky Solar project of **[redacted]** (excluding AFUDC), a reduction of **[redacted]** from Evergy's requested DCE of **[redacted].**

- The Commission should approve the Construction Accounting treatment described in the Direct Testimony of Darrin Ives at page 21 pertaining to construction accounting and the use of deferred regulatory accounting to capture the net revenue requirement impacts of the Solar facility prior to the facility being reflected in rates.
- The Commission should require Evergy to update the Kansas Sky Solar levelized cost amount in the first rate case after the facility goes into service, to account for actual construction costs once they are known, subject to the revised DCE of **[redacted]**, or a prudency evaluation for costs incurred in excess of the DCE.
- The Commission should not allow the recovery of any maintenance capital expenditures as part of the levelized revenue requirement of Kansas Sky and instead should require Evergy to identify and support these investments in a future rate case.
- Evergy should be required to collaborate with Staff and CURB during the development of a Gas Purchasing Plan, and to file the results of the plan in a compliance filing at the KCC. Thereafter, Evergy should be required to meet at least annually with Staff and CURB to discuss potential revisions to the Gas Purchasing Plan. Additionally, should the addition of the CCGTs materially revise Evergy's current Natural Gas Hedging Plan, Evergy should be required to collaborate with Staff and CURB on the particulars of a revised Hedging Plan to be filed at the Commission.

- Evergy should file a compliance filing with the KCC once all natural gas transportation arrangements have been finalized. This filing should include, at a minimum, the financial terms and conditions under which firm natural gas transportation has been secured and the length of the transportation arrangement.
- Evergy should be required to make a compliance filing with the Commission justifying the economics and prudency of continuing forward with the Kansas Sky Solar facility, or informing the Commission that it will abandon the project, if the PTC provisions of the IRA are substantially revised or repealed prior to the start of construction on the Kansas Sky Solar facility.

Q. Does this conclude your testimony?

A. Yes, thank you.

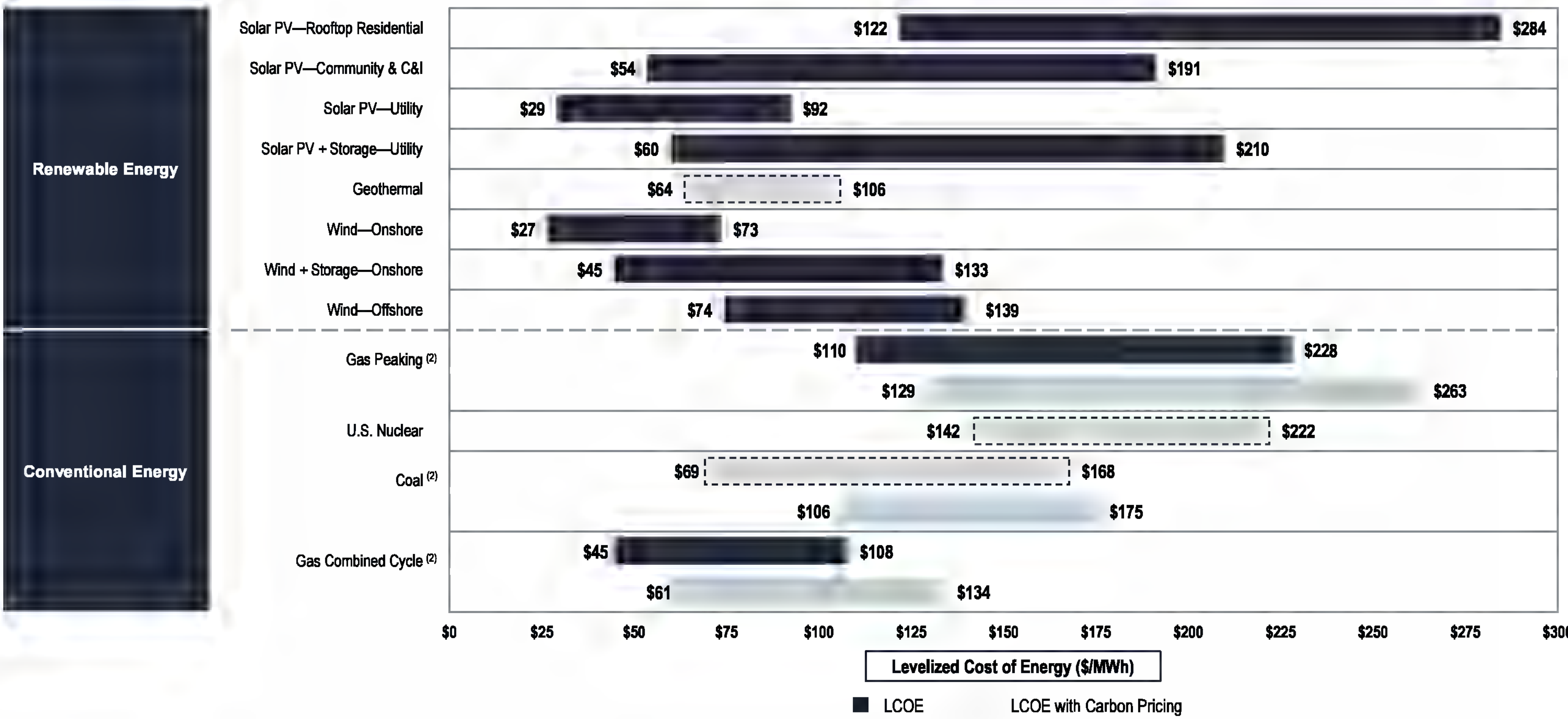
STAFF EXHIBIT JTG-1

Option 3A – On-site Liquid Fuels

Category	On site Liquid Fuel Storage	Season	Unit Capability Range	Number of Units	Capacity Claimed	Weighted EFORd	Weighted EFOF
Conventional Hydroelectric	N/A	Summer	10.8 - 102	58	2,812	0.4%	N/A
		Winter	10.8 - 102	58	2,842	0.5%	0.1%
Hydroelectric Pumped Storage	N/A	Summer	48 - 48	6	258	7.7%	N/A
		Winter	48 - 48	6	258	7.3%	19.1%
Combined Cycle (Natural and other gas)	Yes and No	Summer	19.8 - 390	81	12,103	6.9%	N/A
		Winter	19.8 - 390	75	11,083	6.8%	8.5%
Combustion Turbine (Fuel Oil, Natural Gas, Kerosene)	No	Summer	3.5 - 203	106	7,286	8.4%	N/A
		Winter	3.5 - 203	106	7,407	20.9%	19.7%
	Yes	Summer	15.1 - 178.5	83	3,784	13.0%	N/A
		Winter	15.1 - 178.5	83	3,970	16.6%	8.7%
Reciprocating Internal Combustion Engine	No	Summer	0.5 - 22.10	104	741	7.4%	N/A
		Winter	0.5 - 22.10	104	731	11.2%	9.4%
	Yes	Summer	0.10 - 9.3	438	906	7.6%	N/A
		Winter	0.10 - 9.3	431	898	9.9%	9.4%
Steam Turbine (Coal)	Yes and No	Summer	16.5 - 922.5	63	22,753	9.2%	N/A
		Winter	16.5 - 922.5	62	22,542	11.0%	11.1%
Steam Turbine (Natural gas and other)	Yes and No	Summer	12.5 - 572.3	57	9,673	14.0%	N/A
		Winter	12.5 - 572.3	57	9,441	13.3%	11.4%
Steam Turbine (Nuclear)	N/A	Summer	801 - 1267	2	1,945	1.1%	N/A
		Winter	801 - 1267	2	1,987	1.9%	1.3%

Levelized Cost of Energy Comparison—Sensitivity to Carbon Pricing

Carbon pricing is one avenue for policymakers to address carbon emissions; a carbon price range of $40 – $60/Ton[1] of carbon would increase the LCOE for certain conventional generation technologies, as indicated below

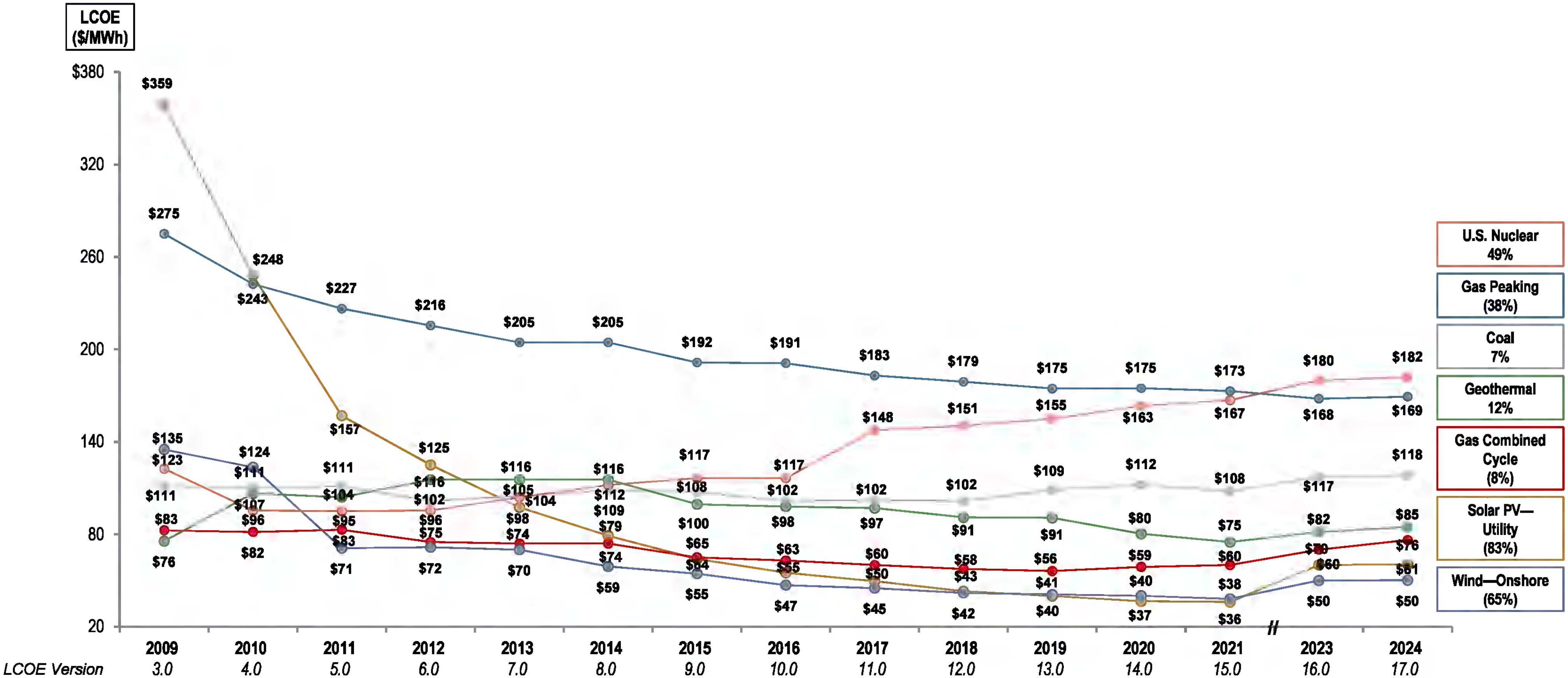


Source: Lazard and Roland Berger estimates and publicly available information.
Note: Unless otherwise noted, the assumptions used in this sensitivity correspond to those used in the LCOE analysis as presented on the page titled "Levelized Cost of Energy Comparison—Version 17.0".
(1) In November 2023, the U.S. Environmental Protection Agency proposed a $204/Ton social cost of carbon.
(2) The low and high ranges reflect the LCOE of selected conventional generation technologies including an illustrative carbon price of $40/Ton and $60/Ton, respectively.

Levelized Cost of Energy Comparison—Historical LCOE Comparison

Lazard's LCOE analysis indicates significant historical cost declines for utility-scale renewable energy generation technologies, which has begun to level out in recent years and slightly increased this year

Selected Historical Average LCOE Values[1]



Source: *Lazard and Roland Berger estimates and publicly available information.*

(1) Reflects the average of the high and low LCOE for each respective technology in each respective year. Percentages represent the total decrease in the average LCOE since Lazard's LCOE v3.0.

STAFF EXHIBIT JTG-3

How the U.S. Power Grid Kept the Lights on in Summer 2024

Paul Denholm,[1] Victor Duraes de Faria,[1] and Jason Frost[2]

1 National Renewable Energy Laboratory
2 U.S. Department of Energy

NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency & Renewable Energy
Operated by the Alliance for Sustainable Energy, LLC

This report is available at no cost from the National Renewable Energy Laboratory (NREL) at www.nrel.gov/publications.

Contract No. DE-AC36-08GO28308

Technical Report
NREL/TP-6A40-91517
November 2024

How the U.S. Power Grid Kept the Lights on in Summer 2024

Paul Denholm,[1] Victor Duraes de Faria,[1] and Jason Frost[2]

1 National Renewable Energy Laboratory
2 U.S. Department of Energy

Suggested Citation
Denholm, Paul, Victor Duraes de Faria, and Jason Frost. 2024. *How the U.S. Power Grid Kept the Lights on in Summer 2024*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A40-91517. https://www.nrel.gov/docs/fy25osti/91517.pdf.

NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency & Renewable Energy
Operated by the Alliance for Sustainable Energy, LLC

This report is available at no cost from the National Renewable Energy Laboratory (NREL) at www.nrel.gov/publications.

Contract No. DE-AC36-08GO28308

Technical Report
NREL/TP-6A40-91517
November 2024

National Renewable Energy Laboratory
15013 Denver West Parkway
Golden, CO 80401
303-275-3000 • www.nrel.gov

NOTICE

This work was authored in part by the National Renewable Energy Laboratory, operated by Alliance for Sustainable Energy, LLC, for the U.S. Department of Energy (DOE) under Contract No. DE-AC36-08GO28308. Funding provided by the U.S. Department of Energy Office of Policy. The views expressed herein do not necessarily represent the views of the DOE or the U.S. Government.

This report is available at no cost from the National Renewable Energy Laboratory (NREL) at www.nrel.gov/publications.

U.S. Department of Energy (DOE) reports produced after 1991 and a growing number of pre-1991 documents are available free via www.OSTI.gov.

Cover Photos by Dennis Schroeder: (clockwise, left to right) NREL 51934, NREL 45897, NREL 42160, NREL 45891, NREL 48097, NREL 46526.

NREL prints on paper that contains recycled content.

Acknowledgments

The authors are grateful to Billy Roberts, National Renewable Energy Laboratory (NREL), for map design and to Emily Horvath and Madeline Geocaris (NREL) for editing. Thanks also to U.S. Department of Energy reviewers Sohum Pawar, J.P. Carvallo, Ryan Wiser, Bahram Barazesh, Colin Cunliff, Mara Winn, Glenda Oskar, Michele Boyd, and Jennifer Downing as well as NREL reviewers Mark Ruth and Gian Porro.

List of Acronyms

BTM	behind-the-meter
CAISO	California Independent System Operator
DOE	U.S. Department of Energy
EIA	Energy Information Administration
ERCOT	Electric Reliability Council of Texas
GW	gigawatt
ISO	independent system operator
ISO-NE	ISO New England
MISO	Midcontinent Independent System Operator
MW	megawatt
NERC	North American Electric Reliability Corporation
NG	natural gas
NPCC	Northeast Power Coordinating Council
PV	photovoltaics
SERC	Southeast Regional Council
SPP	Southwest Power Pool
SRA	Summer Reliability Assessment
WECC	Western Electricity Coordinating Council

Table of Contents

List of Figures

1 Introduction

Maintaining the reliability of the bulk power system, which supplies and transmits electricity, is a critical priority of electric grid planners, operators, and regulators. The demand for electricity is increasing to power data centers, electrification of transportation and other end uses, and more[1]—all while the generation mix is rapidly evolving and fossil fuel plants are being retired. In many regions of the country, the demand for electricity often reaches its highest (peak) levels during summer afternoons when high temperatures drive increased use of air conditioning. Increasing frequency of extreme heat events are also adding to the challenge of serving summer peak demand. In addition, an evolving generation mix with increasing renewables and storage and retirements of older fossil-fueled generators are changing how grid operators maintain reliable electricity supply through these events.[2]

The North American Electric Reliability Corporation (NERC)[3] issues annual assessments and forecasts for the upcoming winter and summer seasons; these risk assessments estimate expected demand levels and the availability of electricity generation to meet that demand during periods identified as having the highest risk of electricity supply shortfall. In its 2024 Summer Reliability Assessment (SRA), NERC identified five regions—illustrated in Figure 1—as having an elevated risk of an outage in "above-normal" conditions.[4] This means these regions faced risks of energy shortfalls under some combination of electricity demand at the highest end of projected ranges and historically high generation outages. The rest of the United States[5] was expected to have "normal" levels of risk.

[1] NERC Long-Term Reliability Assessment https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf

[2] This report focuses on the summer of 2024, but winter peaks can be higher in some regions and of growing concern in many other regions.

[3] NERC is an "international regulatory authority whose mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid." https://www.nerc.com/AboutNERC/Pages/default.aspx

[4] NERC 2024 Summer Reliability Assessment https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2024.pdf

[5] NERC's assessment does not consider Alaska or Hawaii, so this document only considers the conterminous (lower 48) states.

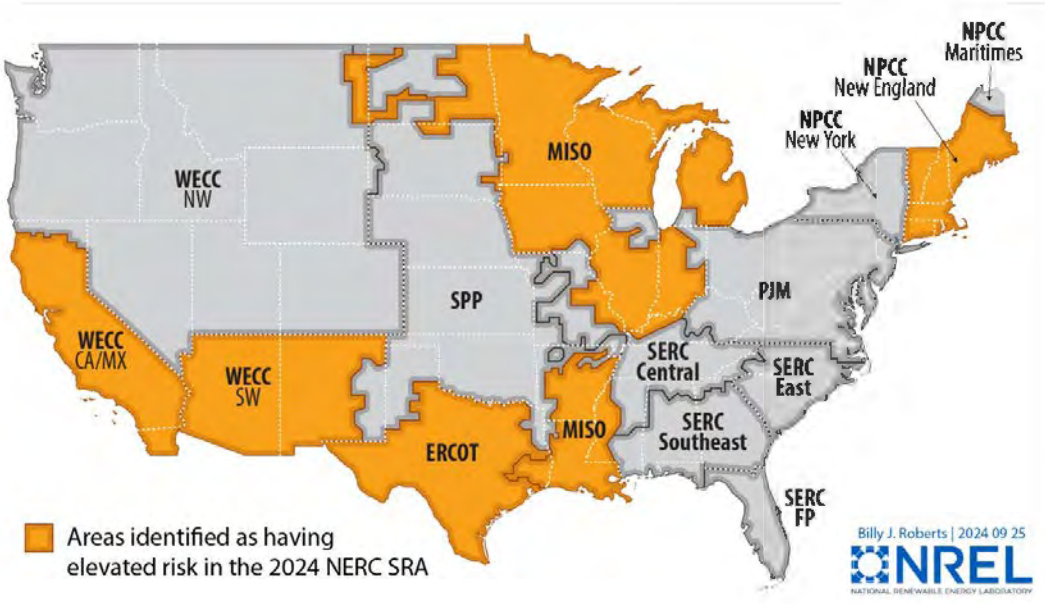


Figure 1. NERC risk assessment regions in the United States, highlighting five regions considered as having elevated risk in summer 2024

WECC = Western Electricity Coordinating Council; SPP = Southwest Power Pool; ERCOT = Electric Reliability Council of Texas; MISO = Midcontinent Independent System Operator; SERC = Southeast Regional Council; NPCC = Northeast Power Coordinating Council

Now that the 2024 summer season has ended and the data have been gathered, we can evaluate grid performance in these "elevated risk" areas of the country. Summertime temperatures in 2024 were above average,[6] driving high electricity demand. Several regions such as the Texas power grid came close to or hit record-high demand for electricity.[7]

Despite the high demand for electricity, there were no major outages caused by inadequate generation capacity. Although some consumers lost power because of localized events, the bulk power system—the network of generators and transmission lines—was able to supply sufficient electricity to keep the lights and air conditioners working.[8]

---

[6] The period of June–August was 2.5°F above average. NOAA "U.S. Climate Summary for August 2024." https://www.climate.gov/news-features/understanding-climate/us-climate-summary-august-2024

[7] ERCOT. October 10, 2024. "Board of Directors Meeting Item 7: Summer 2024 Operational and Market Review." https://www.ercot.com/files/docs/2024/10/03/7-summer-2024-operational-and-market-review.pdf.

[8] This discussion focuses on the bulk power system which consists of generators and the high-voltage transmission network. During summer 2024, there were no significant outages because of failures or insufficient capacity on the bulk power system. Local outages that occurred (and most outages in general) were because of failures on the distribution system, which is the set of lower-voltage wires and systems that deliver electricity from the bulk power system to homes and businesses. NREL "Explained: Reliability of the Current Power Grid" https://www.nrel.gov/docs/fy24osti/87297.pdf

This report briefly describes how various regions in the U.S. power grid kept the lights on in summer 2024. It also highlights notable trends in the evolving grid mix that are helping maintain summer peak reliability in places such as Texas—and how these trends could help maintain future summer reliability in regions throughout the United States.

2 How Did They Do It?

Grid operators used a mix of resources to keep the lights on this summer. Notably, along with existing thermal (fossil and nuclear) and hydropower generation resources, increasing solar and storage resources contributed significantly during peak demand periods in some regions. This report places special attention on Electric Reliability Council of Texas (ERCOT) because it is one of the fastest-growing regions in the country,[9] it experienced near-record peak demand in the summer of 2024, and it shows how rapidly increasing solar and storage deployments can impact summer peak operations. We also examine several other regions that NERC identified as having elevated risk and that vary in deployment of solar and storage resources.

2.1 ERCOT

Figure 2 shows the maximum daily electricity load[10] in ERCOT (black line) from June 1 through September 12, along with the maximum daily population-weighted average temperature[11] (blue line) over the same period. Prior to August 1, the demand peaks were generally below 80,000 megawatts (MW). However, an extended period of hot weather began in early August, with a maximum peak demand on August 20.

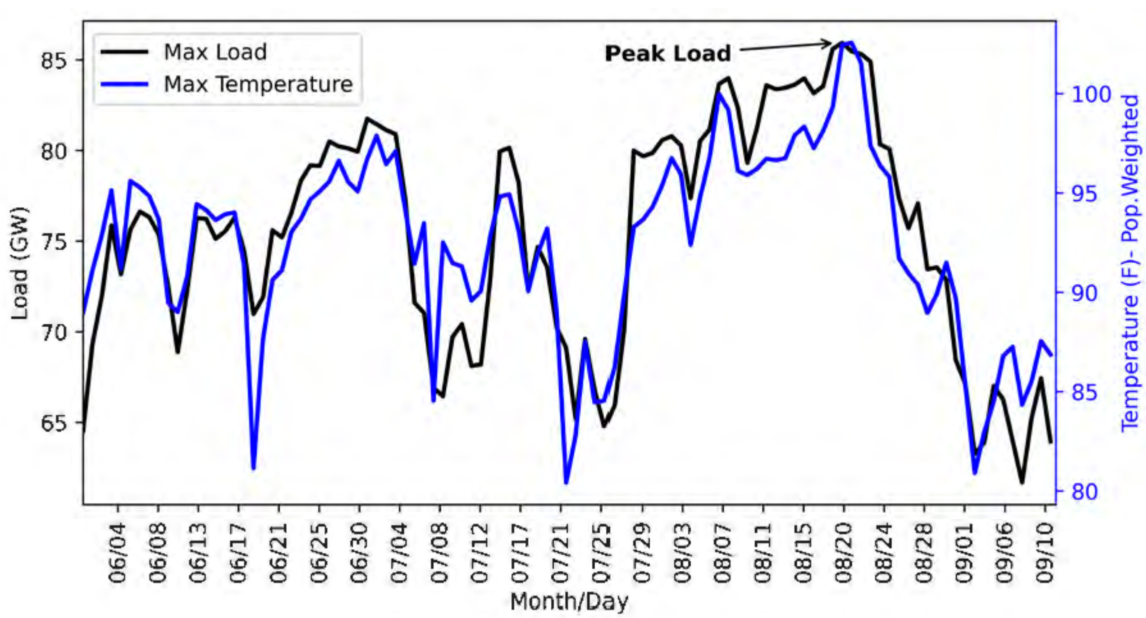


Figure 2. Maximum daily electricity demand (black) in ERCOT in summer 2024 was highest when peak temperatures (blue) averaged over 100°F in August

GW = gigawatts

---

[9] According to NERC's 2023 Electricity Supply and Demand report, ERCOT is projecting demand to grow 15% between 2022 (the last historical year included in the data) and 2026. This is faster than any other region, though load forecasts have continued to change since these data were released in December 2023.
[10] ERCOT load data from https://www.ercot.com/gridinfo/generation.
[11] We estimated the population-weighted average temperature across ERCOT using ZIP code level population from https://statics.teams.cdn.office.net/evergreen-assets/safelinks/1/atp-safelinks.html and temperature data from https://www.ncei.noaa.gov/pub/data/uscrn/products/subhourly01/.

Figure 3 zooms into August 20, the day with the peak demand. The average temperature across ERCOT hit about 102°F, with many regions experiencing higher temperatures. During the peak hour (4–5 p.m.), the average demand was 85,491 MW, with an instantaneous 5-minute peak of 85,931 MW. ERCOT was able to serve this load without generation-related shortfalls.[12]

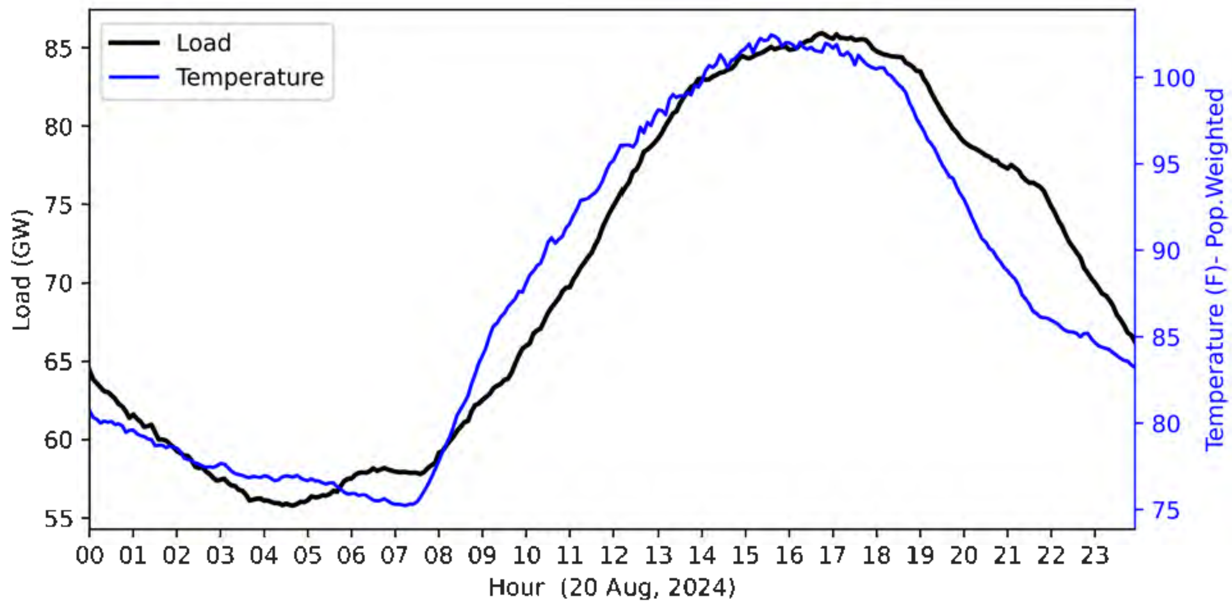


Figure 3. Demand profile and average temperature on August 20, 2024, showing near-record peak demand of more than 85 GW

Figure 4 illustrates the electricity generation by resource type that reliably met the electricity demand on August 20 in ERCOT.[13] Over this 24-hour period, about 66% of total generation was provided by fossil-fueled power plants, and these plants provided about 65% of generation during the peak hour. The remaining contribution was from low-carbon resources (renewables and nuclear). Utility-scale solar provided about 12% of the day's generation.[14] This solar generation had four impacts on the system's ability to serve demand, as illustrated in the figure and described next.

---

[12] As noted previously, there were local outages because of failures on the distribution system. Utility Dive "ERCOT successfully navigates heat wave, new peak demand record" https://www.utilitydive.com/news/ercot-successfully-navigates-heat-wave-new-peak-demand-record/725197/

[13] Data from ERCOT. https://www.ercot.com/gridinfo/generation

[14] Generation data from ERCOT does not include the contribution of behind the meter solar. The load profiles shown are therefore net of the BTM solar. In the 8-month period ending in August of 2024, BTM solar provided about 3.3 TWh, compared to 26.0 TWh from utility-scale systems in all of Texas (not just ERCOT).

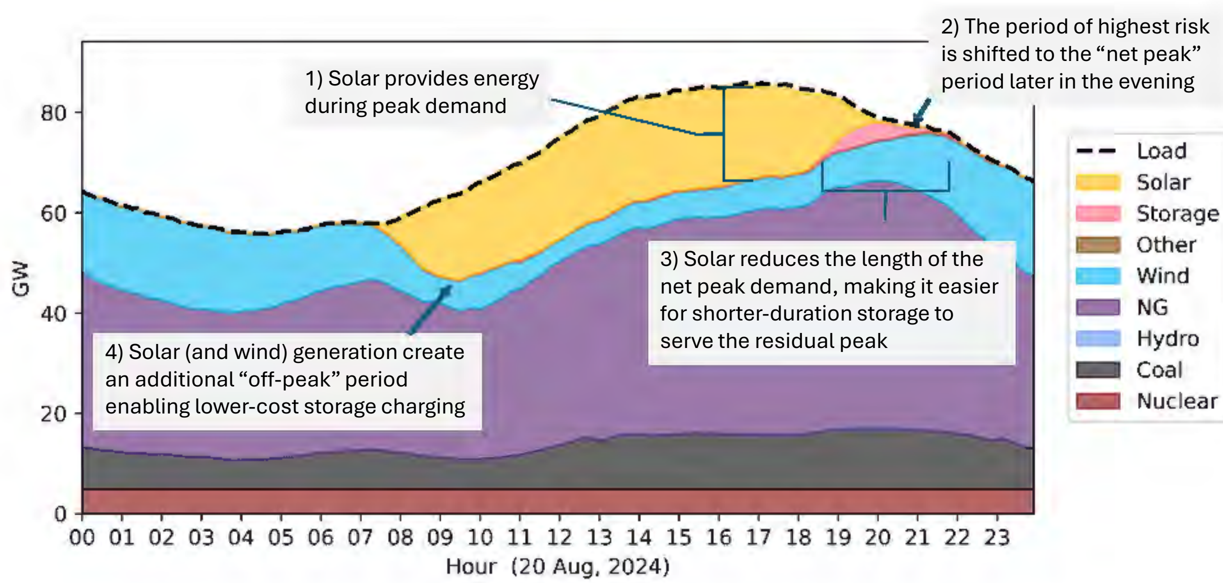


Figure 4. Generation resource mix on August 20, 2024, highlighting four impacts of solar on ERCOT's ability to achieve reliable operation

NG = natural gas

- **Solar significantly contributed to meeting peak demand.** During the hour of peak demand, solar generated at about 18 GW (generating at above 80% of its theoretical potential), providing about 21% of total generation. Solar's significant generation during the peak demand period reduced the risk of an outage during this period and therefore the amount of generation capacity needed from other sources to maintain reliability.
- **Solar shifted the period of highest risk to the evening.** Because of the significant solar generation during the period of highest demand, the period of highest risk was shifted to later in the evening. This shift is often characterized by examining the "net demand" defined as normal demand minus the contribution of certain renewable resources (typically solar or solar plus wind). The peak net demand (net peak) therefore represents the maximum instantaneous generation required from nonrenewable generators and storage. During the 5-minute period of the absolute peak (85.9 GW at 4:45 p.m.), solar generation reduced the net demand to 67.2 GW. This is substantially lower than the day's peak net demand of 78.6 GW, which occurred at 7:55 p.m., when solar output had dropped to near zero.[15]

  This shift in the net demand period increased the probability of wind being available during net load peaks.[16] Wind often has a significantly lower-than-average availability

[15] Historically, NERC forecasts the hour of peak demand (which typically occurs between 3 and 5 p.m.) to estimate system risk. However, in some systems with significant solar (such as ERCOT and California), NERC now forecasts the net peak (removing the contribution of solar) as the period of highest risk. NERC 2024 Summer Reliability Assessment

[16] Harrison-Atlas et al. "Temporal complementarity and value of wind-PV hybrid systems across the United States" https://doi.org/10.1016/j.renene.2022.10.060

during summer afternoon peaks.[17] It provided only about 6 GW to the ERCOT grid during the period of absolute peak, despite an installed capacity of about 38.7 GW. Wind generally has higher availability in the evening, as shown previously in Figure 4 and later in Figure 9.

- **Storage provided a meaningful contribution to the net peak demand, enabled by solar generation.** Although solar by itself did not reduce the net peak demand past sunset, it changed the shape of the net peak period by making it shorter. Figure 5 shows this by comparing the total load (black line) and the net load after the contribution of solar was removed (dotted black line). This allows shorter-duration (and less-costly) storage to provide reliable capacity. Storage in ERCOT provided as much as 3.9 GW (about 4%–5% of total generation) during this period.

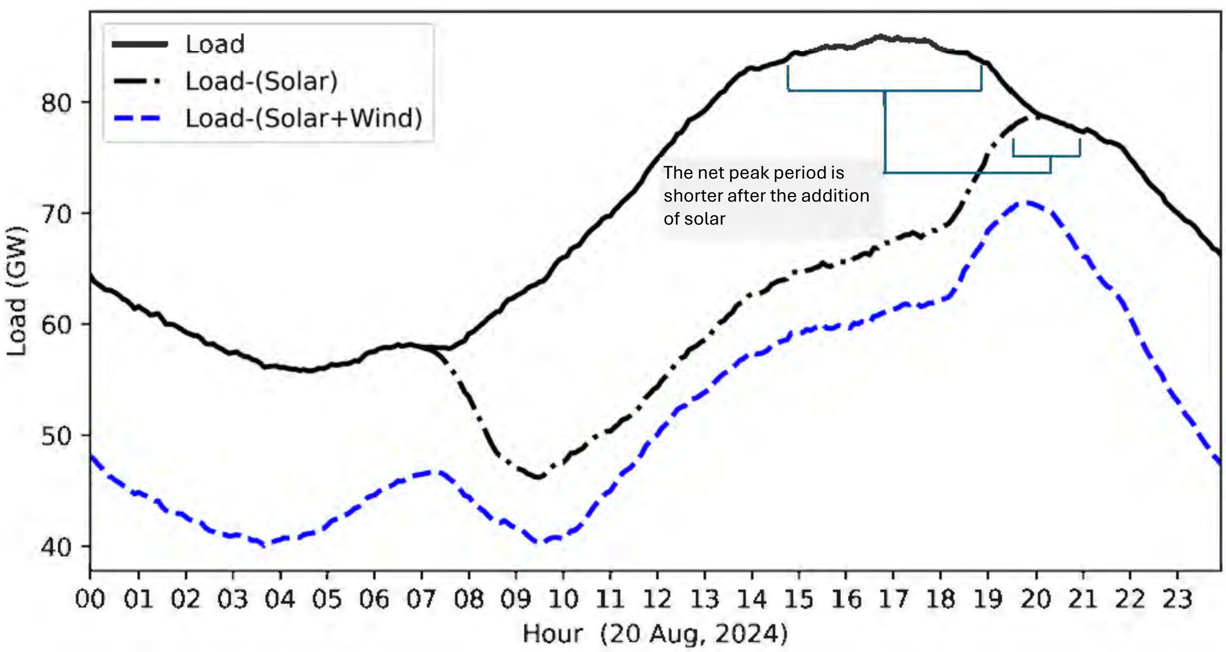


Figure 5. Solar reduces the length of the net peak demand period, reducing the duration of storage required while also increasing the amount of "off-peak" energy available for storage charging.

- **Solar (and wind) increased the availability of off-peak energy for storage charging.** Most recently deployed batteries have relatively short duration (4 hours or less) and generally must recharge every day to provide reliable capacity during extended periods of hot weather. During periods of high temperatures, nighttime demand often stays relatively high. Although there is plenty of spare thermal capacity (coal and gas) for recharging, storage may be forced to purchase power at prices set by relatively high-priced generators. However, solar generation in the late morning and wind overnight reduced the net demand, creating longer or "deeper" off-peak periods as shown in

[17] NERC 2024 Summer Reliability Assessment

Figure 5 (with the net load including wind, shown in blue)—which allowed lower-cost charging from existing thermal units.[18]

Overall, during the peak summer period in 2024, ERCOT met demand with a combination of legacy resources (natural gas and other thermal resources) and the more recent additions of solar and energy storage. The contribution of solar and storage will continue to grow as more of these resources are deployed. As of September 2024, utilities and developers in Texas have added (cumulatively) about 19 GW of solar and 5 GW of batteries, mainly in the last few years, as shown in the solid bars in Figure 6.[19] That is still much less than the 67 GW of natural gas and 14 GW of coal, with installations that date back to before 1960.

Figure 6 also shows estimates of future capacity additions, including those that have been completed as of August 2024, or are under construction or in various stages of approval. The continued growth of both solar and storage is expected to supply an increasing fraction of demand on hot summer afternoons and evenings.[20]

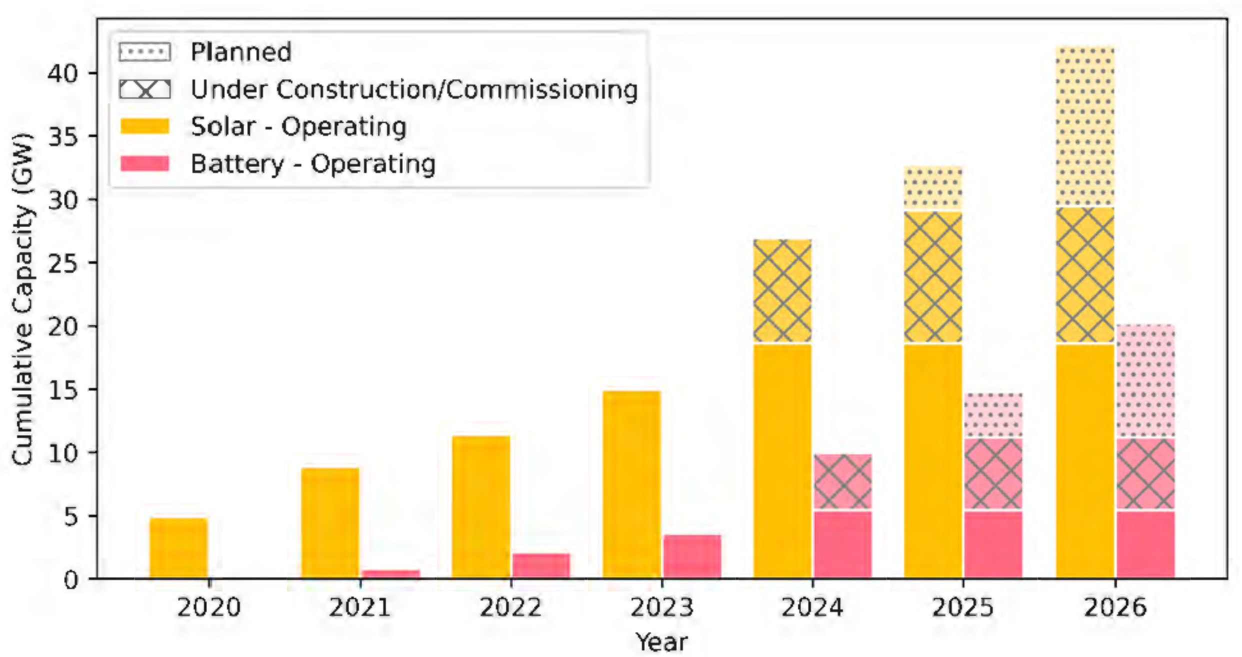


Figure 6. Cumulative solar and storage deployment in ERCOT shows significant growth since 2020 with further growth expected

Values for 2024 are as of August from EIA 860m

[18] The overall change in shape of the net load that results from significant solar deployment is characterized by a low net demand in the middle of the day, and a rapid increase in net demand towards sunset. The resulting shape is sometimes referred to as the duck curve. https://www.nrel.gov/docs/fy16osti/65023.pdf

[19] EIA Form 860m data https://www.eia.gov/electricity/data/eia860m/

[20] NREL Standard Scenarios. https://www.nrel.gov/analysis/standard-scenarios.html

2.2 Other Regions

In other parts of the country, demand on peak days was met by different mixes of legacy thermal, hydropower, renewable, and storage resources, often supplemented by imports from other regions via transmission. However, many regions are now seeing significant contributions from solar.

Although some regions like ERCOT only report utility-scale solar generation, contributions from solar include both utility-scale and behind-the-meter (BTM) systems. The actual contribution from BTM solar toward meeting peak demand can be difficult to determine because it is often not reported. However, some regions report estimated BTM solar generation, and the significant role of BTM solar can be observed in the ISO New England (ISO-NE) region—which corresponds to NERC's NPCC-New England region.[21] Figure 7 shows the generation mix on the peak day (July 16), highlighting the contributions from both BTM and utility-scale solar. Notably, most of New England's solar is in the form of BTM, which was able to provide about 12% of the system generation during the peak demand hour, with utility-scale solar contributing an additional 2%.

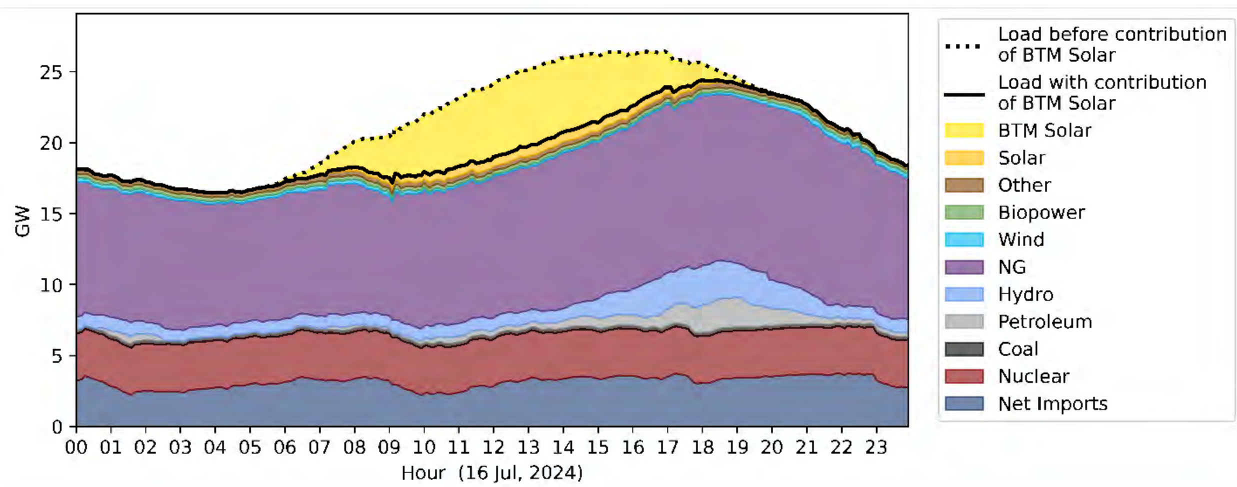


Figure 7. Generation resource mix on July 16, 2024, in the ISO-NE region, showing the large contribution of behind-the-meter solar

The figure also shows the significant role of dispatchable hydropower as well as electricity imports from other regions. New England is also one of the few regions of the country that relies on oil-fired peaking units. These units are operated relatively infrequently because they have high fuel costs and are among the most expensive to operate.

Although ERCOT has primarily utility-scale solar and New England has mostly BTM solar, California has large quantities of both. This solar capacity provided a significant benefit during California's peak demand day on September 5.

[21] https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/daily-gen-fuel-type

Figure 8 shows the generation mix on the peak day for the California ISO (CAISO) area, which corresponds to about 80%[22] of California's electricity demand.[23] Only utility-scale solar is shown, but CAISO reported more than 15.7 GW of BTM solar in its system in addition to the more than 18.5 GW of utility-scale solar in 2024.[24] The presence of BTM solar is reflected in the load shape, which would include more load in the middle of the day in the absence of BTM solar, and shifts the load peak to later in the day, even before the contribution of utility-scale solar.

During the peak hour, about 24% of CAISO's demand was met by utility-scale solar.[25] The resulting net load after the contribution of solar (lower dashed line) creates a steep but short net peak that can be cost-effectively met with energy storage, with its ability to rapidly increase output.[26] During the hour of peak net demand, storage provided about 13% of total generation, with the remainder provided by natural gas, hydropower, imports, and other resources including wind.[27] Figure 8 also shows the significant storage charging occurring in the early morning and during the late morning off-peak period. This off-peak period is a result of substantial solar generation occurring before the afternoon increase in demand as previously shown in Figure 4 and Figure 5.

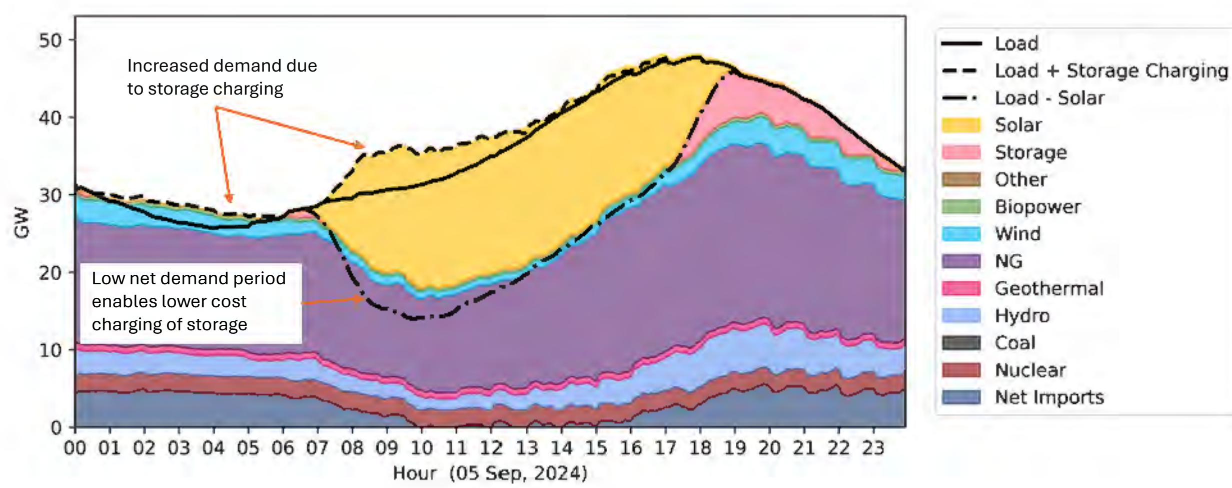


Figure 8. Generation resource mix on September 5, 2024, in the CAISO region, showing the large contribution of solar and storage toward meeting peak demand

---

[22] CAISO Key Statistics September 2024 https://www.caiso.com/documents/key-statistics-sep-2024.pdf

[23] Data from https://www.caiso.com/todays-outlook/supply. Although NERC's SRA evaluated the slightly larger WECC-CA/MX region, complete data for that region is not publicly available.

[24] https://www.caiso.com/documents/april-8-solar-eclipse-technical-bulletin-march-11-2024.pdf

[25] Because of the shift in peak load caused by BTM solar, utility-scale solar output has already begun to drop. In the hour of peak demand, utility-scale solar is generating at about 38% of rated capacity and dropping rapidly.

[26] NREL Storage Futures Study Key Learnings for the Coming Decades https://www.nrel.gov/docs/fy22osti/81779.pdf

[27] In addition to having more storage capacity (by power) than ERCOT, California's storage tends to have more energy (duration) per unit of power capacity. For a discussion of drivers behind regional duration, see https://www.nrel.gov/docs/fy23osti/85878.pdf.

In other parts of the country, such as those served by MISO, there is relatively less installed solar and storage capacity, so the solar and storage share of peak day generation was significantly lower than in regions such as Texas, New England, and California. Peak demand in these other areas was reliably met largely with thermal generators and with smaller contributions from hydropower, solar, and wind. Figure 9 provides an example of the generation mix in MISO on the peak demand day on August 26.[28] Compared to the other regions examined above, MISO remains more dependent on natural gas and coal generation. Regions like MISO have significant opportunity to deploy more solar and storage to help meet summer peak demand in the future.[29]

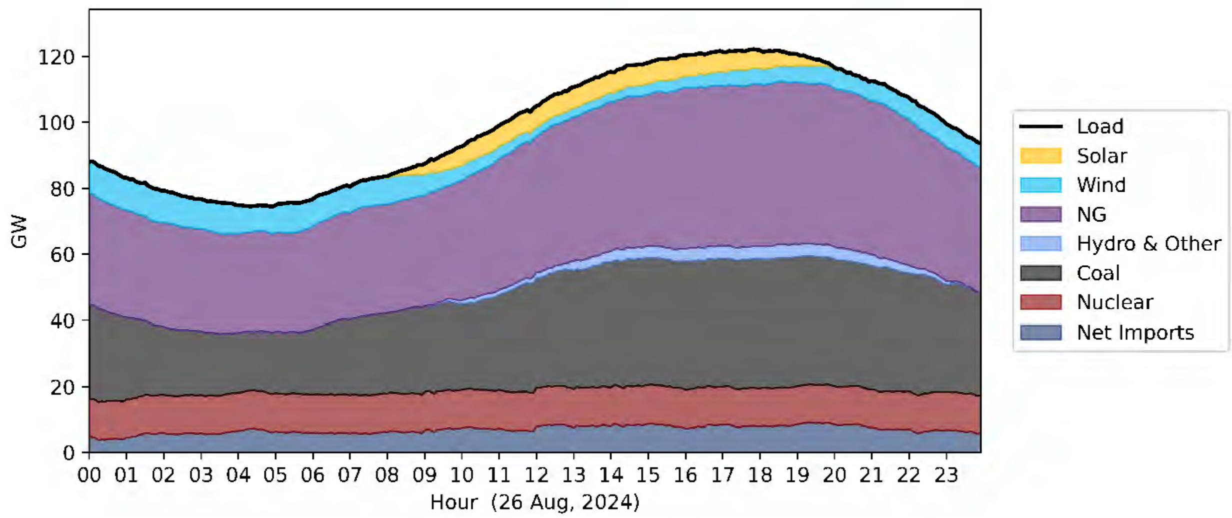


Figure 9. Generation resource mix on August 26, 2024, in the MISO region, showing limited contribution from solar and other low-carbon resources

[28] https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-report-archives/#nt=%2FMarketReportType%3ASummary&t=10&p=0&s=MarketReportPublished&sd=desc

[29] Frazier et al. Assessing the potential of battery storage as a peaking capacity resource in the United States. https://www.sciencedirect.com/science/article/pii/S0306261920308977

3 Maintaining Reliability During Future Summer Peaks

Both the supply and demand of electricity are changing quickly. Demand is growing to power data centers and an expanding digital economy, a U.S. manufacturing renaissance, and the electrification of transportation and other end uses[30]—all while the generation mix is rapidly evolving. Historically, the grid has primarily relied on thermal and hydropower resources to keep the lights on during summer peaks. But increasingly rapid deployment of grid-scale solar and storage are enabling these technologies to play a larger role.[31]

Summer 2024 demonstrated the combined ability of solar and storage to provide valuable capacity during summer peaks in diverse regions across the country, including Texas, California, and New England. Greater solar output increased the availability of clean generation during hot summer afternoons, shortened net peaks, and shifted those peaks to the evenings. As the sun set, grid-scale battery storage played a crucial role by discharging stored energy that helped maintain grid reliability until cooler temperatures reduce loads overnight.

The performance of the Texas and California power grids in summer 2024 showed that solar and storage can work together to help power the grid through peak summer demand days. Storage with relatively short duration (2–6 hours) can provide a significant portion of summer peak demand in all regions of the United States.[32]

3.1 Projected Solar and Storage Growth

In the coming years, even more solar and storage is planned to be connected to the grid. Figure 10 shows projections from the Energy Information Administration (EIA) with estimates of more than 140 GW of grid-scale solar installed in the United States by the end of 2025, compared to 109 GW as of August 2024. [33] These data also project grid-scale battery storage will grow from 22 GW to 38 GW over the same time frame. There is also a large amount of solar and storage resources waiting in interconnection queues planned for installation beyond 2025. Based on these trends, solar and storage will likely have a growing role in keeping the lights and air conditioning working on the hottest summer days in more regions across the country.[34]

[30] Wood Mackenzie projects data centers will add 25 GW of new demand, manufacturing will add 15 GW, electrification will add 7 GW, by 2029. US utilities to face significant challenge as power demand surges for the first time in decades | Wood Mackenzie. Grid Strategies also identifies data centers, large industrial loads, and electrification as key drivers of growing demand: National-Load-Growth-Report-2023.pdf (gridstrategiesllc.com).
[31] Denholm, P. *Explained: Maintaining a Reliable Future Grid with More Wind and Solar*. National Renewable Energy Laboratory. NREL/FS-6A40-8729 https://www.nrel.gov/docs/fy24osti/87298.pdf
[32] Blair, N., et al. *Storage Futures Study: Key Learnings for the Coming Decades*: National Renewable Energy Laboratory. NREL/TP-7A40-81779
[33] Data includes Alaska and Hawaii. EIA 860m https://www.eia.gov/electricity/data/eia860m/
[34]https://emp.lbl.gov/queues

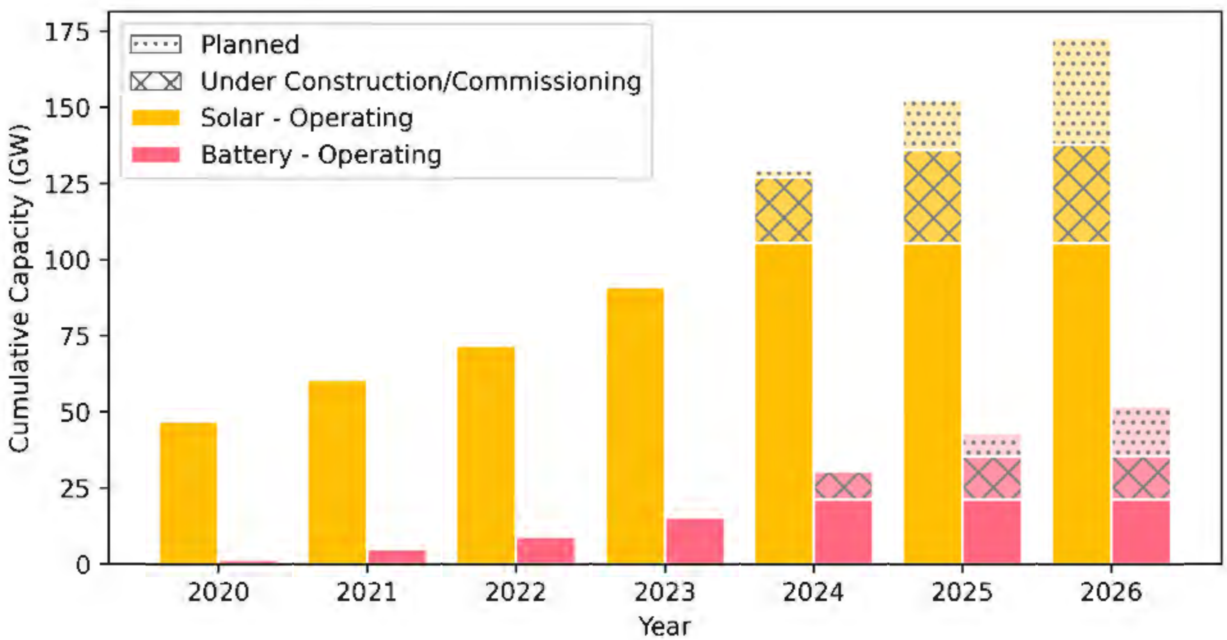


Figure 10. National projections from the EIA show substantial near-term growth of both solar and battery storage is expected

Values for 2024 are as of August from EIA 860m

3.2 Evolving Challenges and Opportunities

Leveraging the capabilities of diverse generation resources can improve reliability. Each resource type can serve specific needs, enabling the combined portfolio to provide consistent reliable power during peak hours. The power grid will never rely solely on solar and storage to meet all system needs. As load changes, so will the resource mix. In the near term, thermal resources will continue to play a critical role in meeting demand, including during system peaks, though their utilization is expected to decline as solar, storage, and wind resources grow.

The integration of more diverse generation resources involves changing the processes used to ensure sufficient generation capacity is available to serve demand at all times.[35] Historically, planners have forecast peak loads and maintained nameplate generation capacity equal to that peak load plus a reserve margin to cover outages and forecast uncertainty. As more renewable and storage resources connect to the bulk power system, different resources provide different combinations of services or value to the grid. This can cause the hours during which the grid is most stressed to shift to later in the day during the summer, as has happened with growing solar deployment in Texas and California, as well as to periods of low solar output in the winter. In the future, it will be increasingly important for grid planners and operators to consider other possible periods of grid stress in addition to summer peaks.

[35] ESIG Redefining Resource Adequacy for Modern Power Systems https://www.esig.energy/resource-adequacy-for-modern-power-systems/

In this context, more sophisticated probabilistic analysis that evaluates contributions of all resources during times of greatest system stress is needed to ensure the resource mix can serve total demand in both summer and winter as load grows, demand patterns shift, and the role of renewable generation increases.[36] Many grid operators have recently implemented or are currently implementing such approaches.[37] Careful and rigorous planning and additional improvements to planning frameworks is important to ensure continued reliable system operation.

Alongside solar, storage, and wind, other clean resources can bring a variety of benefits to the power system in future summers. These resources include supply-side technologies such as nuclear, geothermal, and long-duration storage that can provide power during periods of greatest system need. They also include transmission infrastructure to bring power to where it is needed most, connect new resources to loads, and improve power system resilience to extreme weather. Innovative demand-side technologies can play an important role, too, enabling consumers to implement grid-edge solutions that reduce peak demands and serve as virtual power plants while reducing customer and system costs.[38] The Bipartisan Infrastructure Law[39] and Inflation Reduction Act[40] are investing tens of billions of dollars into demonstrating and deploying this suite of new technologies. At the same time, the Federal Energy Regulatory Commission is reforming transmission planning and interconnection processes to facilitate the market entry of new resources.[41,42] With continued rigorous planning, these new resources can build on the value that thermal plants, hydropower, solar and storage, and wind are already providing to keep the power system operating smoothly during both summer peaks and other future periods of grid stress.

---

[36] DOE. The Future of Resource Adequacy. 2024 The Future of Resource Adequacy Report.pdf (energy.gov)
[37] PJM adopted a marginal ELCC capacity accreditation framework for its 2025-2026 capacity auction: https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240130-3113&optimized=false. ISO New England is developing a Marginal Reliability Impact accreditation framework that it plans to implement beginning June 1, 2028: https://www.iso-ne.com/committees/key-projects/capacity-auction-reforms-key-project.
[38] U.S. Department of Energy (DOE). The Future of Resource Adequacy. 2024 The Future of Resource Adequacy Report.pdf (energy.gov)
[39] Infrastructure Investment and Jobs Act. https://www.congress.gov/bill/117th-congress/house-bill/3684/text.
[40] Inflation Reduction Act. https://www.congress.gov/bill/117th-congress/house-bill/5376.
[41] Federal Energy Regulatory Commission. Order 2023. https://www.ferc.gov/media/e-1-order-2023-rm22-14-000.
[42] Federal Energy Regulatory Commission. Order 1920. https://www.ferc.gov/media/e1-rm21-17-000.

Republicans to grapple with clean energy tax credit repeal amid budget talks

Wednesday, February 26, 2025 5:12 PM ET

By Zack Hale
Commodity Insights

Congressional Republicans will take a hard look at repealing or modifying the Inflation Reduction Act's clean energy subsidies as US House and Senate negotiators seek alignment on a budget resolution calling for up to $4.5 trillion in tax cuts, a panel of tax policy experts predicted Feb. 26.

But whether Republicans employ an "ax" or "scalpel" approach to the Inflation Reduction Act's (IRA) tax credits for clean energy generation and advanced manufacturing remains to be seen, panelists said during a policy forum convened by the American Council on Renewable Energy (ACORE).

The trade group hosted the event in Washington, DC, a day after House Republicans narrowly advanced a budget reconciliation resolution intended to deliver on President Donald Trump's "energy dominance" agenda, among other priorities.

The House resolution — passed by a 217-215 vote — sets in motion a process for Republicans on individual committees to develop more detailed legislation that complies with their topline budget instructions.

Republicans appear to be coalescing around House Speaker Mike Johnson's one-bill budget reconciliation approach for addressing Trump's top legislative priorities, which include extending the 2017 tax cuts the president signed into law. The Senate passed its own $340 billion budget resolution on Feb. 21 that would only address Trump's policy priorities on immigration, national security and US energy production.

Under congressional budget reconciliation rules, the House and Senate must pass identical budget resolutions. Reconciliation procedures, used by Democrats to pass the IRA in 2022 and Republicans to pass the Tax Cuts and Jobs Act (TCJA) in 2017, allow the Senate to avoid the chamber's 60-vote filibuster threshold.

House resolution lacks 'breathing room'

Pressure on Republican tax writers to raise offsetting revenues "will phase up or down, depending on what the ultimate budget resolution answer is," William Davis, a partner at Capitol Tax Partners, said during the ACORE event.

Davis, previously tax policy counsel to former Rep. Tom Reed (R-NY), noted that 18 House Republicans wrote to Johnson last summer warning that full repeal of the IRA's clean energy subsidies would threaten ongoing construction projects in GOP congressional districts.

He said Republicans are currently grappling with actions that could raise energy costs for consumers, such as the repeal of tax credits affecting power generation or energy component manufacturing.

"Staff are hard at work thinking through all the various implications and what the impacts on the economy and on the energy sector would be should they go down that road," Davis said.

Travis Cone, a partner at the public relations firm CGCN, said the House budget resolution's instruction to the Ways and Means Committee to produce $4.5 trillion in tax cuts over 10 years does not leave much "breathing room" for policy changes beyond simply extending the TCJA.

"President Trump spoke on the campaign trail about waiving taxes on Social Security, tips, and a whole host of other things," said Cone, who joined CGCN after 13 years as a Republican staffer in the House and Senate. "Those are very expensive big-ticket items, and right now they've given them enough headroom to essentially extend TCJA and nothing more."

Alice Lin, former deputy assistant secretary at the US Treasury Department during the Biden administration, recommended thinking about potential repeal of the IRA's tax credits as "not a separate political end unto itself."

Repeal considerations will be "an exercise in figuring out how to bridge that gap between what you want to spend on and what the [budget] instruction is," said Lin, who was previously a tax adviser in the House and Senate.

"When I think about all the equities across the various credits, it's a question of what is going to fulfill that goal with the least pain in terms of actually stitching the votes together on the floor," Lin said.

Hill staff eye repurposing, consolidating credits

Cone predicted that the IRA's prevailing wage and apprenticeship requirements for bonus tax credit rates would likely be "gone" under a final GOP reconciliation bill. The Treasury Department's IRA tax credit guidance, finalized in June 2024, encourages union labor agreements.

"It's a Biden initiative, it drives up some of the costs, and Republicans hate it," Cone said of the Treasury guidance.

Meanwhile, Republicans could seek to repurpose the IRA's production tax credit for carbon-free electricity to reward baseload power generation, Cone added. Sen. Ron Wyden (D-Ore.) led the effort to transition the IRA's carbon-free production tax credit to a more technology-neutral approach starting in 2025.

"A lot of the conversation I've heard on the Hill right now is, 'Well, we may actually co-opt Wyden's idea of a tech-neutral credit, but we'll just change the criteria for meeting it,'" Cone said. He suggested that such criteria could hinge on metrics such as a power plant's annual capacity factor and domestic content "vis-à-vis supply chains."

Cone stressed that those ideas are hypothetical until the House and Senate reach consensus on an overarching budget resolution.

Anna Taylor, deputy leader of Deloitte's tax policy group, put the odds of Republicans passing a final reconciliation bill before the end of the year at "more likely than not."

The question of repealing IRA clean energy subsidies "will not be put to these members in a vacuum," said Taylor, who was previously tax and trade counsel to former Senate Majority Leader Charles Schumer (D-NY).

"Are you going to be willing to stand in the way of your president's agenda because you don't get what you want in this space?" Taylor said during the Feb. 26 event. "I think ultimately, you're going to have a lot of members who are asked that question, who are supportive of the [IRA] credits, and we'll see."

This article was published by S&P Global Market Intelligence and not by S&P Global Ratings, which is a separately managed division of S&P Global.

Staff Exhibit JTG-6

PROJECT SPONSORED BY

CLEAN GRID INITIATIVE

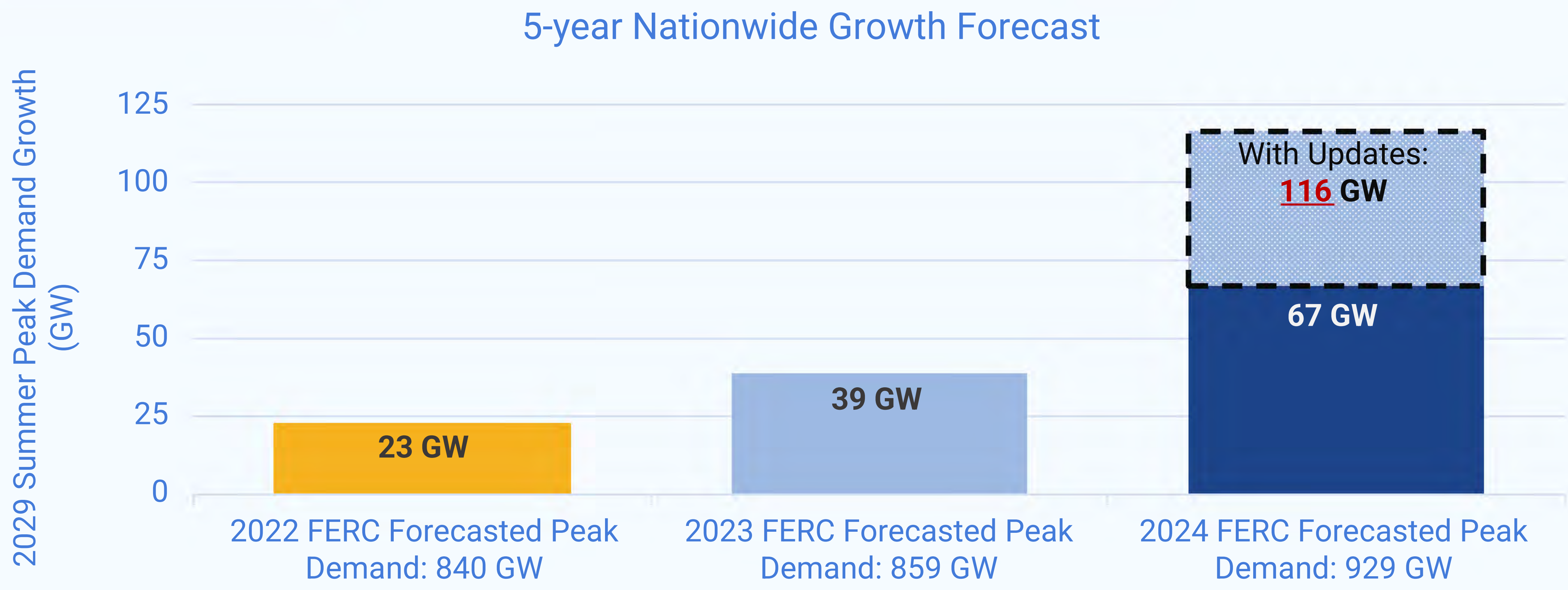
GridStrategies

Strategic Industries Surging – *Midcontinent Power Sector Collaborative (February 2025)*

John D. Wilson, Zach Zimmerman, and Rob Gramlich

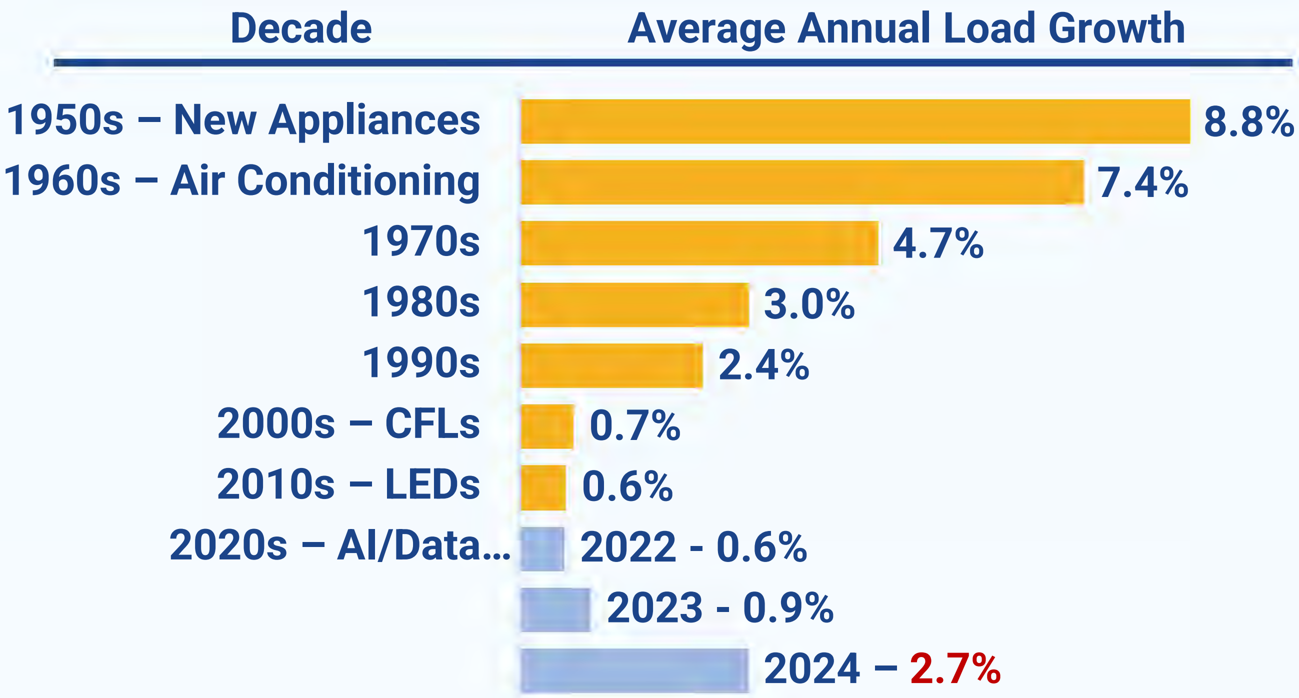
REPORT PUBLISHED DECEMBER 2024

Five-Year Load Growth Up Five-Fold to 116 Gigawatts



GridStrategies

A Scramble to Respond to Growing Load



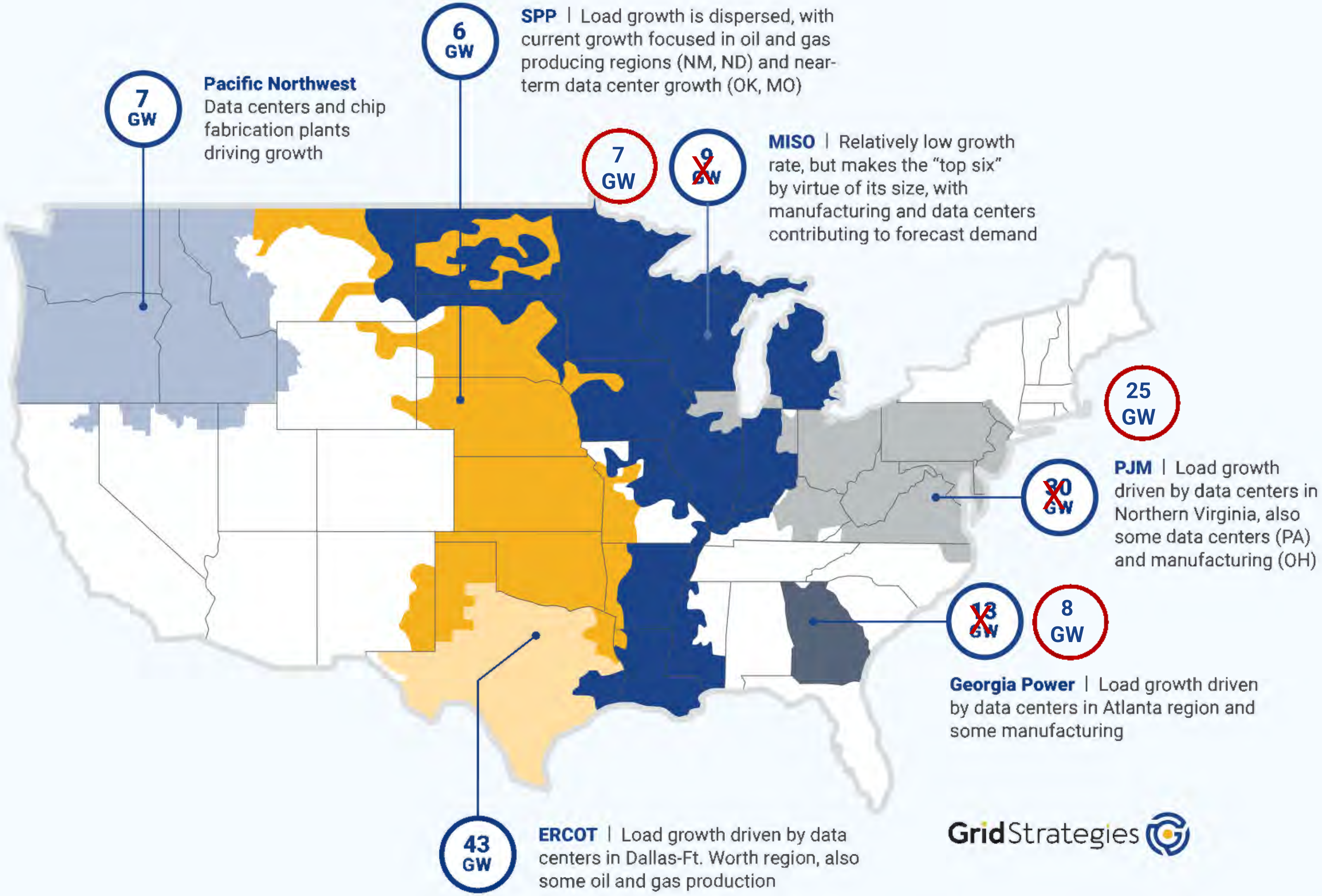
Grid Strategies

Strategic Industries Driving Load Growth Across Regions

Near-Term Load Drivers	Data Centers	Manufacturing	Electrification
Arizona Public Service	S		
CAISO	S		S
Duke	S	S	
ERCOT	S	S	
Georgia Power	S	S	
ISO-NE			S
MISO	S		S
NYISO	S	S	S
Pacific Northwest	S	S	
PJM	S	S	S
SPP	S		

GridStrategies

Six Regions Driving Load Growth Through 2029



Planning Areas with Sharpest Increase in 2024 Load Forecast

Updates from published reports:

- PJM 2025 forecast increased by 10.4 GW (not 15.2 GW)
- Georgia Power 2025 IRP forecast increased by 2.2 GW (not 7.3 GW)
- MISO 2024 white paper decreased forecast by 2.0 GW

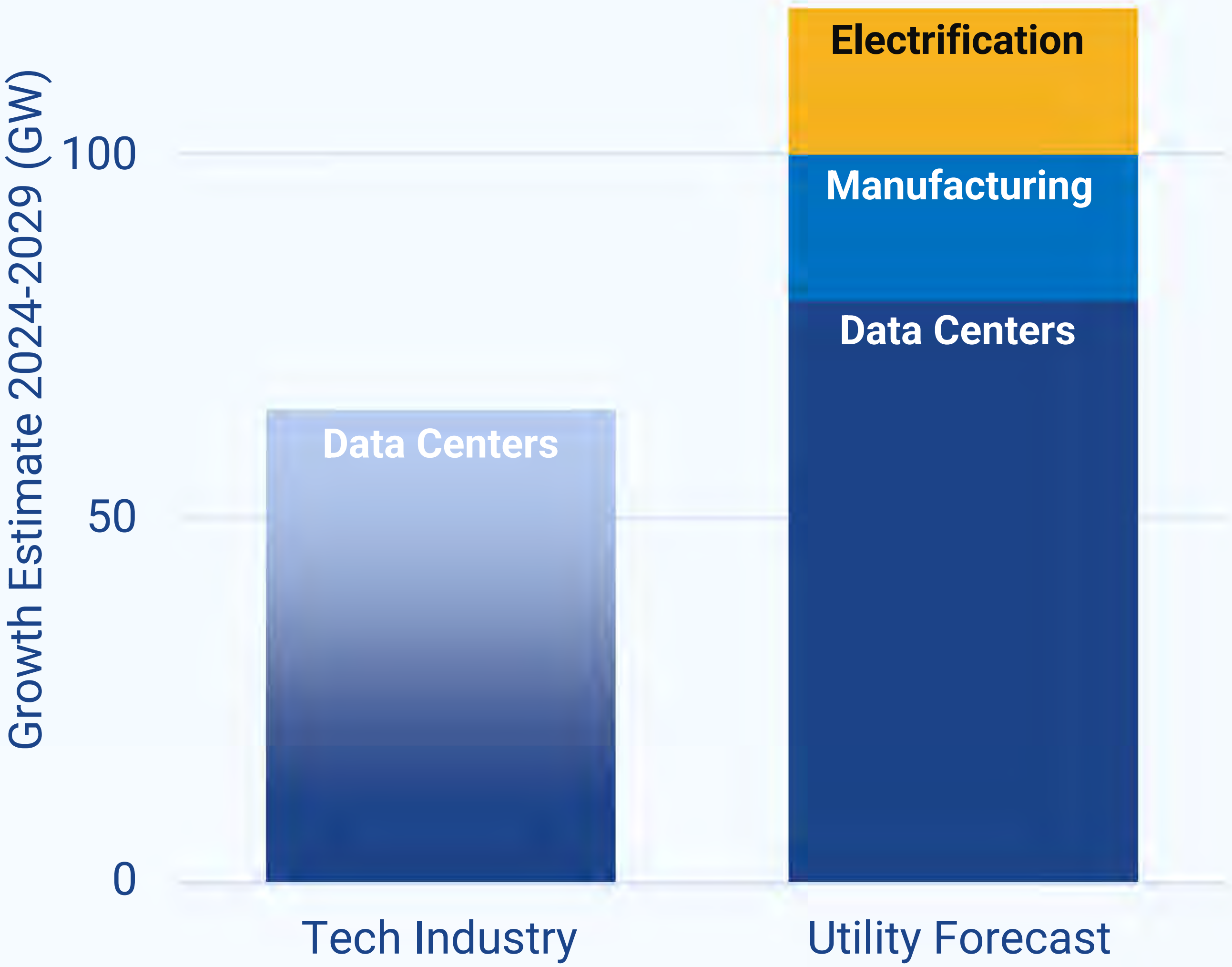
Planning Areas with Greatest Increase in Summer 2029 Peak Demand

	2029 Peak Demand						
Planning Area	2022 Forecast (GW)	2023 Forecast (GW)	2024 Forecast (GW)	Forecast Updates (GW)	Forecast Increase (GW)	Forecast Increase (Percent)	Total Growth Through 2029 (GW)
ERCOT	84.4	89.6	88.1	+ 36.9	40.6	48.1%	42.8
PJM	153.3	156.9	165.7	+ 10.4	22.7	14.8%	24.8
Georgia Power	16.3	17.3	22.4	+ 2.2	8.4	51.6%	7.9
MISO	132.4	133.0	138.4	- 2.2	4.1	3.1%	7.1
Pacific Northwest	37.4	38.4	38.5	+ 2.0	3.1	8.2%	7.4
SPP	56.6	59.5	62.5		5.9	10.4%	6.3
Duke Energy (North & South Carolina)	33.9	36.2	36.6		2.7	7.8%	2.6
Arizona Public Service	8.7	9.8	9.9		1.2	13.6%	1.5
NYISO	31.5	32.3	32.3		0.9	2.8%	4.6
Tennessee Valley Authority	31.8	32.4	32.5		0.7	2.2%	1.4
All other planning areas	251.2	250.5	249.5		-1.7	-0.7%	10.0
Total	840.5	858.9	879.8	+ 49.5	88.8	8.2%	116.3

Data Center Forecast: Bottom Up vs Top Down

In the aggregate, the power industry does not have access to the data it needs to accurately forecast data center load.

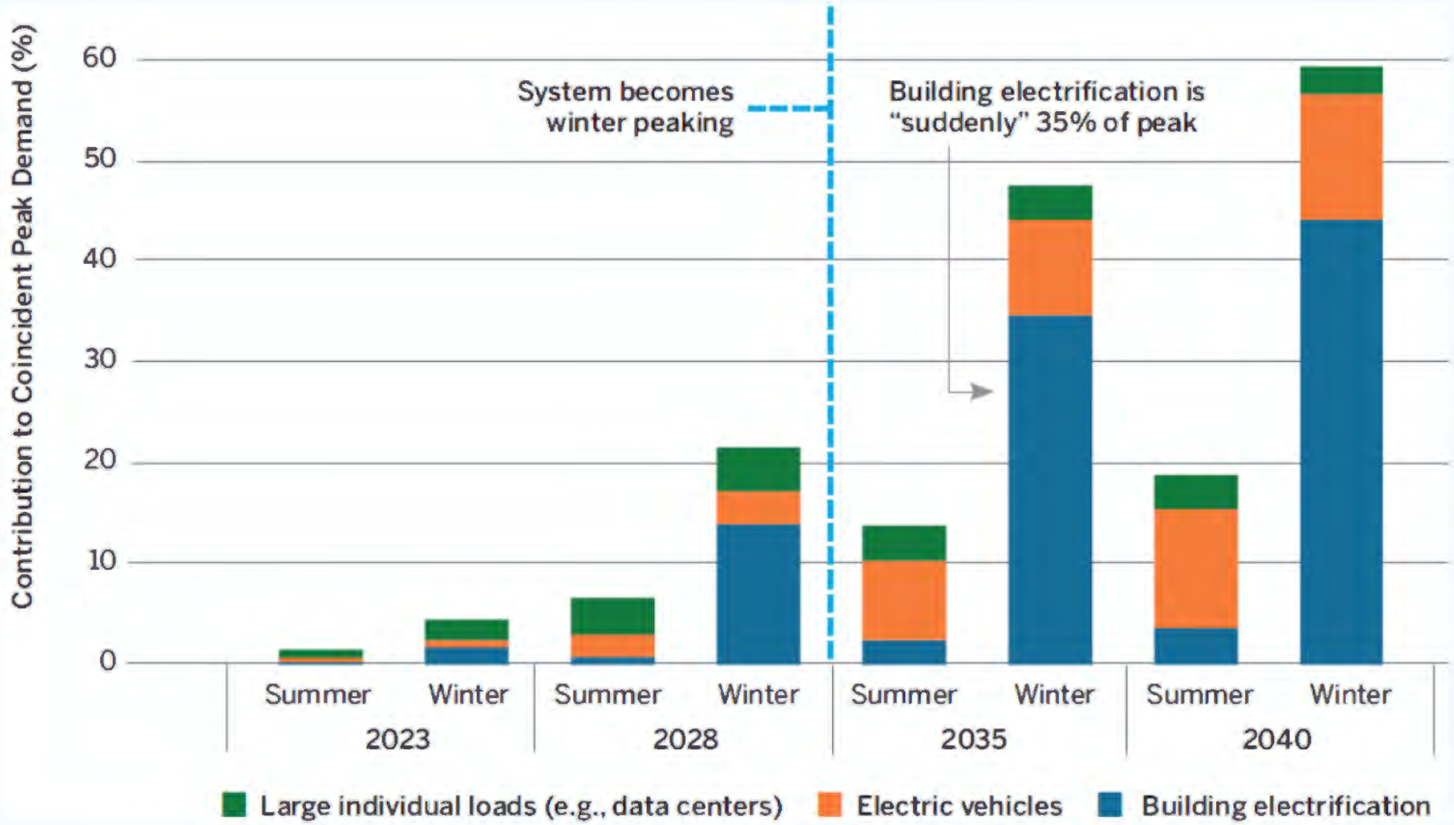
- Industry specialists estimate five-year data center demand growth from as little as 10 GW to as much as 65 GW through 2029.
- Only some utilities break out data centers from other large load drivers. Grid Strategies' rough estimate of aggregate utility data center load forecasts is about **80** GW. Note that this estimate relies on informed speculation for regions with no published breakout or inconsistent category definitions. This is almost 10% of forecast 2029 load of **929** GW.



GridStrategies

Building and Transportation Electrification Impacts Coming

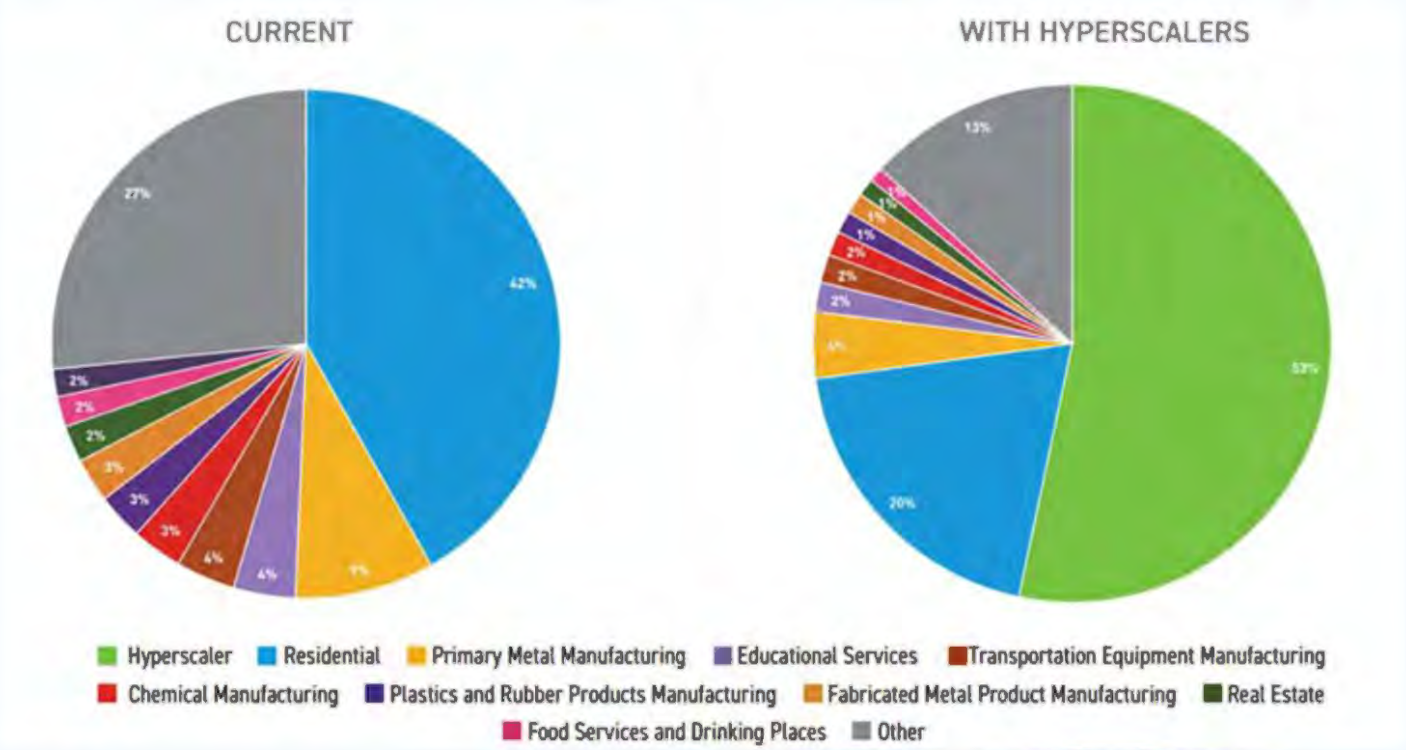
Electrification and Large Load Impacts on New York's Peak Power Demand



New Large Load Tariffs to Reduce Revenue Risks and Improve Forecasts

New report from Energy Futures Group:
Review of Large Load Tariffs to Identify Safeguards and Protections for Existing Ratepayers

Hyperscale Data Centers Could Represent >50% of Indiana & Michigan Power Revenues



NERC Large Load Reliability Standard

NERC: Large data centers presenting new, unique challenges to grid reliability

- **Price Response** – especially crypto mining
- **"Ride-through"** – backup power systems can remove large loads from the grid
- **Normal operations** – AI "training models" can vary load in just seconds

GridStrategies

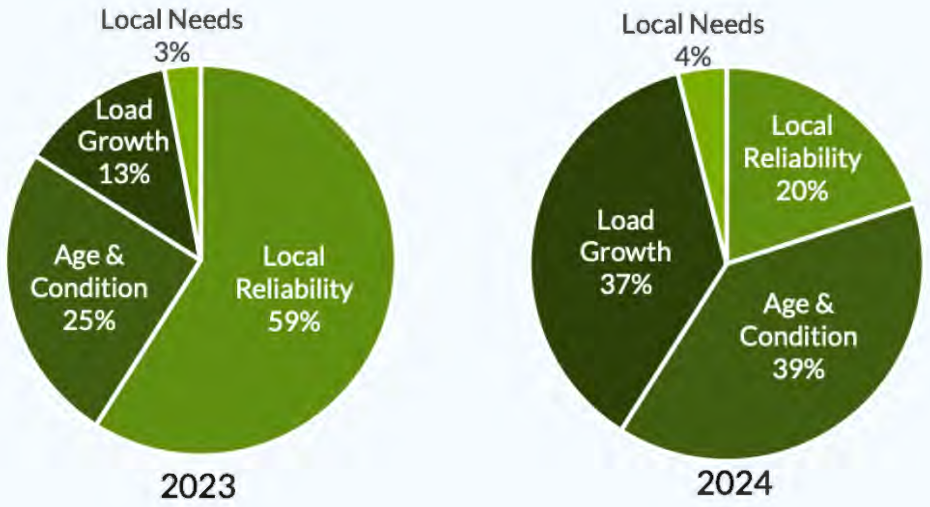
Large Region with Relatively Low Growth

The MISO planning area's 2029 forecast increased from 132.4 GW to 138.4 GW over the past two years, a 4.6% increase. Compared to other planning areas, this increase is relatively low on a percentage basis. However, because MISO is so large, its total load growth increase is relatively large.

In its 2023 transmission planning cycle MISO approved a record setting $9 billion transmission expansion plan citing load growth as a driver of the increase and their draft 2024 plan includes even more projects to address load growth.

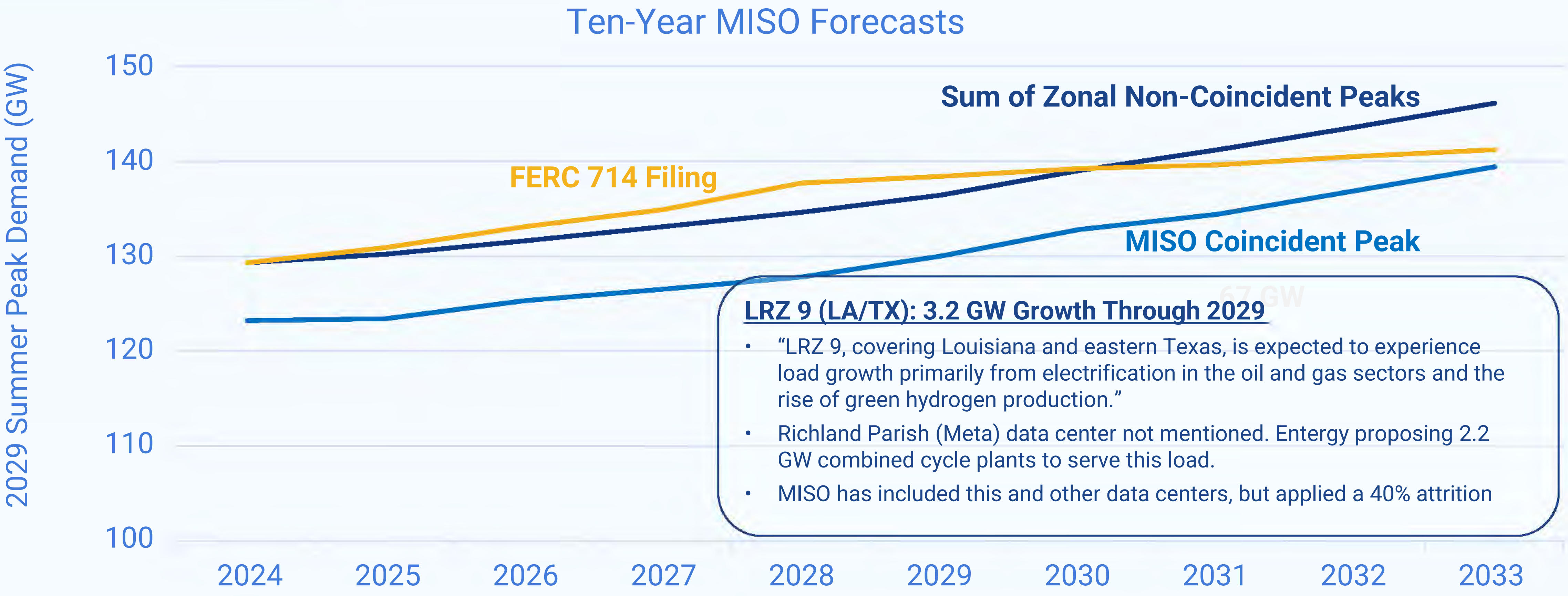
The forecast filed by MISO reflects members' self-reported load forecasts as completed in 2023. MISO is updating its load forecasting method with an anticipated release in December 2024. **Dependence on members' self-reported load forecasts may introduce a lag in the response of MISO's load forecast to the increased pace of load connections.**

MTEP23 vs. MTEP24 Breakdown of Projects by Cost



SOURCES | MISO, MTEP 2023 (September 2024).
MISO, MTEP24 Report Preview (October 2024).

MISO's FERC 714 Filing Compared to December 2024 White Paper (Current Trajectory)



LRZ 9 (LA/TX): 3.2 GW Growth Through 2029

- "LRZ 9, covering Louisiana and eastern Texas, is expected to experience load growth primarily from electrification in the oil and gas sectors and the rise of green hydrogen production."
- Richland Parish (Meta) data center not mentioned. Entergy proposing 2.2 GW combined cycle plants to serve this load.
- MISO has included this and other data centers, but applied a 40% attrition

Observations on MISO Long-Term Load Forecast

MISO's review of load forecast data from load serving entities (February 2025)

- MISO conducts an **annual load forecast assessment**, reviewing a sample of load-serving entities. Review includes methods, inputs, and forecast values. MISO reports timely and compliant responses to supply missing information and make "minor revisions."

MISO stakeholder comments (January 2025)

- Stakeholders **questioned policy adoption as a driver** for vehicle electrification, building electrification, and hydrogen development – these concerns could also be expressed for oil & gas operations.
- Surprising that some load-serving entities have **basic questions about MISO's forecast**. This could suggest that some of the data supplied by these utilities are not optimized for MISO's forecast applications.

Data center forecast method explained in MISO's response to stakeholder comments on Medium and Long-Term Load Forecast (February 2025)

- MISO's data center capacity forecast relies on **publicly available data center announcements** and **third-party estimates**.
- MISO's response states that it assumes publicly announced **data centers will be completed** on schedule, but clarified to Grid Strategies that a 40% attrition rate is included to compensate for supply chain delays, ramp up, and other uncertainty.
- MISO considers there to be **minimal risk of double-counting**, and cross-references with Expedited Project Review (EPR) process data – but stakeholders questioned this approach.
- MISO is **not releasing details of its data center forecast**.

Energy Systems Integration Group (ESIG): Large Load Task Force

I am leading the Large Load Forecasting team for ESIG's LLTF

- Looking for participants (generally, must join ESIG) and presenters
- Collecting existing large load forecasting practices
- Evaluating methods for considering speculative requests and certainty
- Exploring potential for national aggregation of confidential data
- Studying how to address policy issues, such as impact of demand flexibility
- Develop recommended best practices

Large Load Task Force: Topical Areas / Project Teams

ESIG

- Data collection on characteristics of AI and other data centers and other large loads.
- Load forecasting
- Interconnection process
- Interconnection performance requirements
- Modeling requirements for interconnection
- Wholesale market options for large loads; co-location of generation and load
- Transmission planning with high shares of large loads
- Resource adequacy with high shares of large loads
- Additionally, LBNL will be leading an effort on regulatory and contractual aspects – tariffs, flexible interconnections and curtailment, contracts.

Thank you!

John D. Wilson
Vice President
jwilson@gridstrategiesllc.com

We offer research and advising on

- Clean Energy Integration
- Business & Policy Solutions
- Regulatory Engagement

Founded in 2017, Grid Strategies works on policy to enable decarbonization and an affordable, reliable electricity system.

Energy Intelligence

REPRINT

JANUARY 26, 2023

WWW.ENERGYINTEL.COM

OIL DAILY®

Staff Exhibit JTG-7

BPX Closes In on Electrifying All Permian Wells

BP's US shale subsidiary BPX is drawing near to powering all of its well sites in the prolific Permian Basin with electricity from the grid.

After hitting the milestone of 80% of Permian wells electrified in 2022, the company is aiming to get to 95% in 2023, BPX CEO David Lawler told reporters on Wednesday.

"What this does for us, is it allows us to have a very low-carbon footprint, and a very low-carbon-intensity barrel of crude oil that's produced," Lawler said.

Operators in the Permian are increasingly looking to electrify their facilities as a way to decarbonize, but the remoteness of the basin and many of its well sites poses a challenge. Pioneer Natural Resources CEO Scott Sheffield said last year that the electric grid in the Permian needs to grow to three to four times its current size to accommodate the E&Ps looking to go electric, and that operators will soon need to start investing in grid infrastructure themselves.

But BPX appears to have beaten them to the punch. Since acquiring its shale assets from BHP in 2018, the company has spent $700 million-$800 million on electrification, including the development of two substations in the Permian. Overall, the company plans to spend $1.3 billion to electrify its Permian operations.

"This massive power infrastructure allows us to supply power to the drilling rigs that we use when we drill the wells," said Lawler. "The overhead power allows us to stimulate or frack the wells with electric frack spreads. We pump the wells with electric submersible pumps, we compress the gas with electric driven compressors. And we operate the controls of the system with compressed air from an electric source as well."

Grand Slam

The key components to BPX's electrification strategy in the Permian are centralized processing facilities, of which the first, Grand Slam, came on line in 2021. Wells receive electricity from the grid and flow to Grand Slam, essentially erasing the need for wellsite compressors, tanks and other equipment that might result in a higher emissions footprint.

New well sites are tied directly to Grand Slam; for older well sites that existed before the electrification program, BPX deploys project teams to connect the wellhead to the facility, then decommissions the now-unneeded equipment, according to Lawler. Decommissioning can take fewer than 30 days.

"Sometimes what you need to do is you have to decommission the site, and then you have to lay the connections over to the central processing facility, you then have to bring in the power," he said. "So what we try to do is bundle those projects together so we can do them very efficiently. But in general, it's a straightforward project. It does take a little bit of time, though, because there can be a fair amount of distance between one of those wells and the [facility]."

The $350 million Grand Slam, which can process 30,000-35,000 barrels of oil per day, also runs off grid power.

"When you come out here, you don't hear any engines running. You don't see massive flare stacks, you don't really see anything, it's largely an emissions-free instrument-air facility," he said.

BPX plans to build three more centralized processing facilities over the next several years. The second, Bingo, is scheduled to come on line in June or July.

>> continued on page 2

What's Left?

While BPX may be ahead of the pack in terms of electrification in the Permian, it has more investments to make before electrifying the whole field. This year, it plans to run three electric rigs on its Permian acreage, but it also plans to run one or two that are not electrified. That's because they will be working in areas that are not yet set up to receive grid power.

BPX is already planning to build more substations to reach more remote areas, and the additional central processing facilities should also support electrification efforts in the coming years, Lawler said.

Elsewhere on the emissions front, BPX is making efforts to have its natural gas certified by a third party. Lawler said the company was "very close" to having 100% of its natural gas certified as low-emissions.

Lawler also told reporters the company had reached "near-zero" routine flaring at its Permian operations last month.

Caroline Evans, Houston

Staff Exhibit JTG-8

Supply Attraction Focus

Historic Southern Star supply

The Rockies Green River Basin

Direct	Echo Springs (Riner, WY), Various plants (DJ Basin)
Pipeline	Colorado Interstate (CIG), Cheyenne Plains (CPP)

The Hugoton/Anadarko (North) Basins

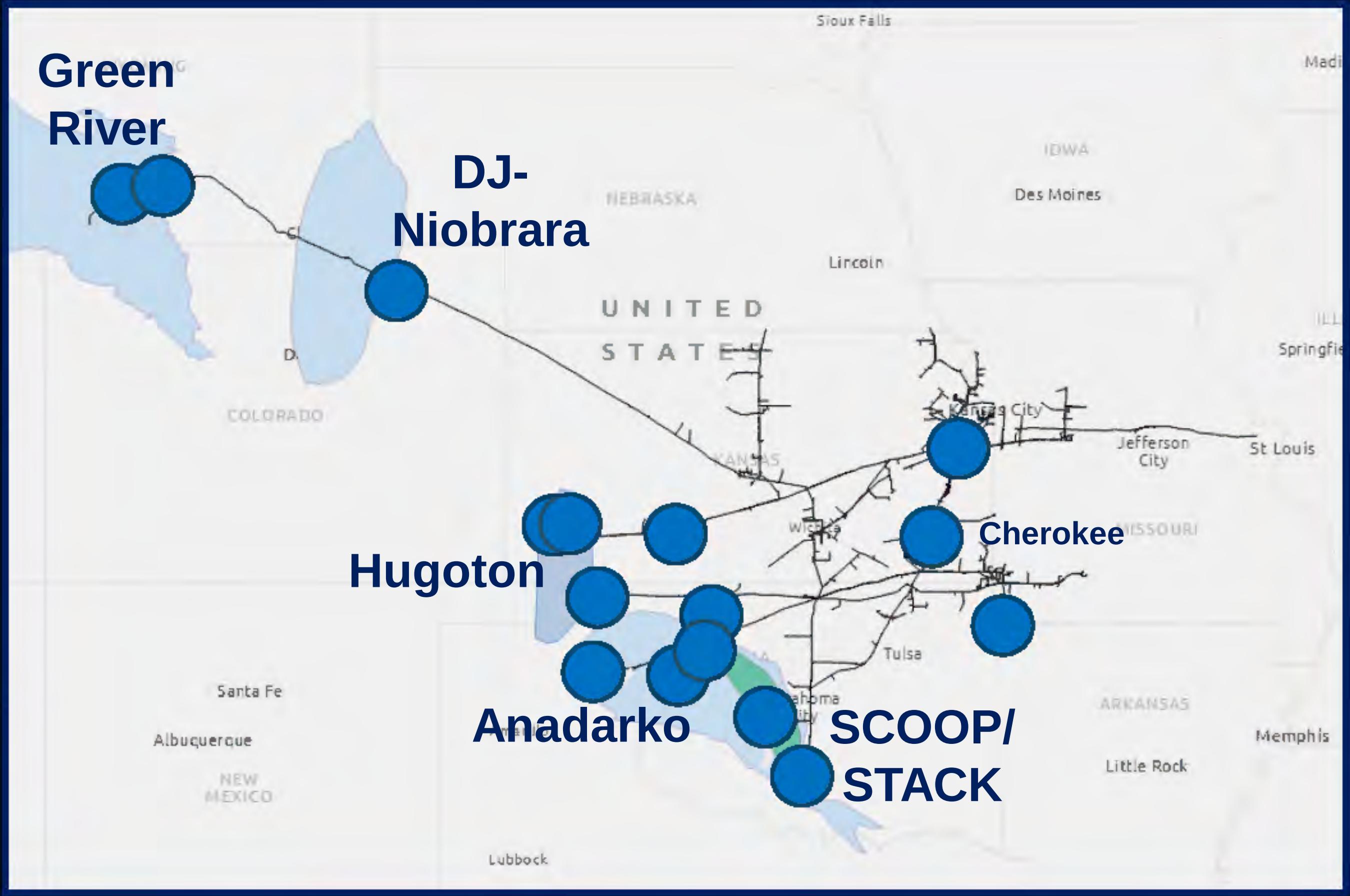
Direct	Jayhawk (Grant, KS), Waynoka (Woods, OK)
Pipeline	Tallgrass Interstate (TIGT)

The Anadarko (South) Basin

Direct	Various plants (OKC to TX panhandle)
Pipeline	Transwestern (TW), OK Gas (OGT)

The Market Area

Direct	Various plants (Cherokee Basin)
Pipeline	Enable (EGT), Tallgrass (TIGT)



Additions – Last 10 years

The Rockies Green River Basin

Direct	Grasslands (DJ Basin)
Pipeline	Wyoming Interstate (WIC), Tallgrass (TIGT

The Hugoton/Anadarko Basins

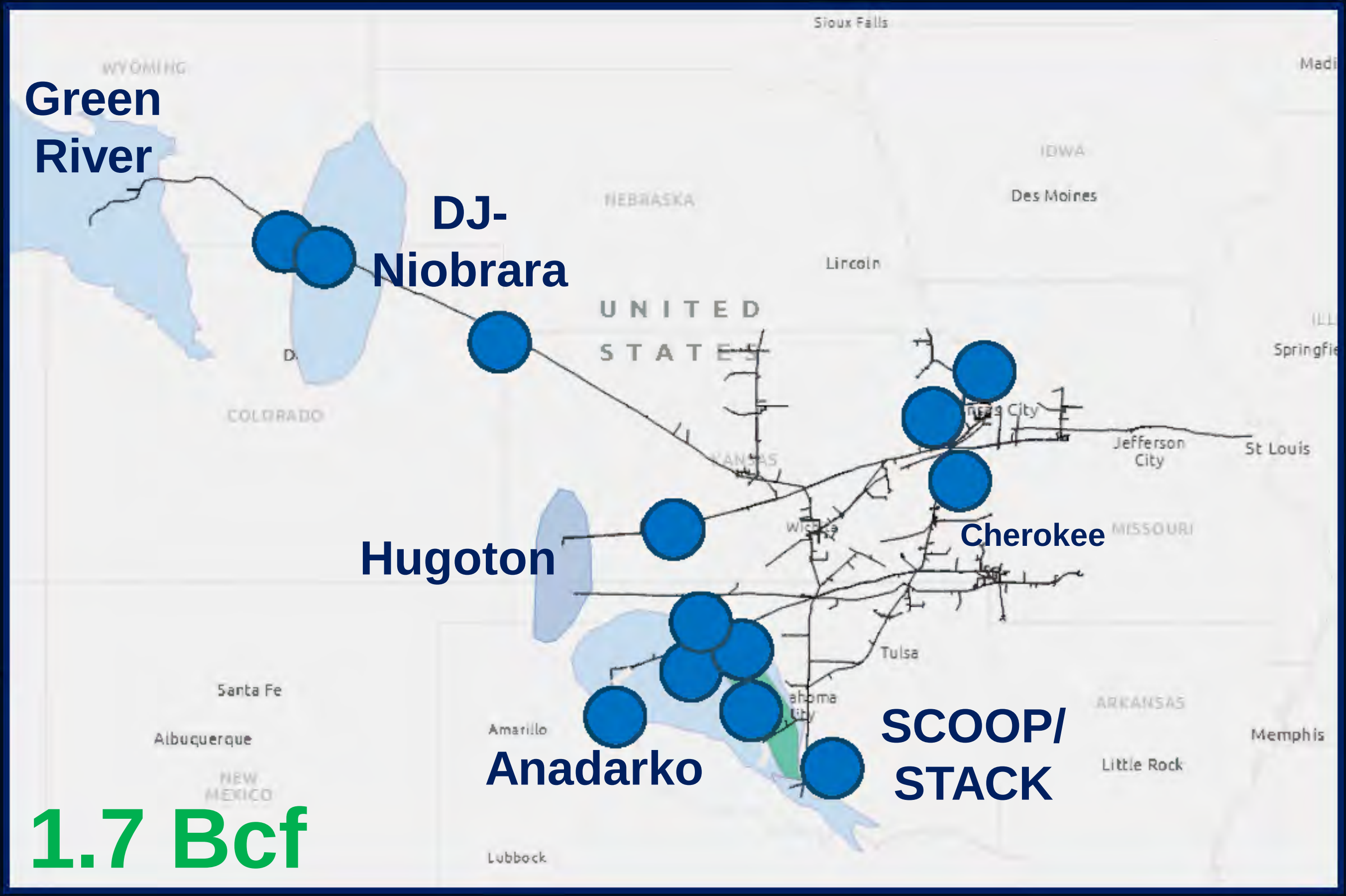
Direct	Rose Valley (Woods, OK)
Pipeline	Natural Gas Pipeline (NGPL) – Ford, KS

The SCOOP/STACK

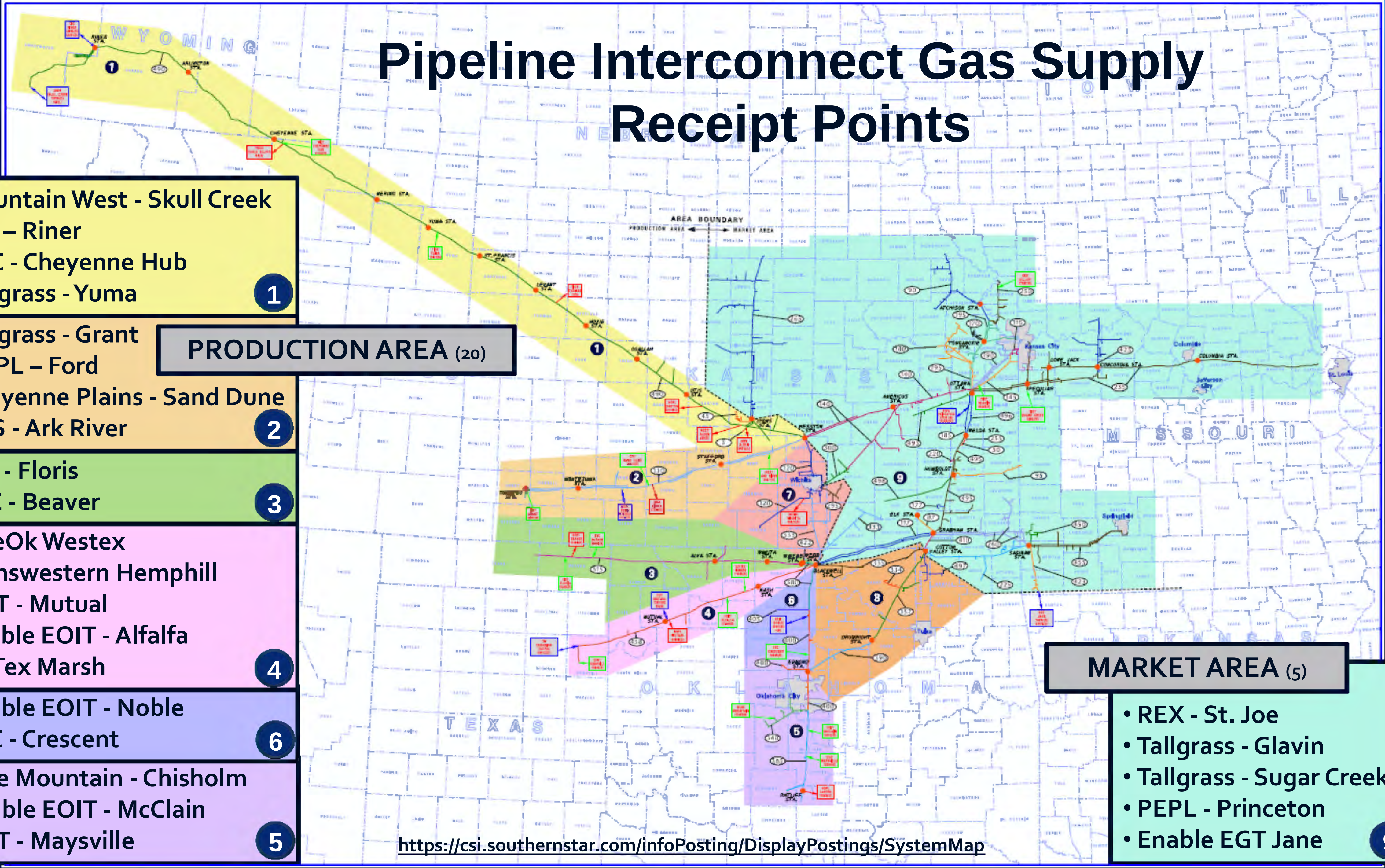
Direct	Redcliff (Dewey, OK), Blue Mountain (Grady, OK)
Pipeline	Enable (EOIT), OK Gas (OGT)

The Market Area

Direct	RNG
Pipeline	Rockies Express (REX), Panhandle Eastern (PEPL)



Pipeline Interconnect Gas Supply Receipt Points



PRODUCTION AREA (20)

- Mountain West - Skull Creek
- CIG – Riner
- WIC - Cheyenne Hub
- Tallgrass - Yuma

1

- Tallgrass - Grant
- NGPL – Ford
- Cheyenne Plains - Sand Dune
- KGS - Ark River

2

- CIG - Floris
- ETC - Beaver

3

- OneOk Westex
- Transwestern Hemphill
- OGT - Mutual
- Enable EOIT - Alfalfa
- OkTex Marsh

4

- Enable EOIT - Noble
- ETC - Crescent

6

- Blue Mountain - Chisholm
- Enable EOIT - McClain
- OGT - Maysville

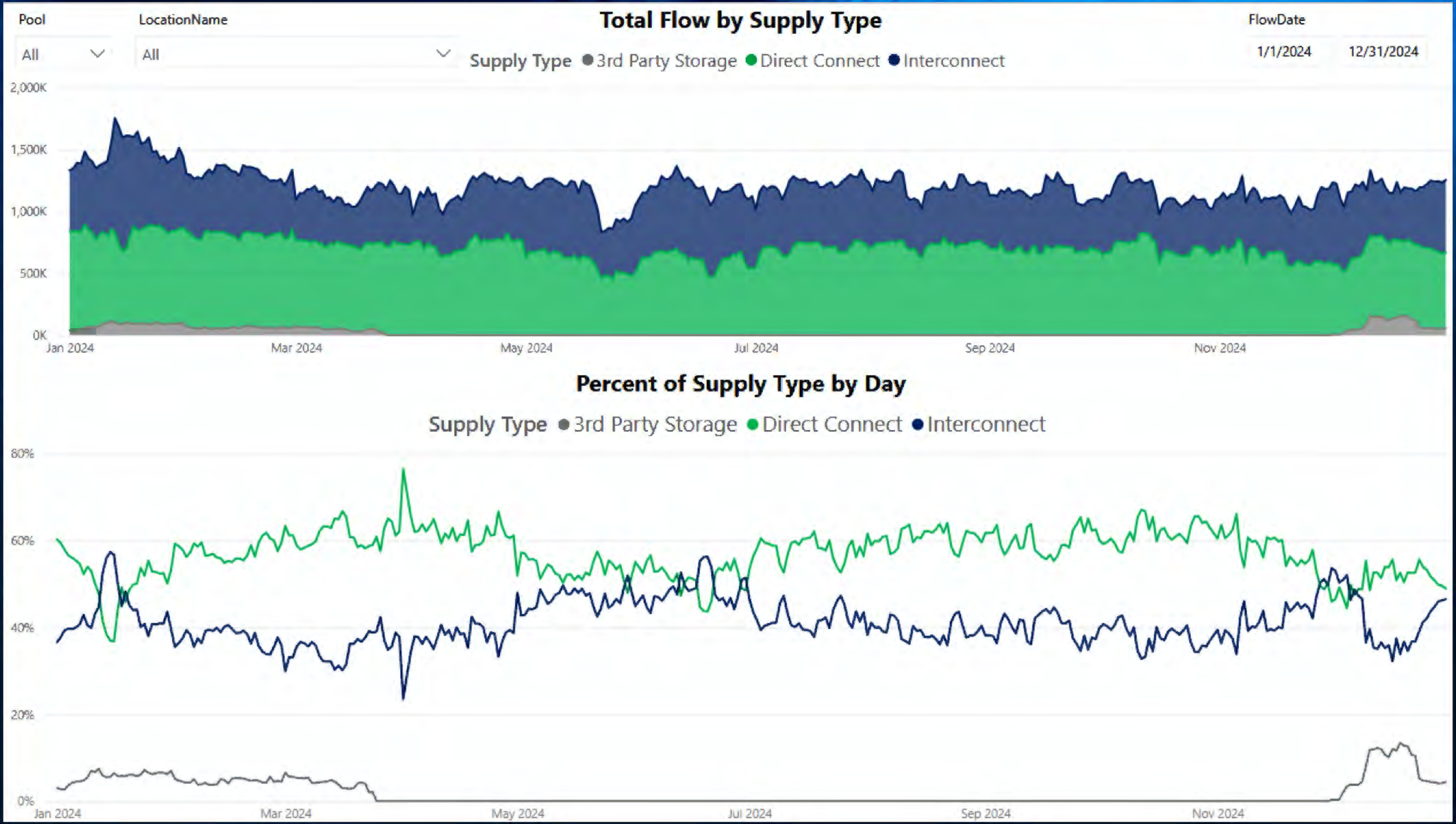
5

MARKET AREA (5)

- REX - St. Joe
- Tallgrass - Glavin
- Tallgrass - Sugar Creek
- PEPL - Princeton
- Enable EGT Jane

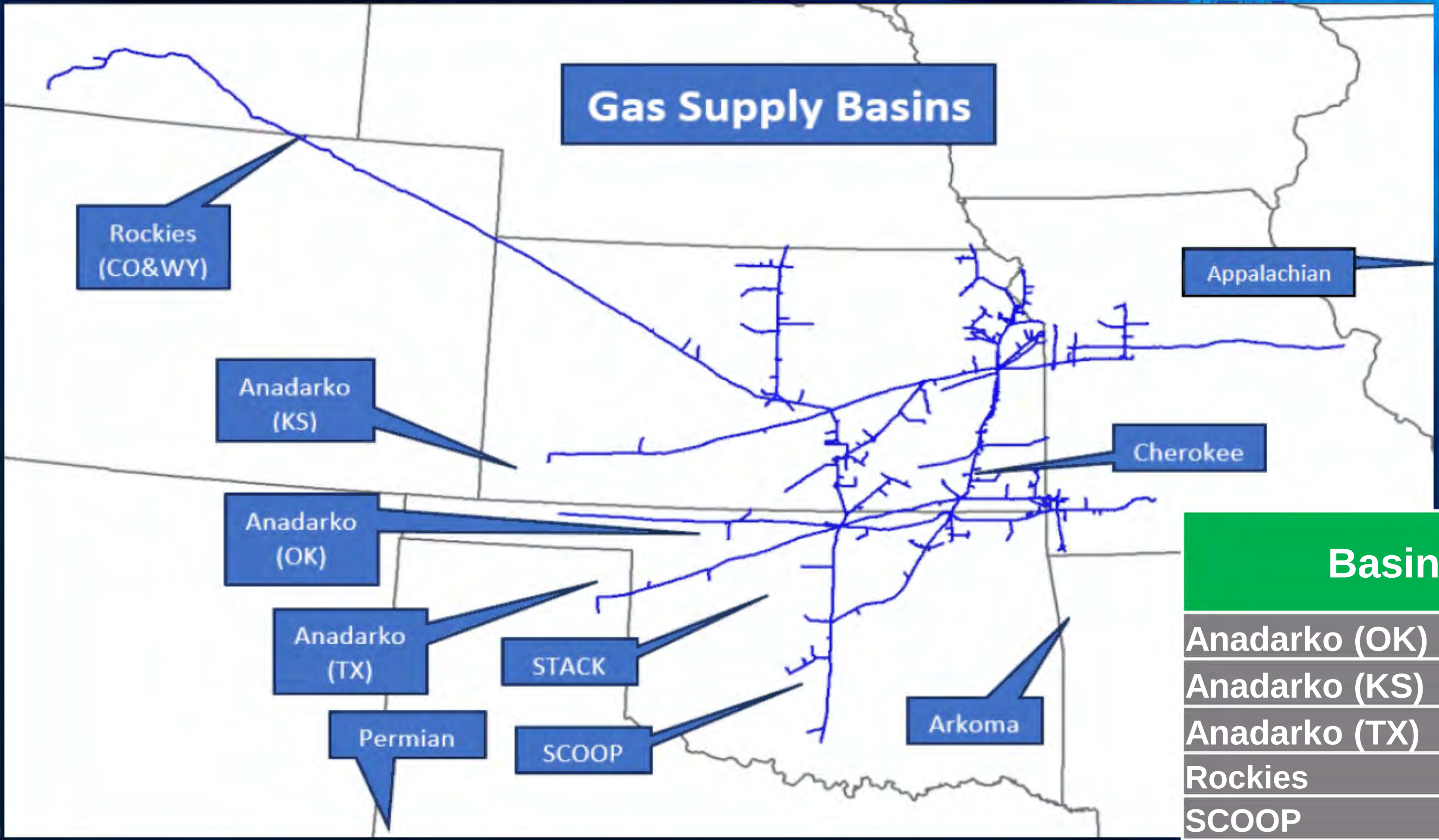
9

https://csi.southernstar.com/infoPosting/DisplayPostings/SystemMap



Pool
All
LocationName
All
Total Flow by Supply Type
Supply Type
3rd Party Storage
Direct Connect
Interconnect
FlowDate
1/1/2024
12/31/2024
2,000K
1,500K
1,000K
500K
0K
Jan 2024
Mar 2024
May 2024
Jul 2024
Sep 2024
Nov 2024
Percent of Supply Type by Day
Supply Type
3rd Party Storage
Direct Connect
Interconnect
80%
60%
40%
20%
0%
Jan 2024
Mar 2024
May 2024
Jul 2024
Sep 2024
Nov 2024

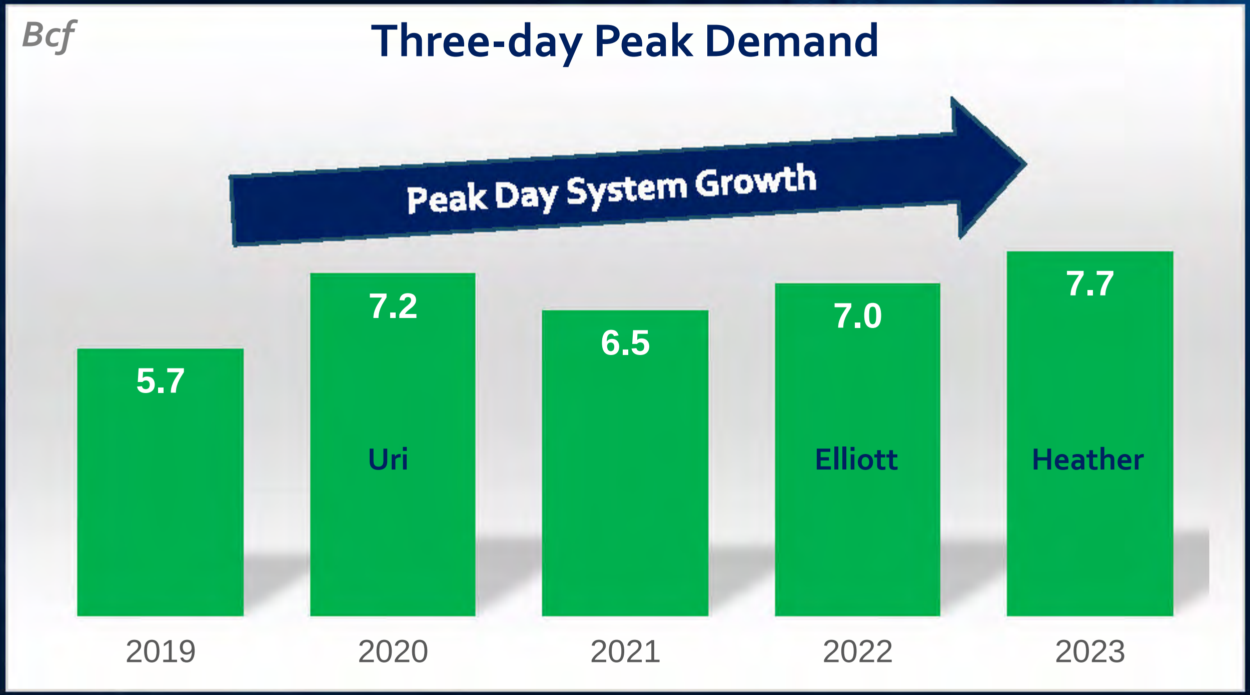
Gas Supply by Basin by Year

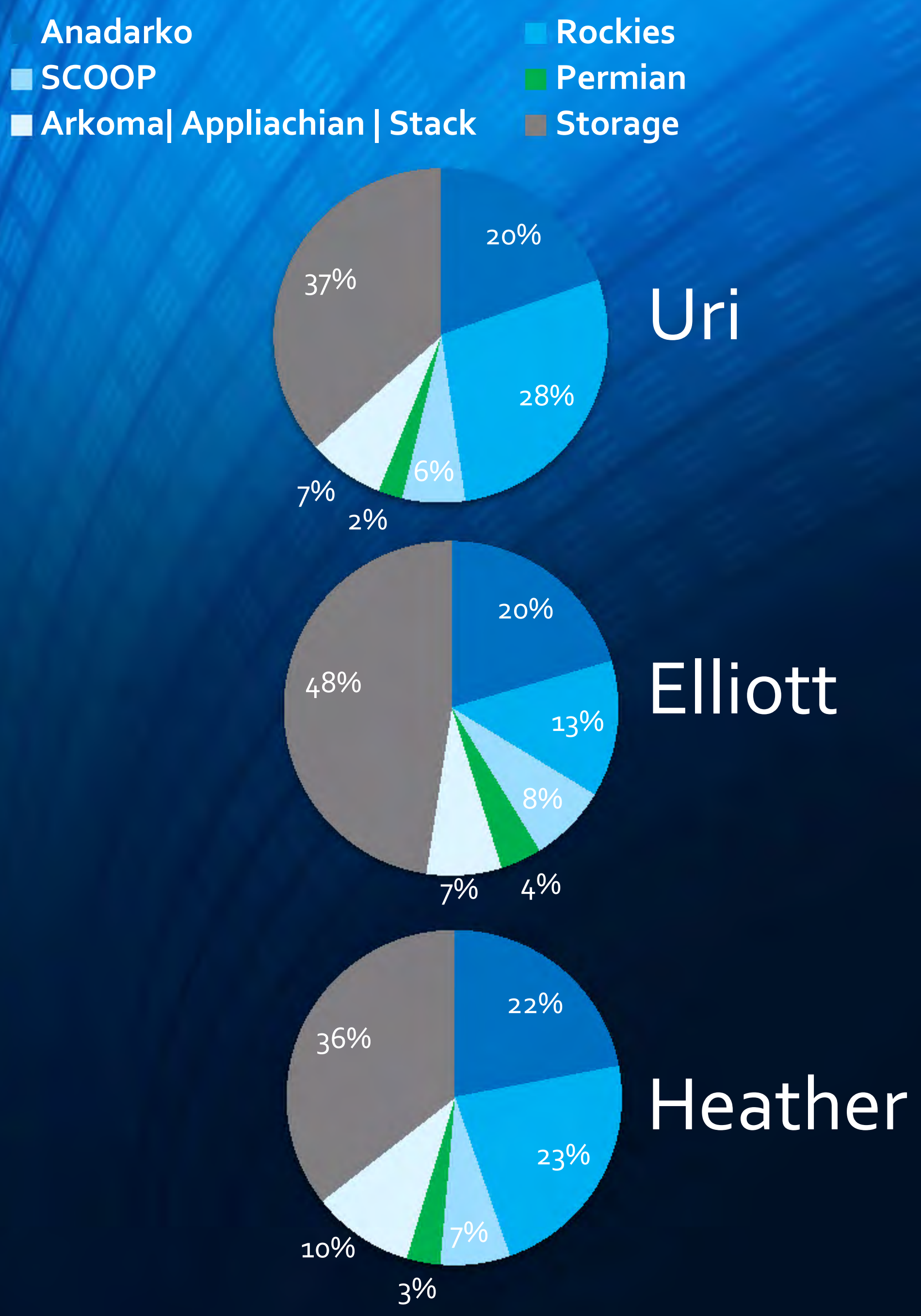


Basin	2015	2024 YTD	Change
Anadarko (OK)	37%	25%	↓
Anadarko (KS)	20%	14%	↓
Anadarko (TX)	7%	6%	↓
Rockies	17%	19%	↑
SCOOP	4%	13%	↑
Permian	0%	10%	↑
STACK	8%	5%	↓
Arkoma	1%	5%	↑
Cherokee (KS)	8%	2%	↓
Appalachian	0%	2%	↑

Peak Day Gas Supply by Basin/Year

- Storage is still very important during peak periods
  - *SSC has* ***1.3 Bcf*** *of* ***Daily Deliverability***





Future Gas Supply Opportunities

	Interconnecting Party	Location	Supply Profile	SSCGP Zone	Design Capacity (Dth/d)
1	Panhandle Eastern Pipeline (PEPL)	Sedalia, MO	MidCon	MKT	150K
2	RNG Receipts	KS, MO, OK	RNG	MKT	4K
3	Various pipes	Hugoton, KS Kiowa, KS	MidCon	PRD	250K
4	OneOK WesTex Expansion	Hemphill, TX	Permian	PRD	200K
5	Natural Gas Pipe Line (NGPL)	Ratliff City, OK	TexOK	PRD	150K
6	MIDSHIP	Ratliff City, OK	SCOOP STACK	PRD	150K
7	Colorado Facility	Keota, CO	Rockies	PRD	50K
8	Permian plants	Midland, TX Delaware, NM	Permian	PRD	1.0M
Total					**1.95M**

Staff Exhibit JTG-9

DATA DISPATCH

US power sector plans 80 GW of new fossil fuel capacity, 159 new plants

Wednesday, February 19, 2025 5:13 AM ET

By Susan Dlin, Karin Rives
Market Intelligence, Commodity Insights

Electrical transmission lines run toward a Meta datacenter in Eagle Mountain, Utah. Meta worked with Rocky Mountain Power to offset emissions from the facility's power consumption by funding renewable energy projects in the state.
Source: George Frey/AFP via Getty Images.

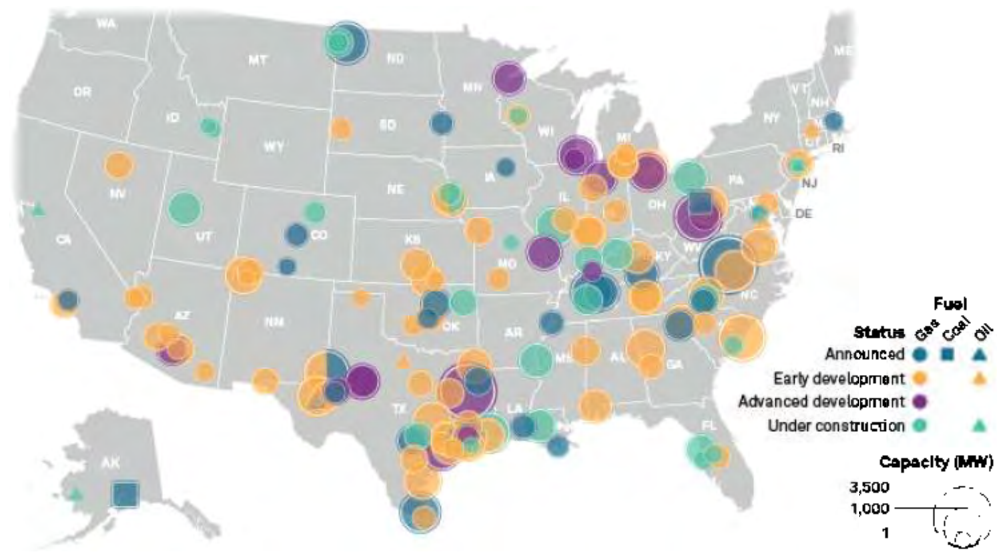
Meta's multibillion-dollar datacenter in northwestern Louisiana was heralded as a transformative economic development win for the state when it was announced in November 2024.

The power company that will service the 4 million-square-foot facility saw a promising opportunity, too: Entergy Louisiana LLC is planning to build three natural gas-fired power plants with a combined capacity of 2,263 MW to meet Meta's datacenter needs, for a total investment of $3.2 billion.

The utility's project is part of a broader trend. As of January 2025, US power providers and developers had plans to add 79.8 GW of fossil fuel-fired plant capacity — a 30% increase since April 2024, data from S&P Global Market Intelligence shows.

Natural gas-powered plants accounted for nearly all new planned capacity, and coal and oil projects called for 700 MW and 52 MW, respectively, the data showed. In all, 159 new fossil fuel-fired plants were either in development or announced.

US planned fossil fuel-fired power plants



Data compiled Jan. 30, 2025.
Map credit: Jonathan Paul Laigee.
Source: S&P Global Market Intelligence.

Natural gas comes roaring back

Utilities were steadily ramping up plans in 2024 for new fossil fuel-fired power plants to meet surging demand from datacenters, manufacturers and the electrification of appliances and cars. Even so, actual deployment of renewables and carbon-free generation continued to overshadow natural gas, coal and oil for the entire year.

New or expanded installed capacity in wind, solar, nuclear, biomass and geothermal heat made up 93% of total capacity additions in 2024, according to the Federal Energy Regulatory Commission's infrastructure update released Feb. 6. It was a record-breaking year for adding carbon-free capacity, according to Cleanview, a market research platform.

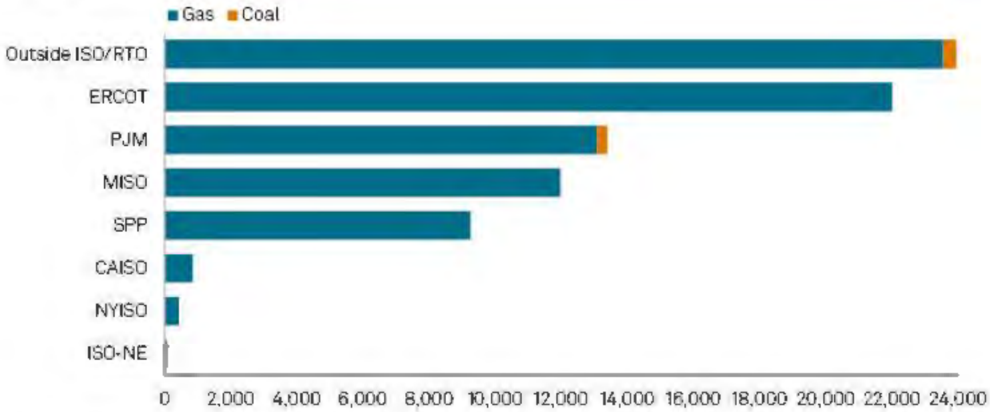
The year featured a nearly three-decade low in bringing gas-fired power plants online, said Michael Thomas, founder and CEO of Cleanview. Ambitious corporate climate commitments and new federal rules aimed at cutting emissions during the Biden administration may have dampened utilities' appetite for fossil fuel investments and contributed to the dip in new natural gas capacity.

But 2024 "may have been the calm before the storm," Thomas said.

Soaring demand for electricity is coinciding with the Trump administration's anticipated rollback of Biden-era energy and climate policies. Fossil fuel-friendly legislation is being introduced in Congress, and utilities are revising their resource plans to make less room for clean energy.

Those developments help explain why utilities are planning more natural gas plants, foreshadowing "a huge amount of new gas capacity coming online over the next few years," Thomas said.

Planned US fossil-fuel capacity by region (MW)



Data compiled Jan. 30, 2025.
Chart excludes a negligable amount of planned oil capacity.
Source: S&P Global Market Intelligence.

Solar capacity deployment will be cut by more than half by 2035, and new installed wind resources will be reduced as much as 44% if specific Clean Air Act pollution regulations are rolled back, the Rhodium Group projected in a December 2024 analysis of policy changes under the second Trump administration.

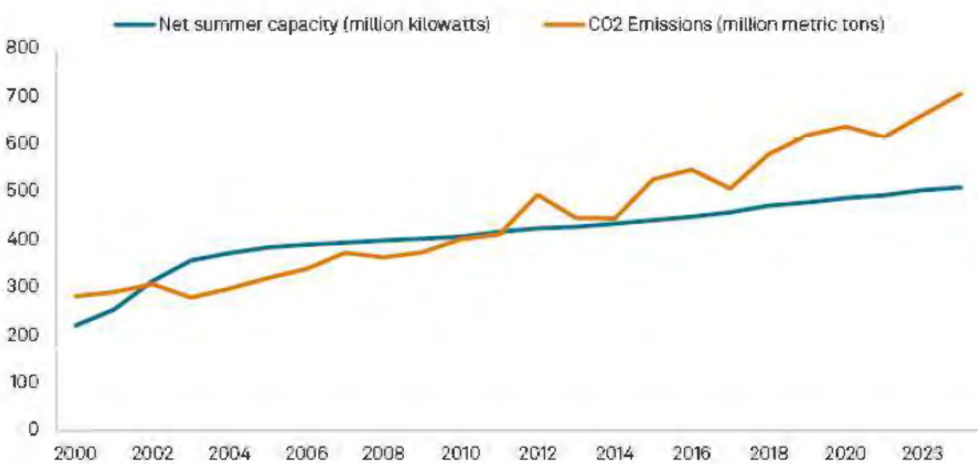
"In our modeling, gas increases to fill that gap," said Ben King, an associate director of the Rhodium Group's energy and climate practice. "But even with the repeal [of regulations] there's still some room for driving down power sector emissions."

Uncertainty proliferates the mood in the industry today, King and other analysts said. Nobody can say for certain how much power will be needed in the coming years, whether electric utilities are overbuilding or underbuilding, or when the power sector and nation as a whole will transition away from fossil fuels, if ever, analysts said.

More gas but even more clean energy

A number of US electric utilities have been updating their resource plans to include less wind and solar and to extend the life of their fossil fuel-fired power plants for the next 10 years, according to RMI, an energy research firm. The planned natural gas plant capacity will result in an 8% increase in greenhouse gas emissions between 2023 and 2035, RMI researchers said in their latest assessment of plans filed by regulated utilities during the fourth quarter of 2024.

US natural gas plant net summer capacity and emissions since 2000



Data compiled Nov. 1, 2024.
Source: US Energy Information Administration.

Even so, utility plans show deployment of renewable capacity exceeding fossil fuel capacity 3-1 by 2035, said Lauren Shwisberg, principal for RMI's electricity resource planning and virtual power plants programs.

"We're still seeing projected emissions decline by about 56% compared to 2005 with the current planned gas build-out," Shwisberg said during an interview. "That's not on track with what we'd expect to see in order to mitigate the worst impacts of climate change, but it's still a pretty significant decline in overall power sector emissions."

Entergy is one utility that continues to add clean energy generation capacity to its portfolio and is also among those that are revising climate goals.

"Achieving 50% carbon emission-free generation capacity by 2030 will be delayed as a result of overall sales growth that is greater than originally expected," Entergy spokesperson Brandon Scardigli said in an email. "We are in the process of considering how we might reset that goal."

As for Meta and its massive Louisiana datacenter, any emissions associated with powering its operations will be offset through renewable investments the technology company makes elsewhere, the companies have said.

Meta has made commitments "that provide a path" to offset 60% of the emissions from the plants by 2031, Entergy Louisiana President and CEO Phillip May said in a testimony before state regulators in October 2024.

To meet Meta's "anticipated ramp-up timeline," construction of two natural gas-powered plants adjacent to the datacenter must be completed by 2028. The third gas plant north of Baton Rouge must begin operations a year later, May told regulators. The added capacity will benefit other customers as well, Scardigli noted.

This article was published by S&P Global Market Intelligence and not by S&P Global Ratings, which is a separately managed division of S&P Global.

Spotlight
Power Evaluator

Power Evaluator is a cutting-edge valuation suite on S&P Capital IQ Pro that integrates with S&P's best-in-class asset-level data, 40,000+ machine-learning-powered nodal forecasts, and physical risk metrics to deliver reliable, lightning-fast valuations.

Built with multiple power forecasting scenarios and adjustable financial assumptions, our completely customizable valuation suite unlocks the true value of your power plant investments from start to finish.

Screen for power projects, portfolios, and companies

Build and analyze potential new power plants and portfolios

Input custom power forecasts and sensitivities

Simulate a project or portfolio sale or purchase

Track portfolio progress against net-zero goals

Image for display purposes only

S&P Global

Power Evaluator – Key Solutions

Core Segments

Renewable & Battery Developers

Utilities

Consultants

Strategic Corporates

Investment Banks

Investment Managers & Private Equity

Image for display purposes only.

Image for display purposes only.

Object Finder

Flexibility to map your target plant, portfolio, company, or any custom combination of assets

- Screen for any plant across the United States to simulate mergers, acquisitions, or divestments of plant or portfolio
- Display and shade assets using 100+ metrics from capture price to asset value to wildfire exposure
- Prepare a custom portfolio of assets for analysis - combine companies, fleets, or individual assets

Valuation Dashboard and Workbenches

Extensive forecasting, lightning-fast plant valuations

- Compare plant valuations using multiple forecasting scenarios and 48,000+ machine-learning powered nodal forecasts
- Customize analysis with 30+ adjustable financial assumptions
- Quantify the impact of physical risks on your portfolio or asset
- Benchmark your company's progress to net zero with a focus on balancing cost-effectiveness, cleanliness, and reliability

Power Evaluator – Key Solutions

Core Segments

Renewable & Battery Developers

Utilities

Consultants

Strategic Corporates

Investment Banks

Investment Managers & Private Equity

Image for display purposes only.

Prospector

Screen for new places to build power plants

- Choose from any fuel/technology type as a siting option
- Visualize any market, state, or region on our hex-mapping system, integrated with over 100 metrics including physical risk scores, weather, capacity credits, asset value, and nodal basis
- Chain metrics together to identify the single latitude/longitude that delivers the best combination of criteria for your siting strategy

Image for display purposes only.

Asset Builder

Simulate the valuation and interconnection of a prospective power plant

- Explore what are the different fuels and technologies in demand for building at your selected location
- Add your own power, renewable energy credit, ancillary, and additional pricing strips for a more robust valuation
- Simulate the interconnection to different nodal points
- Understand how the construction of an asset could bring your portfolio closer to net zero goals using the editable weightings in our True Zero Workbench

Nodal Forecasting Methodology (FastLMP)

Title
Nodal Forecasting Methodology (FastLMP)

Summary

Page Contents

Introduction

What is S&P Nodal Forecasting/FastLMP

S&P Global's proprietary nodal forecasting architecture, FastLMP, is a day ahead locational marginal price (LMP) basis forecasting methodology developed by S&P Global in a collaboration between the advanced analytics division and the North American power market forecasting team. FastLMP was developed to address the growing need of energy transition companies to quickly understand and forecast nodal pricing behavior over asset lifetimes for a large number of simultaneous development opportunities.

As of October 2023, the FastLMP architecture has been expanded to forecast hourly day-ahead LMPs at over 40,000 locations across the United States in every major ISO.

FastLMP Hypothesis

The foundational hypothesis of FastLMP is as follows:

- There is a relationship between the state of the market and the state of any node in that market.
- The relationship between node and market is unique to each node and is a non-linear function dictated by the topology of the grid in proximity to that node.
- Complex statistical and machine learning models, when given enough data, can infer and replicate this non-linear relationship without directly observing it.
- These models, when given market state forecasts from a zonal dispatch model, can produce coincident nodal pricing forecasts.

FastLMP Topolgy

The state of the market is defined by its zonal price, demand, wind generation, solar generation, and hydro generation, as well as the zonal price differentials between the primary zone where the node is located and its neighboring zones. The state of the node is defined by its locational marginal price basis relative to the zone or market price.

The topology of the grid around a zone consists of the magnitude and structure of the transmission system as well as interconnected generators and load offtakes. FastLMP does not see any of this information - it can only infer it from the node state.

FastLMP Example

Let’s take the example of a node in ERCOT North. The node is an interconnection point for a large (200 MW) wind facility and sits about a hundred miles west of Dallas-Fort Worth (DFW). The node generally has adequate rural transmission interconnection but very windy hours, particularly in the panhandle, can lead to congestion of the transmission lines bringing the power to DFW. There are no substantial local load offtakes except DFW, and there is one large (800 MW) coal generator nearby. From this information, we would expect the model to inter and replicate the following pricing behavior:

- Hours of high wind generation in ERCOT-North should produce downward pressure on LMP basis as the local wind generation begins to congest the transmission system.
- Hours of high wind generation in the panhandle push the prices negative in that zone, creating a large negative adjacency covariate. This covariate should also drive the LMP basis downward.
- Colocation with a large load offtake means demand in the zone should be strongly correlated with LMP basis at this node.
- The presence of a large ramping thermal generator should dampen the load-LMP relationship as this generator ramps up and down following demand. Often this is captured in the lagging load and price covariates.
- A large thermal generator will likely produce shoulder-season maintenance outage price spikes captured by the anomaly detection system in the FastLMP architecture.

Advantages and Disadvantages of the FastLMP Methodology

FastLMP has tremendous advantages over traditional nodal forecasting methodologies, principally because there is no human-in-the-loop calibration activity required to produce realistic pricing behavior at the node of interest. Producing realistic pricing behavior at fifteen or twenty prospective project locations using a nodal power flow model requires potentially hundreds of analyst hours calibrating outages, load offtakes, generator behavior and other variables to produce realistic pricing at the node. FastLMP has no reliance on static power flows, no sensitive or protected grid data is required to operate the model, and no horizon / forecast length limitations.

The primary caveat of the FastLMP methodology is that its ability to infer the structure or state of the pricing relationship between the node and the market is a function of:

- The amount of available data representing that state.
- The framework’s ability to detect state changes in the historical data.
- The framework’s ability to identify and strip out anomalous pricing events – typically basis spikes caused by planned and unplanned outages.

Critically, this snapshot of the market-node price relationship is static. While the state of the underlying market can evolve over time, adding more wind, load, etc. the core assumption of FastLMP is that the local grid topology that generates the nonlinear relationship between LMP basis and market state remains unchanged. Newly formed nodes, or nodes that have recently seen substantial local development or upheaval, may not have enough historical data for the model to infer the pricing relationship necessary for forecasting.

Data Used in FastLMP

Historical Data

All historical data supplied to FastLMP is sourced directly from the ISOs. Variables are day-ahead forecasts where available, and actuals when that data cannot be obtained from the ISO. This data includes:

- LMPs
- Demand
- Wind generation
- Solar generation
- Hydroelectric generation
- Zonal or settlement point prices

Calculated data from these sourced variables include:

- LMP basis – calculated by subtracting the associated day-ahead zonal price from the day-ahead LMP for the node
- Zonal price differentials

Forecasted Data

FastLMP is a computation layer designed to sit on top of a zonal long term dispatch model of the power system. The models in FastLMP are only able to produce price predictions for a node if the model is supplied with a full set of relevant market state variables for the hour. A dispatch model (Plexos, Aurora, PROMOD) provides hourly resource operations, demand, and zonal prices.

Covariate Transformations

The variables used by the FastLMP models undergo a series of transformations designed to control their behavior over long forecast periods, to coincide with FastLMP's 'transmission topology snapshot' and to improve the predictive capabilities of the model. Load is year over year scaled to a value between zero and one. All generation variables (wind, solar, hydroelectric) are scaled as a proportion of load in the current year. Adjacent zonal price deltas are calculated by subtracting the price in the primary zone. T-1 lagging covariates for load and zonal price are calculated.

FastLMP Methodology

The FastLMP architecture is fundamentally an ensemble model, with several novel components:

- A deduplication layer designed to identify colocated nodes with identical pricing behavior.
- An anomalous pricing detection methodology that uses random forest, a flexible contamination metric, and adjacent simultaneous node behavior to identify and strip outage pricing events from the time series.
- A dynamic training period methodology that allows the framework to detect state changes and discard historical pricing behavior that does not represent the current market state.
- A custom scoring mechanism that uses a weighted combination of RMSE and volatility to identify the model producing the most realistic pricing behavior.
- A stochastic layer for replicating and reinjecting anomalous outage pricing behavior into the time series.

Deduplication

Out of the 40,000+ nodes, a subset of about 15,000 nodes are chosen to represent the set. These nodes are randomly chosen from groups of nodes that are colocated and whose price patterns correlate with neighboring nodes. This is accomplished by considering node ISO, node zone, and node location (latitude-longitude). The price pattern for each node's LMP basis is then considered, where nodes have a correlation greater than 0.99 are placed into their final colocated and correlated groups.

Anomaly Detection

Prior to modelling, outliers are stripped from the data using a robust multistep methodology.

1. Over 100 timeseries features are generated from each node's LMP basis data.
2. The nearest 20 nodes are analyzed for each primary node selected during anomaly detection. The selected nodes are weighted exponentially based on their proximity to the primary node.
3. Additional timeseries features are generated for the purpose of data subsampling based on month, weekdayweekend split, nightday split, time lags, and seasonality.
4. The generated features and each nodes' LMP basis are used to cluster the nodes into outliers and not outliers.
5. An ensemble voting method is used to define the final set of outliers for each primary node. This is based on 7 subsamples where an outlier detected in 5 out of those 7 samples is designated as an outlier.

Models

The models utilized by the FastLMP architecture are:

1. **Microsoft's Light Gradient Boosting Model (LGBM)** - a gradient boosting framework that uses tree-based learning algorithms
2. **Quinlan's M5 Cubist Regression model** - decision tree model defined by a set of rules in which a tree is grown where the terminal leaves contain linear regression models. These models are based on the predictors used in previous splits. Also, there are intermediate linear models at each step of the tree.
3. **Facebook's Prophet model** - a time series modelling algorithm based on an additive model where non-linear trends are fit with seasonal components
4. **An inhouse Cluster Regression model** - the data set is split into different clusters based on the values of certain key features. A linear regression is performed for each cluster.
5. **A 12x24 mean heuristic model used for benchmarking** - this model uses an hour-month average of LMP basis

Model Performance and Selection

The above models are run in parallel for each node, but only the best model chosen during the training period is selected to produce the final forecasted results. Choosing the best model is based on two metrics, the model error based on the root meansquared error, and on how well the model can replicate the volatility in the price series. For this, we use a standard deviation ratio which is a ratio of the standard deviation of the actual price series and the predicted price series. The best model is decided on a score that signifies the result with the lowest error and a standard deviation ratio closest to one.

Related Information

Power Forecast on CIQ Pro
Power Evaluator on CIQ Pro
Power Evaluator Metric Glossary

Article Number
000043813

Power Forecast Methodology

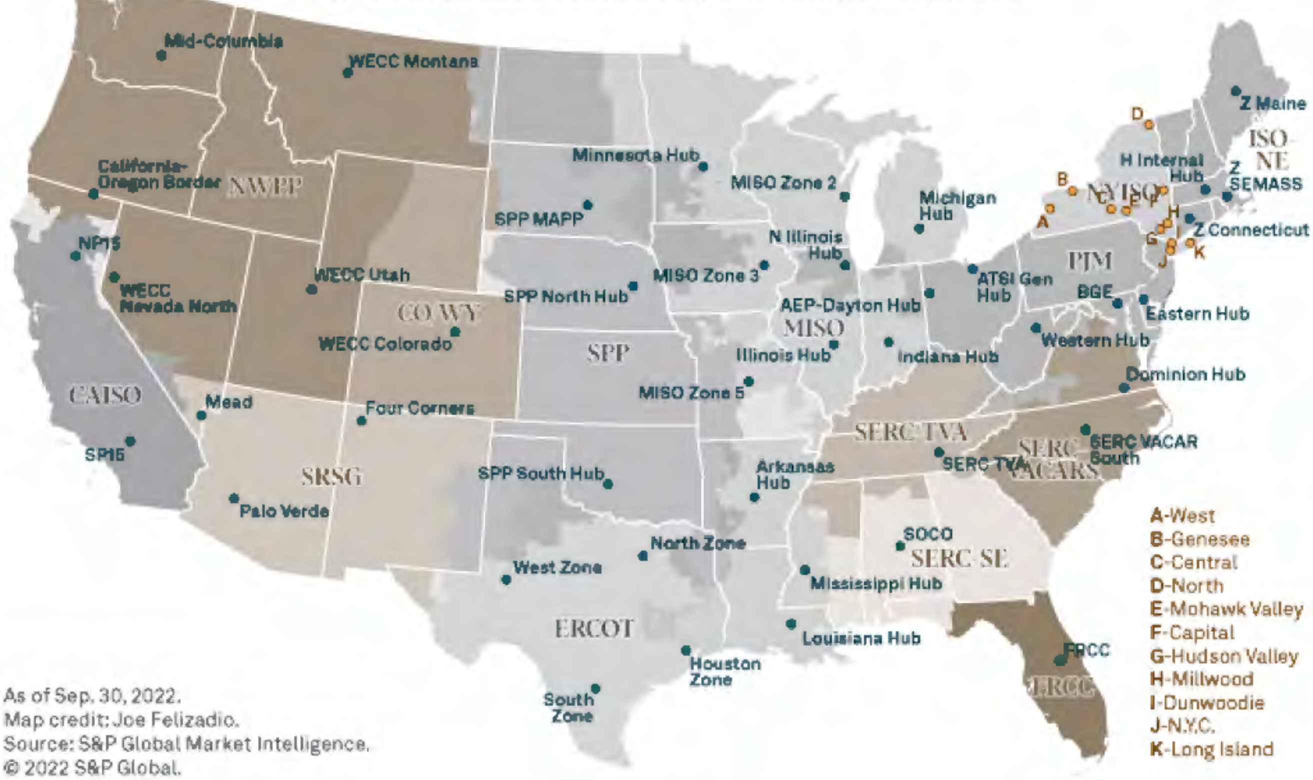
S&P Global Market Intelligence provides a quarterly forecat for key trading hubs in the United States. Subscribers may access forecasts for electricity and capacity prices, associated natural gas and coal prices, supply/demand balance, and guidance documentation.

Methodology Overview

Market Intelligence utilizes the AuroraXMP ("Aurora") tool to model several elements essential for the analysis of North American power markets. Aurora is a power market simulation tool based on an hourly dispatch engine that simulates the dispatch of power plants in a chronological, multi-zone, transmission-constrained system and is widely used for electric-market price forecasting, resource valuation and market risk analysis. Power Forecasts aim to project revenue potential for key elements of value for wholesale electricity generation, including:

- Wholesale electricity prices at key trading hubs;
- Forecasts of capacity auction results in auctions managed by Independent System Operators (ISOs), including ISO-NE, NYISO and PJM, and indicative return to capacity elsewhere; and,
- Projections of available or required generator supply, forecast demand, and associated reserve margin balances in key regions, indicating when the need for additional generation investment may occur, and what types of capacity best fit the region's investment profile.

Power Forecast covered regions and price points



As of Sep. 30, 2022.
Map credit: Joe Felizadio.
Source: S&P Global Market Intelligence.

Electricity hubs coverage list

Region	Hub/Zone	MI location name
ISO New England	Mass Hub	.H.INTERNAL_HUB
	Maine Hub	.Z.MAINE
	Conn Hub	.Z.CONNECTICUT
	SE Mass Hub	.Z.SEMASS
New York ISO	Zone A	West - A
	Zone B	Genesee - B
	Zone C	Central - C
	Zone D	North - D
	Zone E	Mohawk Valley - E
	Zone F	Capital - F
	Zone G	Hudson Valley - G
	Zone H	Millwood - H
	Zone I	Dunwoodie - I
	Zone J	N.Y.C. - J
	Zone K	Long Island - K
PJM Interconnection	Eastern Hub	EASTERN HUB
	BGE	BGE
	Western Hub	WESTERN HUB
	Dominion Hub	DOMINION HUB
	ATSI Hub	ATSI Gen Hub
	AEP-Dayton	AEP-DAYTON HUB
	Northern Illinois Hub	N ILLINOIS HUB
Midcontinent ISO	Indiana Hub	INDIANA.HUB
	Michigan Hub	MICHIGAN.HUB
	Illinois Hub	ILLINOIS.HUB
	MISO Zone 2	MISO Zone 2
	Minnesota Hub	MINN.HUB
	MISO Zone 3	MISO Zone 3
	MISO Zone 5	MISO Zone 5
	Arkansas Hub	ARKANSAS.HUB
	Louisiana Hub	LOUISIANA.HUB
	Mississippi Hub	MS.HUB
SERC-SE Subregion	Southern Company	SOCO
SERC-VACARS Subregion	VACARS	VACARS
SERC-TVA Subregion	TVA/LGE	TVA
FRCC	FRCC	FRCC
ERCOT	Houston Zone	Houston Zone
	North Zone	North Zone
	South Zone	South Zone
	West Zone	West Zone
SPP	North Hub	SPPNORTH_HUB
	SPP_MAPP	SPP_MAPP
	South Hub	SPPSOUTH_HUB
California ISO and WECC	Palo Verde	Palo Verde
	NP15	NP15
	SP15	SP15
	California-Oregon Border	California-Oregon Border
	Mid-Columbia	Mid-Columbia
	Mead	Mead
	Four Corners	Four Corners
	WECC_Colorado	Colorado
	WECC_Utah	Utah
	WECC_Montana	Montana
	WECC_NevadaNorth	Nevada

As of Sep. 30, 2022.
Source: S&P Global.

For each of the regions shown in Exhibit 1, Market Intelligence projects total supply, peak demand, reserve margin, and associated regional capacity price. Exhibit 3 lists the available regions.

Independent system operator and reliability pool regions covered

Region	Existing capacity market	Modeled capacity market
ISO New England	FCM Auction Results, three years ahead	NEPOOL "Rest of Pool"
New York ISO	Season-ahead auction	ISONY "Rest of State" (ROS), NYISO Zone J, NYISO Zone G-J, NYISO Zone K
PJM Interconnection	Base Residual Auction, three years ahead	PJM RTO, EMAAC, MAAC, ATSI, COMED
Midcontinent ISO	Bilateral capacity market with single-year manadatory auction	MISO zones 1-7, 8-10; indicative debt requirement or new peakers based on zonal capacity requirements
ERCOT	None	None; scarcity pricing estimated for Operating Reserve Demand Curve; revenues capped at debt requirement of new peakers
FRCC	Bilateral capacity market	Indicative net cash requirement or net cost of new entry
SPP	Bilateral capacity market	Indicative net cash requirement or net cost of new entry
SERC-SOCO	None	Indicative net cash requirement or net cost of new entry
SERC-VACARS	None	Indicative net cash requirement or net cost of new entry
SERC-TVA	None	Indicative net cash requirement or net cost of new entry
California ISO and WECC	Bilateral capacity market with local reliability requirements	Indicative net cash requirement or net cost of new entry
Desert Southwest	None	Indicative net cash requirement or net cost of new entry
Colorado/Wyoming	None	Indicative net cash requirement or net cost of new entry
Northwest Power Pool	None	Indicative net cash requirement or net cost of new entry
Basin	None	Indicative net cash requirement or net cost of new entry

As of Sep. 30, 2022.
Source: S&P Global.

Inputs Section

Commodities

Natural Gas – Each quarterly power forecast utilizes forward curves for natural gas that are based upon the following inputs: 1) futures prices as of the last day of the calendar quarter from CME Group for the Henry Hub through the last full calendar year published; 2) the Energy Information Administration's (EIA) most recent Annual Energy Outlook (AEO) forecast for real price growth for the Henry Hub; and, 3) Forward financial basis prices through the last full calendar year, sourced to clearing provider Amerex, as published as of the last business day of the calendar quarter. Calendar year basis quotes published by Amerex are converted to monthly basis values as described for MI Forward Gas.

Each regional gas curve is constructed as Henry Hub plus basis, with the Henry Hub made up of the CME settlement price as of the last business day of the quarter, and the CME's last full calendar year extended to the end of the required term by the EIA AEO real growth rate plus our inflation assumption. Amerex/MI Forward Gas financial basis is applied for the 84 months provided and then extrapolated forward using the last full calendar year's settlement value and adding this to the Henry Hub curve to arrive at a regional gas price.

Regional gas prices are then assigned to each gas-fired unit within the model based on proximity and deliverability. Finally, a delivered cost adder is derived for each market area and/or state to estimate the incremental cost of delivering gas from the regional market hub to a generator's burner-tip. These adders are informed by EIA 923 fuel cost filings by reporting entities as well as gas transportation tariff rates. Adders are reviewed periodically, but at a minimum on an annual basis.

Coal – The quarterly power forecast utilizes Market Intelligence's quarter-ending, fundamental coal commodity price forecast. The basic approach of the coal forecast is to take near-term forward indications of regional commodity coal prices and extrapolate that forward using projected supply and demand conditions, ultimately arriving at a long run marginal cost of production. For more information on the coal forecast, please **click here**.

Coal commodity curves are assigned to individual plants based upon historical fuel deliveries, matching their historic coal receipt specifications (coal heat content and sulfur content) to the closest matching forward curve specification. Where coal plants have shown historically material amounts of coal blending, a blended commodity coal curve is calculated based upon historic ratios of deliveries and then assigned to these plants. Finally, for certain unique grade mine-mouth coal plants in the western U.S., the EIA's AEO forecast of several these specific grades of coal are used.

Coal transportation costs are projected using Market Intelligence's coal transportation cost estimation methodology, and then escalated given underlying inflation and forward diesel prices. Market Intelligence's methodology involves estimating rates on three components: 1) fixed charges; 2) non-fuel variable charges; and, 3) fuel charges. For more information on Market Intelligence's coal transportation estimation methodology, please **click here**. An exception to our use of Market Intelligence's coal transportation methodology is associated with the unique grade, mine-mouth plants mentioned above. For those plants, Market Intelligence utilizes cost estimates from the EPA/ICF International IPM modeling.

Oil – Distillate and residual fuel oil curves are derived from quarter–ending CME settlement prices for Brent crude oil, distillate and residual oil. Where settlement price information exists for CME's New York Harbor Residual Fuel Oil 1% Sulfur and New York Harbor Heating Oil Futures contracts, this information is used to represent residual and distillate fuel oil pricing. Since these contracts do not normally extend far enough forward to cover the entire forecast period, Market Intelligence uses the CME Brent crude oil futures contract to inform oil price changes between the end of the settled contract information for residual and distillate fuel oil and the end of the Brent crude oil curve. Prices in this period of time are generated by using the recent (past 3 years) historic spreads of residual and distillate oil to Brent crude oil and applying them to the settled Brent crude oil curve. Thereafter, distillate and residual curves are derived from a Brent crude oil curve that has been extrapolated using the real growth rate from the EIA AEO forecast of Brent crude and our general inflation rate, while continuing to apply the historic spreads mentioned above.

Residual fuel oil-burning units receive the same cost for fuel throughout the model. Likewise, distillate fuel oil-burning units (including No.2, Jet Fuel and Kerosene) all receive the same distillate fuel oil cost in the model.

Nuclear – Nuclear fuel costs are estimated annually using forward quotes from CME for uranium futures and various market sources for the components of conversion and enrichment in order to arrive at a forward curve for nuclear fuel commodity costs. Further, a $1/MWh disposal cost (at a 10,000 Btu/kWh heat rate assumption) is applied to the commodity cost to arrive at the final fuel costs for nuclear units. No distinction is made for specific plant fuel costs or regional variations in fuel costs at nuclear units.

Biomass and other – Biomass units (forestry residue, agricultural residue, urban wood waste, and mill residue and energy crops) are assigned regional biomass pricing curves derived from the EPA/ICF IPM modeling of supply and demand for biomass fuels. These curves and assumptions are reviewed and updated annually.

Emissions - SO2 allowance prices are forecast by comparing the marginal cost of SO2 reduction to current and projected reduction targets, factoring in market fundamentals and drivers of traded prices. Important market fundamentals include the following: the size of the bank for previously allocated but unused SO2 allowances; the set of generating units that are candidates for cost-effective emissions reduction; and anticipated trends in SO2 emissions, given emissions-reduction plans to be put into effect (either controls or fuel switching) and displacement of coal by natural gas. Market Intelligence forecasts the balance of emissions and total allowances on an annual basis to determine the reduction target. However, as a practical matter, SO2 emission allowance markets are beset both by over-compliance to targets and policy uncertainty. Market Intelligence therefore forecasts SO2 prices by establishing a relationship between past emissions levels relative to allocated budgets and market price history and applying that relationship against future estimates of SO2 emissions indicated by long-term dispatch results. This approach drives the SO2 emission allowance price toward the marginal cost of emissions reduction technologies, but on a trajectory that may place equilibrium outside the forecast horizon. Emissions markets for SO2 over the past several years have featured surplus allowances and large discounts to emissions pricing due to superseding regulations and displacement or retirement of coal plants.

Market Intelligence uses a similar methodology to forecast NOx prices as that applied to SO2. While eastern regional NOx markets are not as heavily discounted as for SO2, many of the same market drivers apply as discussed above. Market Intelligence therefore forecasts NOx prices by establishing a relationship between past emissions levels relative to allocated budgets and market price history and applying that relationship against future estimates of NOx emissions indicated by long-term dispatch results. Like the SO2 cap and trade program, emissions markets for NOx have featured surplus allowances and large discounts to emissions pricing due to superseding regulations and displacement or retirement of coal plants. EPA's most recent NOx program CSAPR Group 3, includes more stringent caps in affected states and limited banking of surplus allowances. These updated rules have resulted in higher prices for NOx emissions allowances in affected states than seen in previous NOx cap and trade programs.

For CO2, Market Intelligence projects pricing for the Regional Greenhouse Gas Initiative (RGGI) states and the California cap and trade program (CACO2). With respect to RGGI, Market Intelligence uses near-term auction results and market indications to inform the first few years (1-3 years typically) of the forward curve. After this initial period, Market Intelligence uses recent long-term energy runs to inform our expectations of future electric emissions of CO2 and compare this with our projections of the expected supply of CO2 credits to determine the excess (or deficit) supply situation. Current excess supply conditions and pricing is used to define a relationship between price and supply, which then drives our expectations of how price should change, given our supply expectations over the near term. In all forecast periods, the resulting price is bound by the price floor on the low side and cost containment reserve (CCR) trigger price on the upside. As the terms of the program are not yet defined for periods beyond 2020, Market Intelligence holds our cap and floor price escalation rates constant at 2.5% and assume that the program cap and CCR bank are held at 2020 levels.

With respect to the CACO2 program, Market Intelligence similarly uses near-term auction results and market indications to inform the first few years (1-3 years typically) of the forward curve. After the liquid period, pricing reverts to the administrative auction floor price, which starts at $10.00 in 2013 and escalates at inflation plus 5%.

Existing and Planned Generating Units – Supply

Types of Units Considered

Market Intelligence's generator database serves as the foundation of the supply side resources that we model within Aurora. Each quarter Market Intelligence reviews the base existing generator database to determine what new units have started and ceased operations and what characteristics may have changed (such as rated capacity, operating status).

Market Intelligence also reviews each quarter the Market Intelligence database for new planned units that meet the criteria of either being under construction or in advanced development status (please **click this link for Market Intelligence's methodology for determining project status**). For "under construction" planned units, it is assumed that they will achieve commercial operations. New "advanced development" planned units are reviewed for their potential to achieve commercial operations, with positive perspective placed on projects that are wind or solar technologies, have secured power purchase agreements, or are being developed by vertically integrated utilities. Projects categorized by Market Intelligence's content teams as early development or announced are excluded from consideration, with the exception of those units clearing forward capacity auctions where that information exists.

Conventional fossil-fired and nuclear units are treated as either commitment or non-commitment (fully dispatchable) in the context of the Aurora model. Commitment units are required to be scheduled in advance, and are characterized by having minimum loading levels, minimum operating times and segmented heat rates. Non-commitment units are treated as being fully dispatchable and possessing uniform heat rates and a minimum run time of one hour. Nuclear, coal, gas and oil steam turbines as well as combined-cycle units are treated as commitment resources. Gas turbines, internal combustion, demand response, cogeneration units, geothermal and all technologies consuming biomass are treated as non-commitment.

Cogeneration units are looked at in a different manner than non-cogeneration units. Market Intelligence analyzed the typical operating characteristics of each cogeneration unit to determine a normal percentage of the unit's output that is available for sales to the grid. Only that portion of the unit's output that would typically be available for external sales is modeled as such. The portion that is available is treated as a must-run unit with monthly output pre-determined based on historical plant operations. Combined-cycle plants flagged by the EIA as cogenerators were reviewed to identify plants whose operations resemble a non-cogenerator. This typically occurs in cases where plants originally designed as cogeneration units have lost their original steam contracts and now operate as merchant power facilities. Once identified, these plants were then modeled as non-cogeneration plants.

Wind and solar units are treated as fixed-output resources, whereby their generation is pre-determined through a defined hourly profile throughout the year. The hourly profiles that Market Intelligence uses are based upon information derived from National Renewable Energy Laboratory (NREL) datasets of simulated wind and solar profiles at locations throughout the United States.

Conventional hydroelectric are grouped into hydrologic areas with similar seasonal output conditions. Within each hydrologic grouping area, an annual total and monthly shape of expected output is set as an input. Aurora then schedules hydroelectric units to meet the input monthly energy total, consistent with the load pattern within that month.

Demand response units are treated as fixed cost, non-commitment units available for dispatch when the price of energy exceeds its cost. Their capability is determined by the amount of demand response that has either cleared in forward auction markets such as PJM and ISONE, or what is assumed to be available to the region in the latest Reliability Assessment report published by the North American Electric Reliability Council ("NERC ES&D"). Following the known portion of either of these sources, demand response's capability is assumed to remain constant thereafter.

Pumped storage units are modeled as energy storage facilities, with a pre-defined MWh storage capability (reservoir) and efficiency of filling the reservoir (energy cost to pumping). Market Intelligence looked at various market sources as well as reported generation information to set specific facility efficiencies. Aurora sets its pumped storage charge/generate schedules with a goal of optimizing energy margins for the facility.

Municipal solid waste, landfill gas and biomass waste facilities are modeled as non-commitment units and assigned a fuel cost of zero. These facilities are limited in their total output to the regional historic output of similar facilities, to prevent their collective overproduction.

Unit-level Operating Inputs

Operational data for utility and non-utility generators was compiled from a number of sources utilizing Market Intelligence's existing database of information for most inputs. This information is ultimately sourced from EIA Form 411, EIA Form 860, FERC Form 1, EIA Form 923, EPA CEMS data, and ISO-sourced resource databases. The data are complemented by Market Intelligence's primary research. Below is a summary of unit-level data used to populate the Aurora model.

Unit Fuel and Technology Designations - Units are assigned specific fuel and technology types based on latest-available EIA-923 fuel burn data as well information reported on the annual EIA-860. Known future conversions to alternate fuel sources are modeled where applicable based on primary research as well as the Market Intelligence database of future fuel conversions. For coal-burning units, generators are assigned to specific coal specifications based on reported source and quality of fuel reported on the EIA-923 filings or assigned default values based on location if no EIA-923 data is available. Market Intelligence maps each generating unit that reports using natural gas to its most appropriate physical trading hub that had liquidity in forward swaps markets. To determine appropriate trading hubs assigned to natural gas units, Market Intelligence groups units by a combination of geography and regional pipeline access assigning the gas trading hub for those units as the most proximate upstream hub to that pipeline system.

Capacity - Each unit is assigned a capacity value used in economic dispatch. Non-cogenerating units are given a summer and winter operating capacity based on information collected by Market Intelligence from the annual EIA-860 filing as well as ISO sources. For units and configurations in ISONE and NYISO greater than 10 MW, capacity data is sourced from reported information from the ISO where this information can be mapped directly to a unit or configuration in the Market Intelligence resource model. For generators in PJM, ISO data is used where possible for units and configurations greater than 25 MW. Cogenerating units are assigned a capacity by de-rating the comparable summer/winter operating capacity by a factor that represents the proportion of capability used for facility use. To establish the average de-rate, the amount of energy used for facility use is calculated from the EIA 923 filings for the latest five years. If reported information is not available, de-rates were assigned based on averages for units belonging to the same North American Industrial Classification System (NAICS) assignment.

Heat Rate - For purposes of assigning heat rates, non-cogenerator thermal units are broken into three categories; steam-turbine units, combined-cycle units, or peaking (cycling) units. For peaking units, a single heat rate is derived based on five years of historical data taken from annual EIA-923 fuel-burn and generation data. Where information is not available, class-averages for different fuel/technology combinations were used. For combustion turbine peaking facilities, default heat rates were determined based on whether a unit was a newer vintage (greater than 2010) and whether information on the turbine manufacturer and model is available. For units built in 2010 and beyond, and for which turbine data is available, Market Intelligence assigned heat rates based on turbine type, with heat rates for each turbine type derived from primary research. For all other combustion turbine units, default heats were derived based on an assigned age group, e.g. 2001-2005 vintage. For steam turbine units reporting EPA Continuous Emissions Monitoring System (CEMS) data, hourly generation and heat rates were considered for a five-year period. This data was used to establish typical unit minimum loading levels as well an associated heat rate at that level of operation. Similarly, heat rates were calculated for each unit based on observed heat rates when the unit was at full-load level. For steam-turbine units without reported data, average loading levels, and heat rates at maximum and minimum loading levels were assigned based on averages for each fuel type. Minimum and maximum heat rates for steam turbine units are utilized in the Aurora model to determine the unit's heat rate when at minimum and maximum loading, as well as to establish incremental heat rates used in the unit dispatch decision. For combined-cycle units, generators were aggregated into configurations which represent common dispatch of associated combustion turbine and steam turbine units. Configurations were assigned to heat rate curves based on type of configuration e.g. 2x1, 1x1 with duct burner. These heat rate curves represent heat rates at various loading levels for a generic combined cycle of that configuration. Heat rates for individual combined-cycle configurations are then scaled to the generic unit by examining historical heat rates for the associated plant and taking the ratio of the configurations fully-loaded heat rate versus the generic unit's fully-loaded heat rate set in the heat rate curves. Fully-loaded heat rates for combined cycles are derived from underlying annual average heat rates by applying a ratio between annual average gross heat rate and fully loaded heat rate reported from CEMS data, and then applying this ratio to the derived average heat rate implied by reported EIA-923 data. This allows units of a similar configuration to follow a proportionally identical heat rate curve but establishes unique average heat rate levels for each.

Operating & Maintenance Expenses – Utilities report plant-level operations and maintenance expenses on the FERC Form 1 for regulated power plants and RUS Form 12 for their RUS borrowers. This expense reporting covers approximately 40% of the U.S. generating fleet. Market Intelligence employs data analysis to estimate O&M expenses for the non-reporting fleet. This analysis generally follows two steps: 1) separation of expenses into annual fixed costs that accrue each year of operation regardless of utilization levels, and variable costs that accrue as a function of increased or decreased operation; and 2) estimation and attribution of these values to non-reporting units. O&M expenses are reported for 14 distinct cost accounts in the FERC Form 1 (and similarly for RUS12). Market Intelligence performs a correlation analysis to determine the relationship between each cost field and net generation. This analysis reviews several relationships including technology, size of units, regional location and age of units to identify high levels of correlation. The results indicate that several reported fields have a high correlation with net generation; these we have grouped as variable O&M costs driven mainly by generation technology, unit size and age of the plants. The remaining reported fields with low correlation to net generation are labeled as fixed O&M costs.

The following reported fields are considered variable costs: Coolants & Water (Nuclear), Steam Expense, Steam from Other Sources, Steam Transferred (CR), and Electric Expenses. For plants that do not report on these forms a combination of regression estimates or S&P Global Market Intelligence defaults are used. The regression formula is developed for each generation technology type (prime mover) for a rolling three-year period when given a large enough reporting sample. For some technologies we will also separate based on fuel type. Three years of data are used to yield sufficient sample sizes and/or smooth out periodic major maintenance outages, which can cause sudden costs jumps year over year. (Some reported plants may be excluded from the regression analysis due to inconsistent reporting.) The regression formula is based off several independent variables: net generation, age of plant, and operating capacity.

Note also that Market Intelligence omits the reported emissions allowance expense from variable costs, as this is captured in dispatch economics as a function of emissions rates and the market price of regional emissions markets, where appropriate. Emissions costs are reported separately.

The following reported fields are considered fixed costs: Production Expense – Operation, Supervision & Engineering, Rents, Maintenance Supervision & Engineering, Maintenance Structures, Maintenance Boiler Plant, Maintenance Electric Plant, Maintenance Miscellaneous Steam Plant, and Miscellaneous Steam Power Expenses. For plants that do not report on these forms, a combination of either regression estimates or defaults are used. The regression formula is developed for each generation technology type (prime mover) for a rolling three-year period when given a large enough reporting sample. For some technologies we will also separate based on fuel type. Three years of data are used to yield sufficient sample sizes and/or smooth out periodic major maintenance outages, which can cause sudden cost jumps year over year. (Some reported plants may be excluded from the regression analysis due to inconsistent reporting.) The regression formula is based on several independent variables: net generation, age of plant, and operating capacity.

Some classes of technology/prime mover, due to smaller sample sizes, operating characteristics and inconsistent reporting of net generation, result in class estimates of fixed and variable O&M expenses that Market Intelligence views as unreliable for forward projections. For these technology classes, the simplified 80/20 split of total reported O&M into fixed and variable O&M is applied. This limits the distortionary effects of small samples and small/variable net generation results. The classes of generation to which this secondary approach is applied include internal combustion, combustion turbines and several other small classes of generation.

In addition, for a small number of reporting power plants that have major capital leases (typically sale/leaseback arrangements), the value for this expense is reported in the "Rents" category and is omitted from the calculation of resource-specific projections of fixed O&M.

Emissions Rates - Fossil-fired generating units are assigned emissions rates in the Aurora model for emissions of SO2, NOx and CO2. For units reporting CEMS data, emissions rates are based on an average of several years of available reporting data. Existing units not reporting CEMS data are assigned default emissions rates based on fuel/technology combinations. For future generating units, emissions rates are assigned based on fuel/technology defaults of units utilizing best achievable control technologies. Existing units with planned emissions control projects are assigned future emissions rates consistent with the removal efficiencies of the associated technologies.

Forced Outage Rates – With respect to forced outage rates in most regions, Market Intelligence typically uses North American Electric Reliability Council Generator Availability Data System ("NERC GADS"), 5-year EFORd data to inform outage rates on all nuclear and fossil-fired technologies, further specified by size in most cases. In ERCOT, PJM and MISO, where Market Intelligence has become aware of publicly available information on region-specific forced outage rates, we have chosen to apply the region-specific rates. These inputs are reviewed annually.

Maintenance Methodology – Market Intelligence applies a maintenance outage methodology to nuclear, non-cogen coal, and non-cogen combined-cycle units informed by data from the NERC GADS reporting on maintenance. Market Intelligence does not apply a maintenance methodology to other types of units. For nuclear units, we apply a maintenance/refueling outage schedule based upon several years of recent history and extrapolate outages over the study horizon to match the normal frequency of outage for the unit. For both coal and combined-cycle units, Market Intelligence applies a seasonal maintenance outage de-rate to each unit's capacity to reflect scheduling such outages in non-peak energy pricing time periods. These de-rates are concentrated in the spring and fall and are adjusted regionally to reflect differences in peak periods throughout the country.

Mothballed and Out-of-Service Units – When units are categorized as being either out of service or mothballed, Market Intelligence starts with the assumption that the unit is currently and will continue to be unavailable but reviews each unit for any information about a plan or expectation to return to service. To the extent that public information exists that demonstrates a plan and/or expectation that a return is likely, Market Intelligence assumes the unit will return to service on the projected date of return. In special cases, such as the Bruce and Darlington nuclear unit refurbishments in Ontario (between now and 2031), specific out of service schedules have been created to coincide with the announced outage timing.

Online/retirement Dates – Market Intelligence's database drives the online and known retirement dates within Aurora. Online dates for planned units and announced retirement dates are continuously researched by Market Intelligence's content team and are updated within our database quarterly on our resource update. One exception that Market Intelligence makes is that we do not use the retirement dates listed in S&P Capital IQ Pro for nuclear units when those dates relate solely to their Nuclear Regulatory Commission (NRC) license expiration date.

Demand Data

Input demand in the Aurora model is specified for each power region based on three inputs which include specification of a base year annual average and peak energy, annual escalation vectors based off of load forecasts, and hourly vectors which shape load for each hour of the year. Information for various areas is typically released annually but reported at different times of the year. In an effort to be as timely as possible, Market Intelligence incorporates new demand forecast information for particular areas as that information is released.

Base Year Average and Peak Energy - For a specified base year, average energy for specific power regions comes primarily from three sources. For ISO regions, average energy is typically reported for ISO zones and is taken wherever available. For model areas which correspond directly to a particular NERC region or sub region, average energy is based on reported NERC values for net energy for load from annual Electric Supply and Demand (ES&D) filings. For areas which do not correspond to ISO zones or specific NERC regions, load data is derived for a base year by adding reported retail sales data from the annual EIA-861 data file for entities determined to belong to that area. This sales data is then scaled up by 7% to account for losses across the transmission and distribution system based on typical losses reported for the U.S. For areas in California, including sub-areas of CAISO, load data is taken from the California Energy Commissions Demand Forecast Report. Sources used for demand data are shown in the chart below along with typical data release timelines. Once average energy for a base year is established, an annual peak demand is derived by taking the historical peak to average ratio for that area based on historical hourly demand data multiplied times the average energy.

Sources and timeline for demand data

Region	Primary data source	Years covered	Typical timeline for release
ISO New England	ISO-NE CELT report	10	Annual; May
New York ISO	NYISO Goldbook	10	Annual; April
PJM Interconnection	PJM annual load forecast report	15	Annual; January
Midcontinent ISO	MISO annual MTEP report	15	Annual; fall/winter
ERCOT	ERCOT LT Peak Demand & Energy Forecast	10	Annual
SPP	SPP Integrated Transmission Plan	10	Triennial; winter
California ISO	California Energy Commission demand forecast report	10	Annual; winter
Desert Southwest	NERC ES&D, EIA 861	10	Annual; December
Southeastern	NERC ES&D, EIA 861	10	Annual; December
Northwest Power Pool	NERC ES&D, EIA 861	10	Annual; December
All other areas	NERC ES&D, EIA 861	10	Annual; December

As of Sep. 30, 2022.
Source: S&P Global.

Demand Escalation - To determine the peak and average energy for a specific area in any particular year, annual growth rates are applied to base year values. Annual growth rates typically come from the same sources used to determine base-year peak and average energy. For areas which do not correspond directly to a specific ISO zone or NERC region/sub region, annual growth rates are based on forecast growth rates for the most relevant NERC assessment area. Beyond the reporting period for each area, load growth rates are derived by calculating a compound average growth rate (CAGR) for the last 5 reported years of the forecast which is used for annual growth rates for the remainder of the Market Intelligence forecast.

Hourly Demand Shapes - Annual average energy is shaped for each year based on input average load shapes for each hour of the year for each market area. Hourly load shapes are derived based on historical actual reported load typically for an averaging period of five historical years but subject to data availability. For areas within an ISO, hourly load shapes are typically sourced from the associated ISO. For areas outside of ISO's the primary source of information used to inform historical hourly load is the FERC 714 which is reported for balancing authorities across the U.S. Market areas within the Aurora model typically correspond to particular balancing authorities, or groups of balancing authorities and so historical load shapes can typically be used directly for areas or through creating load-weighted average demand shapes from reported information for the group of balancing authorities which make up an area.

Modeling of Environmental and Other Policy Drivers

Competitive dynamics are important to understanding long-term power price formation, but policy and regulation exert an equal or perhaps greater influence depending on the region under consideration. This section describes how key policies and regulations are captured in the Market Intelligence power forecast. Market Intelligence models particular policy drivers that are determined to have a major impact on modeling results and are reasonably certain to be implemented and with program parameters well defined.

Environmental Regulation (CSAPR, GHG, other pending regulations)

CSAPR - A driver of power plant emissions is the Cross-State Air Pollution Rule (CSAPR), which administers a cap-and-trade program for states to cut power plant emissions of SO2 and NOx. Phase one emission budgets applied in 2015, while phase two budgets commenced in 2017. CSAPR sets up four trading markets including an annual NOx, seasonal NOx Group 2, seasonal NOx Group 3, SO2 Group 1, and SO2 Group 2. Annual NOx and seasonal NOx Group 2 trading faces no limitations while trading of SO2 allowances are restricted to members of the same SO2 group. Allowances can be banked and held for future compliance in the programs. While regional trading is allowed, states are subject to assurance provisions which are designed to ensure that states do not exceed specified annual emissions limits which are the sum of an annual budget plus a variability limit. If a state exceeds the annual variability limit, additional penalty allowances are required to be surrendered equal to two additional allowances for each ton emitted above and beyond the variability limit. Market Intelligence assigns generators based on CSAPR group participation and then projects future emissions levels for these groups using unit-level emissions rates to inform future CSAPR emissions pricing. Market Intelligence accounts for projected overages beyond variability limits by adding to emissions totals amounts equal to the required additional surrender of allowances. In general, Market Intelligence projects significant oversupply of CSAPR allowances even given additional surrender of penalty allowances removing much of the punitive nature of the assurance provisions. The exception to this is for seasonal NOx Group 3, first implemented in the summer of 2021. NOx Group 3 does not allow banking of unused allowances from retired generators. This rule adjustment tends to create tighter budgets and higher emissions allowance prices. For more details on Market Intelligence's emissions pricing methodology please see the commodities section.

CO2 – Market Intelligence models the two cap and trade programs currently active in the United States, the Regional Greenhouse Gas Initiative (RGGI) and California's cap and trade program. At this time, Market Intelligence does not model any aspects of EPA's proposed Clean Power Plan rule (currently suspended), but will continue to review the potential impacts of the proposed rule as it undergoes revision.

RGGI requires power generators in participating states (CT, DE, ME, MA, MD, NH, NJ, NY, PA, RI, VA and VT) to surrender allowances covering each ton of their CO2 emissions. Participating generators can secure allowances through the program's quarterly auctions or through over-the-counter trading. While oversupplied for years, the program's overall cap level was recently reset to 91 million tons for 2014, then declining 2.5% per year through 2020. While these cap reductions tend to support higher prices, a combination of inexpensive natural gas generation and coal retirements in RGGI states has pushed current and projected emissions below the annual caps. The market's design does contain a Cost Containment Reserve (CCR) mechanism, whereby a fixed amount of allowances become available to the market when prices exceed certain levels. While not a true price cap, the CCR mechanism should have price suppression impacts around their release price triggers. The program also has floor pricing mechanisms in place.

Market Intelligence estimates RGGI market pricing by looking at historic actual and the latest modeled CO2 emissions output from our most recent quarterly forecast update to determine our expectations for future program supply/demand balance. Taking recent auction results and reported secondary market trades for near-term periods and comparing those to expected demand for allowances, a trajectory for price is informed by comparing current supply and demand conditions to how they are expected to change in the future. The floor price and CCR trigger price form a hard floor and soft cap on pricing.

California's cap and trade regime is a more comprehensive program covering a much broader range of industries outside of electric generation. In the initial phase (2013-2014) electric power and industrial emissions are covered entities in the program, but in 2015 transportation fuels and natural gas are included in the program. The program's terms are much more complex than RGGI beyond the inclusion of sources not associated with power generation. Most importantly, California's program attempts to ensure that imports of electricity into the state are charged an appropriate rate for their emissions. This adds complexity to attempting to model the cost of imports from regions without carbon pricing regulations (which include all of California's immediate neighbors).

Pricing in the program is governed by both a floor price and a series of trigger prices, at which more allowances would be allocated to the program supply. To date, auction and secondary market pricing have hovered around the floor price, which began at $10.00/MT, and will be escalated at inflation + 5%. Information around existing emissions levels of current participants and future program participants' likely emissions levels is speculative at best. While we continue to monitor and refine our modeling methodology, we have set our pricing expectations at the program's floor price for our modeling time periods. Much like RGGI, the program's terms are not yet defined beyond 2020, so Market Intelligence assumes that the program continues beyond 2020 and that the cap and floor mechanisms remain, with trigger and floor pricing rising at inflation plus 5% per year.

The U.S. EPA issued its final rule entitled Carbon Pollution Emission Guidelines for Existing Stationary Sources, commonly called the Clean Power Plan, on August 3, 2015. Broadly speaking, promulgated under Section 111(d) of the Clean Air Act, the rule establishes statewide carbon dioxide emission standards for existing fossil fuel-fired electric generating units with the goal of cutting CO2 emissions by 32% as measured from a 2005 baseline by 2030. The U.S. EPA subsequently proposed repeal of the Clean Power Plan in October 2017 and proposed a replacement rule entitled Affordable Clean Energy (ACE) on August 31, 2018. The ACE rule provides incentives for states to pursue on-site efficiency improvements at coal plants, with no federal targets for emissions reductions. The comment period for ACE has closed, and the U.S. EPA may be expected to issue a final rule in the first quarter of 2019. Pending this regulatory outcome, Market Intelligence does not project a specific impact related to the ACE rule.

Renewable Energy Credit Forecasts

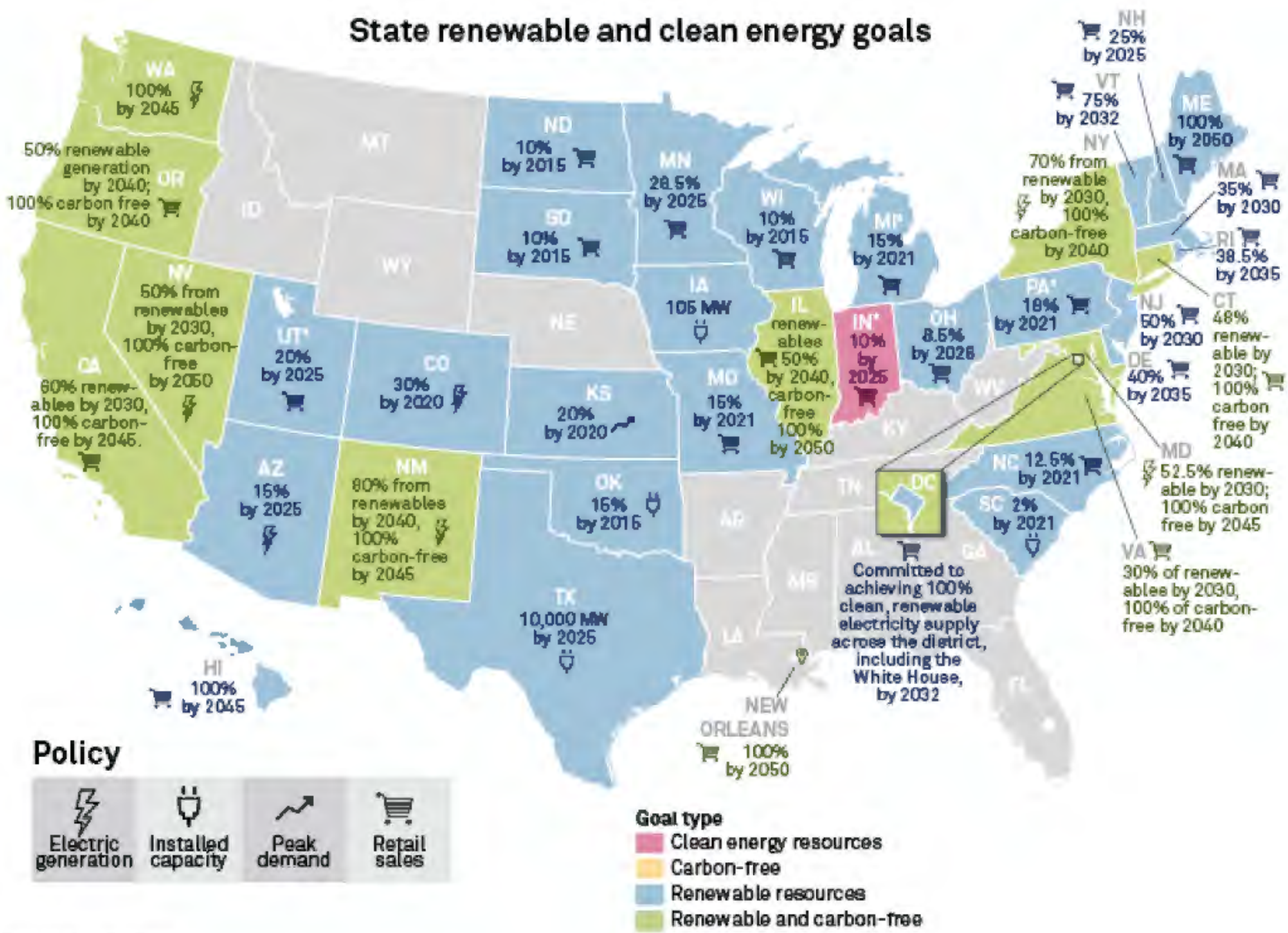
Federal incentives and Renewable Portfolio Standards (RPS)

Federal subsidies for renewable energy were renewed and extended by the Inflation Reduction Act of 2022 or IRA. The IRA represents a significant new step in U.S. energy policy by creating durable tax credits and subsidies for many zero-carbon technologies, including commercialized technology such as wind and solar generation, and emerging technologies such as storage batteries, advanced nuclear, geothermal, carbon capture and hydrogen. The IRA relies on a combination of Investment Tax Credits, Production Tax Credits, and related volumetric subsidies to encourage a broad range of investment, which phases out when electricity decarbonization benchmarks are achieved. Major incentives include the following:

- Solar – An Investment Tax Credit (ITC) equal to 30% of the installed cost of qualified solar panels or grid-scale solar projects that start construction beginning in 2023. The ITC remains available for at least 10 years, after which it phases out if electricity decarbonization benchmarks are achieved.
    - Alternatively solar projects can elect a Production Tax Credit of approximately $26/MWh for the first 10 years of their project operation.
- Onshore Wind – An Investment Tax Credit (ITC) equal to 30% of the installed cost of wind projects that start construction beginning in 2023. The ITC remains available for at least 10 years, after which it phases out if electricity decarbonization benchmarks are achieved.
    - Alternatively, wind projects can elect a Production Tax Credit of approximately $26/MWh for the first 10 years of their project operation.
- Offshore Wind – An ITC equal to 30% of the installed cost of qualified projects that start construction prior to 2026. Offshore wind projects may also elect the PTC.
- Storage – Qualified storage projects beginning construction in 2023 receive an ITC equal to 30% of installed cost, whether in stand-alone or hybrid configurations.
- Nuclear – Existing nuclear plants receive a PTC of approximately $10/MWh for 10 years, while new nuclear plant can claim this PTC for the first 10 years of operation.

Additional 'stacked' tax credits may apply for power plants using domestically sourced material, paying prevailing wages, or locating in energy-impacted communities and opportunity zones. Overall the IRA makes substantial additional tax benefits available beyond the basic tax credits.

The IRA is expected to drive significant broad-based investment in zero-carbon technologies. However, many states have Renewable Portfolio Standards or RPS that also represent avenues for investment. Market Intelligence models RPS by assessing state annual renewables requirements for forward years versus estimated generation from qualifying existing and firm planned renewables. The map below shows state renewable energy targets. Market Intelligence only models those states with mandatory RPS and explicit set-asides, not those with voluntary goals.



As of May 19, 2022.
* Includes nonrenewable alternative resources.
Indiana, Kansas, North Dakota, Oklahoma, South Carolina, South Dakota and Utah have renewable portfolio goals instead of standards.
In Minnesota, Xcel Energy is required to generate 31.5% of its retail sales from renewable resources by 2020.
In Colorado, for utilities serving more than 500,000 customers, a clean energy goal of 100% of retail sales by 2050 is in place.
Map credit: Joe Felizadio
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights

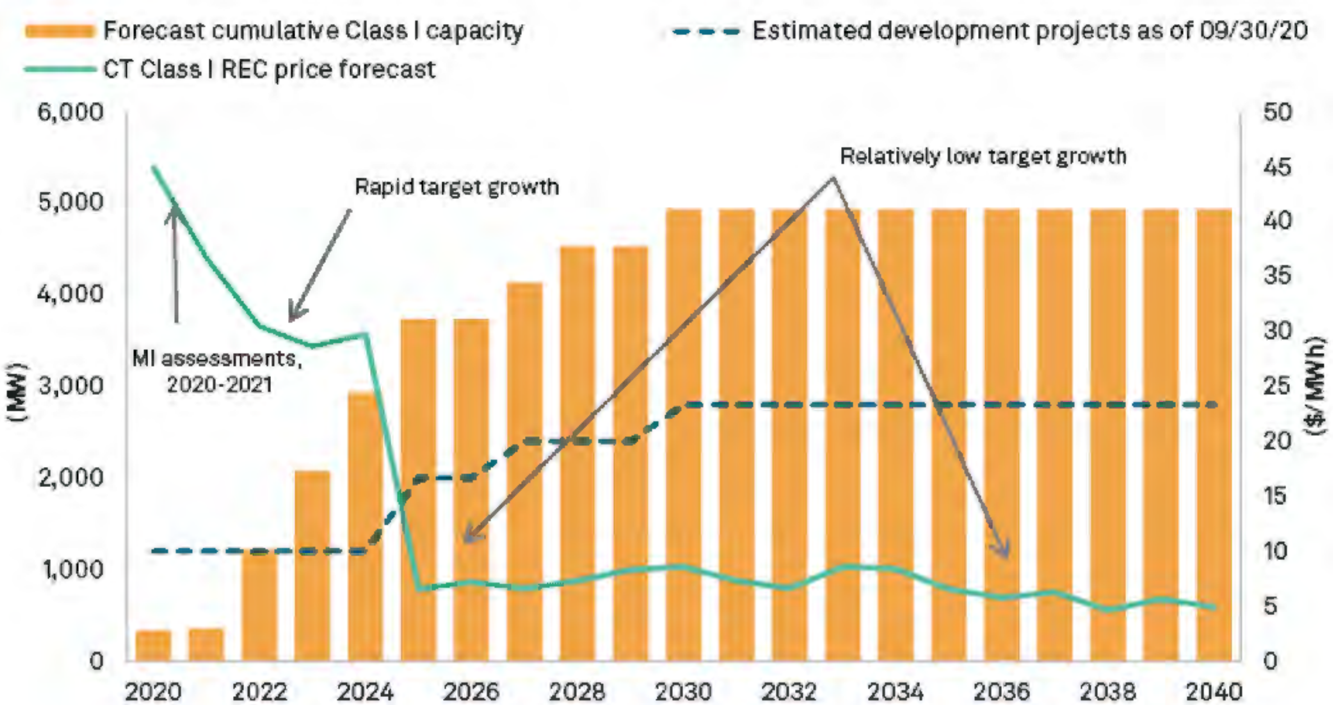
States are grouped into renewable trading markets based on trading rules with some states with limited trading capability (e.g. Michigan) modeled individually while some states are grouped together (e.g. ISO New England). For each market and each forward year, a renewable surplus/deficiency versus target is calculated, and if a market is found to be deficient, it is forced to build renewables to meet target and these resources are added into the Aurora model. This analysis is conducted each quarter to account for new firm renewable projects which have been added to the model as well as any known changes to RPS program targets. For most regions, forced renewables were assumed to be wind, but in the Southwest and California forced capacity was split between solar and wind capacity based on the share each technology represents among existing and firmly planned renewables. Among trading regions, forced renewable capacity builds are distributed in proportion to where current and firmly planned renewables are located within that market area. This means that forced builds for a particular state's RPS are not necessarily located in the state from which the requirement is driven. In addition to the primary renewables requirements under state RPS programs, many states also have carve-out requirements which specify technology-specific minimum requirements which are typically required to be sourced in state. For these carve out requirements, Market Intelligence models technology-specific force-builds where needed which are placed within relevant areas associated with the state that drives the requirement.

Forecasts of REC value

From the foregoing discussion, Market Intelligence forecasts a relative balance of Renewable Energy Credits or RECs for each state. The beginning balance reflects the estimated target in forecast year one against all renewable generation resources identified as contributing to the target. Over the forecast, growth in electricity load and in targets drives new additions, which is reflected in the forecast of modeled generation. MI reviews the outputs of the quarterly forecast to determine which markets are long or short renewable generation, and how quickly new renewable build is required relative to development activity.

To forecast REC value, MI pulls in the Market Intelligence REC assessments as of the close of each quarter to begin the curve. Typically, pricing indications cover the balance of the current year and the prompt year. Most of the forecast curve is estimated from forecast revenue requirements of renewable generation contributing to each mandatory REC market. MI estimates a revenue requirement to meet minimum debt service requirements on the annualized costs of new renewable projects as a lower bound, and a revenue requirement to meet full annualized capital costs as an upper bound. In MI's forecast approach, prices will tend to trend higher as RPS targets accelerate, and ease as ultimate targets are reached, requiring relatively few capacity additions in future years.

Connecticut Class I REC price forecast, 2020-2040



As of Sep. 30, 2020.
Source: S&P Global Market Intelligence.

Other elements influencing REC prices in each state include relative projected growth in wholesale electricity prices, emissions prices, and the ability to transact RECs across multiple states as with states in PJM or the New England ISO.

Forecasts of REC value – National voluntary markets

Market Intelligence expanded its coverage of Renewable Energy Credit markets to include voluntary REC instruments beginning in 2022. Commodity Insights produces a long-term forecast of these instruments beginning with its Q1 2022 release as of March 31, 2022. The forecast covers two instruments currently assessed: the Green E National Solar REC, and the Green E National Wind REC.

For its forecast of these national voluntary markets, Commodity Insights does not estimate supply and demand balances as with compliance markets discussed above. Commodity Insights instead assumes voluntary RECs are generally available in surplus for purposes of rounding out voluntary renewable targets. For all wind and solar projects identified in the Market Intelligence Power Forecast, Commodity Insights estimates a revenue requirement to meet minimum debt service requirements for merchant/uncontracted generation, based on the annualized costs of that cohort of renewable projects. Green E REC price forecasts will therefore usually approximate the 'low' price track estimated for specific compliance markets. Commodity Insights uses the forecast of national voluntary market prices as a floor price in all compliance markets, due to the ability of REC holders to offer RECs in the voluntary market if compliance market prices ease substantially.

Other Modeling Inputs and Conventions

Inflation – Market Intelligence uses a uniform inflation rate for those model aspects that require adjustment to reflect price adjustment over time. This expectation is derived from the Philadelphia Federal Reserve's consensus forecast of inflation over the long term. This input is reviewed annually.

On/off - peak Conventions – Market Intelligence's forecast pricing results reflect standard NERC conventions for pricing time periods, with the exception that NERC holidays are not modeled. The exhibit below displays the assumed on-peak hours and day of week that they apply. All hours and days outside these hours are assumed to be off-peak. EPT, CPT and PPT refer to Eastern, Central and Pacific Prevailing Time and imply that we do not attempt to model shifts between standard and daylight-savings time.

On/off peak hourly conventions/definitions

Interconnect	Days	Hours
Eastern	Monday-Friday	EPT hours ending 8-23
ERCOT	Monday-Friday	CPT hours ending 7-22
Western	Monday-Saturday	PPT hours ending 7-22

As of Sep. 30, 2022.
Source: S&P Global.

Description of Aurora Modeling Tool

Market Intelligence utilizes the Aurora modeling platform to perform energy dispatch analysis as well as long-term capacity expansion modeling to satisfy reliability requirements. Aurora is a power market simulation tool based on an hourly dispatch engine that simulates the dispatch of power plants in a chronological, multi-zone, transmission-constrained system and is widely used for electric-market price forecasting, resource valuation and market risk analysis. Aurora applies economic principles, dispatch simulation, and bidding strategies to model the relationships of supply, transportation, and demand for electric energy. It forecasts market prices and operation based on the forecasts of key fundamental drivers such as demand, fuel prices, and hydro conditions. Market Intelligence uses Aurora to forecast two components of power markets—energy payments and capacity payments. The energy component represents the price of energy on a real-time basis. The capacity payment represents the additional amount that must be paid to ensure sufficient supply is available in the market at the time of peak demand.

Electricity Price

Aurora analyzes generation dispatch and forecasts marginal electricity costs. Aurora is a sophisticated computer model that performs the functions associated with electric power production simulation programs, such as unit dispatch, maintenance scheduling, and cost accounting. In addition, Aurora identifies the economy energy transactions that result from the interaction of supply and demand for energy and calculates market-clearing prices for each market defined in the model. An integral part of the operation of the Aurora model is the specification of a topology which determines individual market areas within the U.S. and Canada as well as transmission interconnections which connect various areas and allow for economic flows of power. The topology utilized by Market Intelligence defines 140 unique market areas which are typically associated with balancing authorities or ISO zones. Individual market areas are then further assigned to larger pools for reliability purposes with pools generally associated with ISOs or NERC sub regions. A key part of the defined topology is the specification of transmission interties between market areas. Market Intelligence uses a variety of information to inform the transmission capacity between these areas including information provided by EPIS, the company which supplies the Aurora tool, information sourced from individual ISOs and NERC, company documents, transmission planning documents, as well as information from the Eastern Interconnect Planning Collaborative (EIPC). In addition to transmission capacity between regions, values for transmission losses and trading friction, or wheeling costs, are also modeled for each intertie based on the combination of sources previously listed as well as a calibration process which sets friction costs at levels consistent with replicating observed historical flow between regions. Additionally, Market Intelligence sets transmission limits for groups of areas to other groups of areas where such information is available. As an example, a joint transmission limit may be specified which dictates how much power can simultaneously be transferred from all PJM areas to all NYISO areas in a single hour.

Aurora assumes that each generator attempts to maximize its "gains," which are the sum of its profits on sales and savings on purchases. The objective of Aurora is to maximize gains across all companies in the interconnected system, within the constraints of supply and demand. To minimize costs, a company will dispatch its lowest cost generating units first. In the bulk power market, a profit-maximizing company will produce energy if its incremental costs of production are less than the additional revenues obtained from the sale of that energy. Thus, if it can sell energy externally for more than its incremental cost of production, the company will continue to produce after its own load needs have been met. On the other hand, if the company can buy the energy it needs to meet its load for less than the cost of its own generation, the company maximizes profit by making the purchase. This is true whether the market is regulated or competitive. If a company can sell power at a price higher than its generating costs, choosing to sell will increase profits. If a company can buy power for less than its generating costs, then buying power and curtailing its own generation will increase profits.

Aurora's operation can be characterized in three phases. In the first phase, Aurora's look-ahead logic builds cost-based price predictions for the upcoming week based on hourly loads. This determines the initial commitment schedule for units subject to operational constraints (for example, baseload and cycling units). In the next phase, Aurora simulates each defined market area independently, dispatching the resources in a market area to meet its native load for the hour. In the third phase, Aurora identifies all the transactions between market areas that would be economically advantageous given the incremental generation costs in the market areas, the transmission costs, and constraints between market areas. Finally, the model goes back and adjusts the first-phase generation dispatch to reflect the economic transactions between areas. Aurora then determines for each market the market clearing price consistent with the transactions identified in the third phase.

Market Intelligence drives Aurora using data from the Market Intelligence databases. These include historical load and cost data; operating data for existing units and other key market data derived from various sources; and the progress of announced firm power projects, which is used to generate Market Intelligence's list of expected capacity additions for each region as described earlier.

Capacity Expansion and Output Description

Resource Adequacy Constructs –Taken at its simplest, resource adequacy means having enough supply-side resources available to meet electric demand at its peak, while allowing for the potential non-performance of generators due to normal inability to perform. Markets in the U.S. have taken various approaches to address the issue of resource adequacy as they have evolved over time. When most markets were closed to generation competition and all load was served by vertically integrated utilities, the responsibility for resource adequacy fell to the incumbent utility and enforced by state regulatory commissions. That entity had an obligation to serve its customers reliably, and therefore a right to receive compensation for prudently incurred costs to provide that reliability.

As markets for generation expanded to include non-utility generators in the 1980's and 90's and after, the obligation to serve customer load became less clear as utilities had less control from whom they were buying their power. Various market constructs for the value of reliable supply of capacity therefore have evolved over time to place a value on the somewhat intangible value of reliability. In previously established electric market pools such as the Pennsylvania, New Jersey, Maryland (PJM), New England Power Pool (now ISONE) and New York Power Pool (now NYISO), reliability fell to states, and was enforced therein. NERC maintained long-term planning standards, and participants generally adhered to their standards. As some retail markets de-regulated in the 1990s and after states and pools had less direct regulatory control over participants, and the requirement for maintaining adequate supply resources began to be enforced by pools and later Independent System Operators (ISOs).

Today, the U.S. has a patchwork of structures to provide resource adequacy, with the Northeastern, Mid-Atlantic and Midcontinent ISOs providing market-based solutions to pricing capacity value, while the rest of the nation either remains rate-of-return regulated or rejects the notion of capacity payments outright (i.e., ERCOT). PJM, NYISO and ISONE employ a "demand curve" structure, whereby pricing is defined by a supply/demand intersection, while the Midcontinent ISO (MISO) currently employs an auction in which supply offers are cleared against a fixed demand amount. California has a requirement to show adequate resource capability, with local requirement considerations in congested areas, while ERCOT is still figuring out how it wants to proceed but has enacted a scarcity pricing regime that attempts to pay generators for being available when market conditions are supply constrained. All the while, there are vast areas within the U.S. that remain fully regulated and without any market-based concept of resource adequacy (i.e., non-California WECC, all of SPP and non-MISO Midwest and the Southeastern U.S. not in MISO or PJM.

The Market Intelligence approach to valuing capacity in its forecast reflects regional differences in capacity market structure. The PJM, NYISO and ISO-NE markets employ a demand-curve structure which is modeled as realistically as possible by Market Intelligence in determining capacity values. For the MISO region, Market Intelligence projects indications for the value of capacity bid in primarily by regulated market participants who can expect cost-recovery for assets in their ratebase. This tends to restrict pricing results coming out of the formal MISO capacity auctions. For all other regions Market Intelligence has attempted to arrive at a uniform value of capacity in its forecast that is translatable across regions (except for ERCOT discussed below in greater detail). The exhibit below displays the regional structures assumed by Market Intelligence.

Independent system operator and reliability pool regions covered

Region	Existing capacity market	Modeled capacity market
ISO New England	FCM Auction Results, three years ahead	NEPOOL "Rest of Pool"
New York ISO	Season-ahead auction	ISONY "Rest of State" (ROS), NYISO Zone J, NYISO Zone G-J, NYISO Zone K
PJM Interconnection	Base Residual Auction, three years ahead	PJM RTO, EMAAC, MAAC, ATSI, COMED
Midcontinent ISO	Bilateral capacity market with single-year manadatory auction	MISO zones 1-7, 8-10; indicative debt requirement or new peakers based on zonal capacity requirements
ERCOT	None	None; scarcity pricing estimated for Operating Reserve Demand Curve; revenues capped at debt requirement of new peakers
FRCC	Bilateral capacity market	Indicative net cash requirement or net cost of new entry
SPP	Bilateral capacity market	Indicative net cash requirement or net cost of new entry
SERC-SOCO	None	Indicative net cash requirement or net cost of new entry
SERC-VACARS	None	Indicative net cash requirement or net cost of new entry
SERC-TVA	None	Indicative net cash requirement or net cost of new entry
California ISO and WECC	Bilateral capacity market with local reliability requirements	Indicative net cash requirement or net cost of new entry
Desert Southwest	None	Indicative net cash requirement or net cost of new entry
Colorado/Wyoming	None	Indicative net cash requirement or net cost of new entry
Northwest Power Pool	None	Indicative net cash requirement or net cost of new entry
Basin	None	Indicative net cash requirement or net cost of new entry

As of Sep. 30, 2022.
Source: S&P Global.

Regional Reserve Margin Targets – Market Intelligence uses a variety of sources of information to inform ISO and regional reserve margin targets. In some cases, ISOs publish reliability studies that specify pool-level and specific demand-area targets. The major Eastern ISO markets (ISONE, NYISO, PJM and MISO) all publish reports that detail the pool and zonal level targets for those zones that present specific reliability concerns (i.e., Boston in ISONE, NYC and Long Island in NYISO, Eastern MAAC in PJM and the coastal Northwest). Where binding and commercially significant, Market Intelligence has employed these targets. In other regions, and particularly those without ISOs, Market Intelligence utilizes NERC reference targets. The exhibit below details our current assumptions for pool-level targets for our covered regions.

Reserve margin targets

Region	Target (%)
ISO New England	14.5
New York ISO	17.0
PJM Interconnection	16.5
Midcontinent ISO	17.3
ERCOT*	17.0
SPP	14.0
California ISO	15.0
SOCO	15.0
WECC-SRSG	13.6
WECC-NWPP	19.2

As of Sep. 30, 2022.
Based on 2020 targets.
* See the ERCOT section for additional detail.
Source: S&P Global.

Model Logic and Process – Aurora's long-term model logic allows for the analysis of an optimized capacity expansion process, based upon maintaining capacity levels at reserve margin targets, while analyzing existing units for the possibility of retirement due to a lack of economic viability. At a high level, a long-term expansion run uses the following process as it continues through a user-defined number of simulations:

1. Project demands for pools/zones across the period analyzed and compare this to the user-defined set of resources for each year, taking into account known future capacity additions and retirements.
2. Energy pricing is forecast across the study horizon and NPV asset values are generated for each existing and user-defined potential new-build resource, these values are then ranked.
3. An interim capacity price is then calculated for each year based upon the "missing money" of the marginal unit required to maintain resources at the target reserve margin. Missing money, in this case means the deficit of value to the marginal unit after accounting for energy market gross margin and ongoing fixed costs. For a new generic resource, ongoing fixed costs include the capital costs of building the unit.
4. Including the interim capacity value, a subset of the most negative existing resources is selected for retirement and a subset of the most positive generic new resources is selected for inclusion in the next iteration.
5. The model then repeats steps 1-4 until one of several conditions are met. Those conditions are that either the average system price (energy + capacity) in the latest iteration compared to the prior fails to exceed the user-defined threshold percentage change, or the maximum number of iterations has been reached. Market Intelligence uses a 0.15% threshold for our long-term expansion runs.

6. The result from this process is an optimized capacity and retirement expansion plan, which is then reviewed for rationality.

Generic New-Build Resource Assumptions – Aurora allows for the analysis of a number of new resource addition options. While Market Intelligence imposes limitations on where all resources can be considered, the following are the technologies that are considered:

- Natural gas combined cycle
- Natural gas combustion turbine
- Wind turbine
- Solar photovoltaic
- Solar thermal
- Advanced nuclear
- Coal IGCC with carbon capture

The limitations that Market Intelligence places on where technologies can be considered are related to specific regional technology feasibility and political realities. The following limits are placed on review:

- Wind turbines are not considered in zones that represent mostly major urban areas, such as New York City, Philadelphia, Los Angeles and San Francisco.
- Solar thermal is only considered in the Desert Southwest and Southern California.
- Advanced nuclear is not considered in ISONE, NYISO, Eastern MAAC, California or the northwestern U.S.
- Coal IGCC with carbon capture is only considered in three locations, PJM AEP, Southern Illinois and Wyoming.

Capital Costs of Generic New Resources – Market Intelligence uses capital cost information from the EIA's Electric Market Module (EMM) region; or 2) Cost of New Entry (CONE) studies for the ISONE, NYISO and PJM for combined-cycle and combustion turbines in those markets. Market Intelligence reviews these documents as they are updated.

The table below details the currently used overnight capital cost and performance characteristic assumptions for the technologies considered:

New resource cost assumptions -- EIA Annual Energy Outlook

Technology	Capacity (MW)	Base overnight capital cost ($2021/kW)	Fixed O&M ($2021/ kW-yr)*	Variable O&M ($2021/ kW-yr)*	Heat rate (Btu/kWh)
Conventional natural gas combined cycle	620	1,201	14.76	2.67	7,050
Advanced natural gas combustion turbine	210	785	7.33	4.71	9,750
Wind turbine	100	1,411	27.57	0.00	-
Solar photovoltaic	150	1,323	15.97	0.00	-
Solar thermal	100	5,067	67.26	0.00	-
Advanced nuclear	2,234	7,029	127.35	2.48	10,453
Battery Storage	100	1,316	25.96	0.00	-
Hybrid Solar + Storage	165/100	1,747	33.67	0.00	-
Coal IGCC with carbon sequestration	520	6,599	72.83	8.45	10,700

As of Sep. 30, 2022.
Sources: S&P Global; US Energy Information Administration.

The financing assumptions used for the resource options listed above are included in the table below. Financing assumptions are differentiated by ISO or market region and are distinguished by whether the predominant builder in the market is expected to be a utility or independent power producer. Costs of debt and equity for existing market players were analyzed to get a representative sample of market-implied rates. Market Intelligence assumes that in ISONE, NYISO, PJM, ERCOT and California the representative builder is an IPP. Elsewhere, the utility assumptions are used.

Standard financing assumptions for generic annualized costs (%)

	Gas Combined Cycle		New Wind, Solar	
	IPP	Utility	IPP	Utility
Debt return	6.3	3.5	6.3	3.5
Equity return	12.0	10.0	12.0	10.0
Debt share	55.0	50.0	65.0	50.0
Equity share	45.0	50.0	35.0	50.0

As of Sep. 30, 2022.
Source: S&P Global.

The table below outlines the new-build characteristics utilized for natural gas combined-cycle and combustion turbine units in ISONE, NYISO and PJM, as well as the financing assumptions used.

ISO/RTO capital cost assumptions

Market	Technology	Capacity (MW)	Base overnight capital cost ($2012/kW)	Fixed O&M ($2012/ kW-yr)*	Variable O&M ($2012/ kW-yr)*	Heat rate (Btu/kWh)	Debt return (%)	Equity return (%)	Debt share (%)	Equity share (%)
ISO New England	NGCC	715	1,098	29.79	1.01	7,128	6.3	12.0	55	45
	NGCT	417	814	17.59	1.61	10,770	6.3	12.0	55	45
New York ISO: ROS	NGCC	311	1,380	31.26	1.00	7,396	6.3	12.0	55	45
	NGCT	209	702	11.34	1.61	10,604	6.3	12.0	55	45
NYISO G-J	NGCC	312	1,523	37.46	1.00	7,396	6.3	12.0	55	45
	NGCT	205	885	15.15	1.61	10,604	6.3	12.0	55	45
NYISO NYC	NGCC	313	1,986	50.79	1.00	7,396	6.3	12.0	55	45
	NGCT	205	1,124	21.28	1.61	10,604	6.3	12.0	55	45
PJM RTO	NGCC	651	939	33.99	0.99	7,026	6.3	12.0	55	45
	NGCT	385	763	19.08	1.65	10,296	6.3	12.0	55	45
PJM EMAAC	NGCC	668	1,038	29.52	0.99	7,028	6.3	12.0	55	45
	NGCT	396	804	15.61	1.65	10,309	6.3	12.0	55	45
PJM MAAC	NGCC	649	1,012	28.33	0.99	7,027	6.3	12.0	55	45
	NGCT	383	797	14.42	1.65	10,296	6.3	12.0	55	45

As of Sep. 30, 2022.
Source: S&P Global.

[PS1]

Capacity Output Description – Market Intelligence produces a set of capacity prices by year for display both annually and monthly, for each region except ERCOT. Each existing and new resource that corresponds with the optimized expansion/retirement plan that is produced by Aurora's long-term process is grouped by pool/zone, analyzed each year for individual profitability and ranked according to its "missing money." Missing money is defined as the operating margin after considering energy margin, fixed O&M cost, and if the unit is a generic new-build its levelized capital cost. Outside of ISONE, PJM and NYISO, the unit that defines the marginal unit is the last unit required to keep the market's reserve margin at its respective target level. In a market that has not yet built generically to keep up with its target reserve margin, this value represents the missing money of the last existing resource in the profitability ranking that is required to keep the market at its target reserve margin. Once a market has built generically (and needs new resources), the last-built, generic new-build's missing money defines the value of capacity in that market.

For the MISO region, the above approach is used, however, zonal capacity requirements, which reflect local clearing requirements established in the MISO tariff, are used to separately determine the value of capacity in specific MISO Zones. Each zone is treated as an individual pool to establish the annual zonal marginal clearing unit and associated "missing money" for the debt portion of a regulated peaking facility. This process is also repeated for all of MISO. Zones with prices lower than the pool capacity price are given the pool calculated price as long as the amount of excess capacity in the zone does not exceed export limits as established by MISO. Zones with a higher calculated capacity price receive a price based on the unique "missing money" of that zone.

For PJM, ISONE, and NYISO Market Intelligence attempts to model the regions individual capacity market structure as closely as possible. A summary of the structure and approach employed in each of these markets is shown below.

PJM - PJM currently employs a three-year-forward auction which uses a demand curve to establish a value for different levels of reliability (capacity) against the value of supply as represented by individual generator bids. Base Residual Auctions (BRA) for the three-year-forward period are held each May with participation mandatory by both load and supply.

Additionally, PJM conducts multiple incremental auctions ahead of the capacity delivery year in order to balance capacity needs not met in the Base Residual Auction or prior incremental auctions. In addition to the RTO region, zonal reliability targets are also established, with zones receiving an individual demand curve. Load serving entities may select a Fixed Resource Requirement, or FRR, option in lieu of participation in the capacity market under certain conditions. Under the FRR option, load serving entities are required to maintain a certain amount of capacity above-and-beyond load and not allowed to participate in the capacity auction for 5 years once the FRR option is initiated.

For cleared auction periods, Market Intelligence collects price data from the BRA and represents this as the price of capacity in the capacity price forecast. For periods outside of the cleared auction window, Market Intelligence projects BRA capacity prices for each forward year by calculating the intersection between the supply stack and an estimated demand curve. Demand curves are derived by taking the latest published capacity auction parameters (currently 2018/2019) and projecting these parameters forward. Information needed to derive the future demand curves includes projections of pool/zonal demand, a projection of the gross cost of new entry for a combustion turbine unit and an estimate of the annual energy and ancillary service revenues that might be available to a proxy combustion turbine unit. Market Intelligence currently projects demand curves and associated capacity prices for the RTO region as well as the EMAAC, MAAC and COMED zones. Zones will receive a price at least as high as the pool price but are also allowed to clear higher than the unconstrained RTO. Some zones have a parent structure. As an example, MAAC will receive at least the RTO price, while EMAAC receives at least the MAAC price for a particular year.

Beginning with the June 30, 2015 forecast release and for all delivery years from 2018/2019 and beyond, Market Intelligence is projecting the Capacity Performance product for all PJM capacity locations contained in the power forecast. The creation of the Capacity Performance product is part of a set of RPM changes that PJM instituted in 2015. Capacity Performance is intended to help address issues around resource availability during emergency events and is a direct result of poor generator performance during the "polar vortex" events during the winter of 2013/2014. Resources now would be subject to penalties for non-performance during declared emergency events while having nearly all excusable outages eliminated in such situations. The penalty that resources become subject to for each MWh of non-performance is its zonal net CONE for that delivery year divided by 30. In return for taking on this additional risk, resources can include in their offers a premium to cover the additional risk and expenses they incur to comply with the new standards. Over-performing resources in emergency action hours will receive a proportionate share of penalty revenue based on its over-performance relative to the sum of all over-performance.

To incorporate an estimate of the risk-bidding behavior of generating resources, Market Intelligence estimates the net exposure to a generator of failing to perform in an emergency event hour as well as the potential for over-performing in such an hour. Incorporating data about the seasonal forced outage probability of generation technologies, as well as the seasonal probability of the occurrence of an event hour, Market Intelligence estimates the net exposure to performance penalties and rewards to generators by fuel and technology type. Market Intelligence further estimates the impact of a worst in five year forced outage rate and a frequency of emergency event hours nearly twice the expected 30. Finally, for natural gas-fired generators without dual fuel capability or firm natural gas transportation, Market Intelligence assumes that backup fuel capability is procured. Together, these aspects make up the incremental risk/expense adders that Market Intelligence applies to Capacity Performance bids.

ISONE

Like PJM, ISONE utilizes a three-year-forward auction which uses a demand curve in order to establish a value for different levels of reliability (capacity) against the value of supply as represented by individual generator bids. Forward Capacity Auctions (FCA) for the three-year-forward period are held each February with participation mandatory by both load and supply. ISONE conducts multiple reconfiguration auctions (incremental auctions) ahead of the capacity delivery year to balance capacity needs not met in the FCA or reconfiguration auctions. In addition to a "Rest-of-Pool" zone, ISONE also employs a zonal capacity structure though separate demand curves for the individual zones have yet to be established. Market Intelligence therefore currently models only the "Rest-of-Pool" zone but will evaluate adding commercially relevant zones as more information is provided by the ISO.

For cleared auction periods, Market Intelligence collects price data from the FCA and represents this as the price of capacity in the capacity price forecast. For periods outside of the cleared auction window, Market Intelligence projects FCA capacity prices for each forward year by calculating the intersection between the supply stack and an estimated demand curve. Demand curves are derived by taking the latest published capacity auction parameters and projecting these parameters forward. Information needed to derive the future demand curves includes projections of pool/zonal demand, a projection of the gross cost of new entry for a representative combined cycle unit and an estimate of the annual energy and ancillary service revenues that might be available to a proxy combined-cycle unit.

NYISO

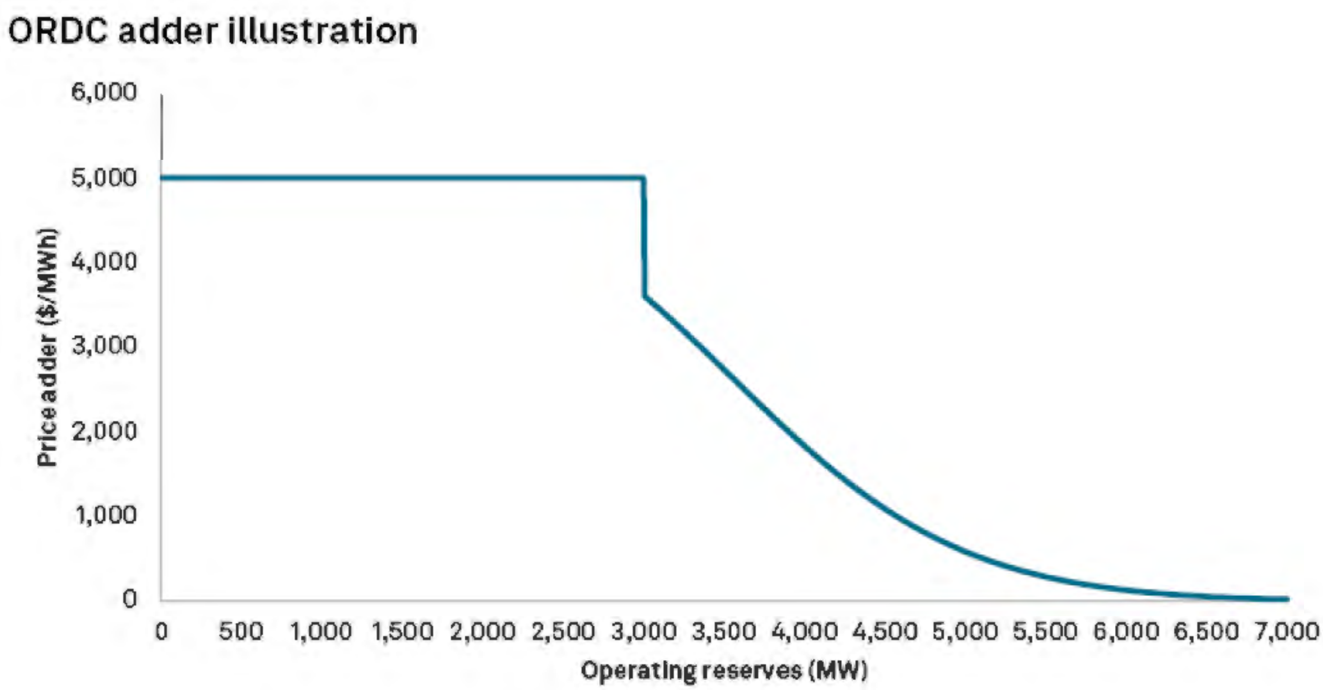
The NYISO ICAP market serves as a backstop to fulfill capacity obligations for load serving entities that have not procured capacity through self-supply or in the bi-lateral market. NYISO utilizes a strip auction for the summer and winter capability periods as well as a monthly auction which is held at least 15 days prior to the start of each month and a spot auction which is held 2-4 days prior to the start of a given month. The strip and monthly auctions are not mandatory and allow load serving entities to procure capacity on a monthly or season-ahead basis as a hedging mechanism for the mandatory spot auctions. The spot auctions utilize a downward sloping demand curve against resource bids for the New York Control Area (NYCA) to establish the intersection between the two curves and resulting clearing prices. Seasonal demand curves are established with one available for the summer capability period (May-Oct.) and another for the winter capability period (Nov.-Apr.). In addition to the NYCA, NYISO established separate demand curves and requirements for constrained zones including NYISO Zone J, NYISO Zone K and NYISO Zone G-J.

For cleared auction periods, Market Intelligence collects price data from the monthly spot auctions and represents this as the price of capacity in the capacity price forecast. If only one month or some months of a cleared auction seasonal period area available, Market Intelligence will carry this value or average of values forward for the remainder of the months in the seasonal period and pick up with the proprietary forecast beginning with the next seasonal period. For periods outside of the cleared auction window, Market Intelligence projects capacity prices for each forward seasonal period by calculating the intersection between the supply stack and an estimated demand curve for that season. All months within the same seasonal reliability period will have the same capacity price. Demand curves are derived by taking the latest published capacity auction parameters and projecting these parameters forward. Information needed to derive the future demand curves includes projections of pool/zonal demand, a projection of the gross cost of new entry for a combustion turbine unit and an estimate of the annual energy and ancillary service revenues that might be available to a proxy combustion turbine unit. Market Intelligence currently projects demand curves and associated capacity prices for the NYCA region as well as NYISO Zone J and NYISO Zone G-J. Zones will receive a price at least as high as the pool price but are also allowed to clear higher than the unconstrained NYCA. NYISO Zone J has a parent structure whereby it will receive at least the NYISO Zone G-J price, while NYISO G-J receives at least the NYCA price for a particular seasonal period.

Capacity price curve notes:

1. Market Intelligence's MISO and NYISO curves are quoted in $/kW-month of unforced capacity (UCAP), while all other locations are quoted in $/kW-month of installed capacity (ICAP).
2. Unforced capacity is a unit's capacity after adjusting for the unit's forced outage rate and can be calculated as that unit's capacity multiplied by one minus the unit's forced outage rate.
3. Several markets (MISO, NYISO and PJM as examples) pay resources for capacity on a UCAP basis, rather than an ICAP basis, which is to say that a resource receives capacity payments based upon its individual UCAP rating multiplied by the market's UCAP-based capacity price.

ERCOT Discussion – As previously mentioned, Market Intelligence does not estimate a capacity value for ERCOT because the market to date has explicitly rejected the use of a capacity auction. ERCOT has attempted to address the value of reliability by designing and implementing an administratively-imposed scarcity value adder to energy and ancillary services as the market approaches low levels of operating reserves – effectively paying resources for being available when most needed. This mechanism is known as the Operating Reserve Demand Curve (ORDC) and functions as an administrative adder paid to all resources providing energy and operating reserves when operating reserves get low. If the market is sufficiently well supplied, the ORDC pays nothing, and as the market approaches fixed operating reserve levels begins to pay the extra money, following an exponential curve, capping out at $5,000/MWh at the point of potential load shedding. The exhibit below illustrates the basic relationship between hourly operating reserves and the ORDC adder.

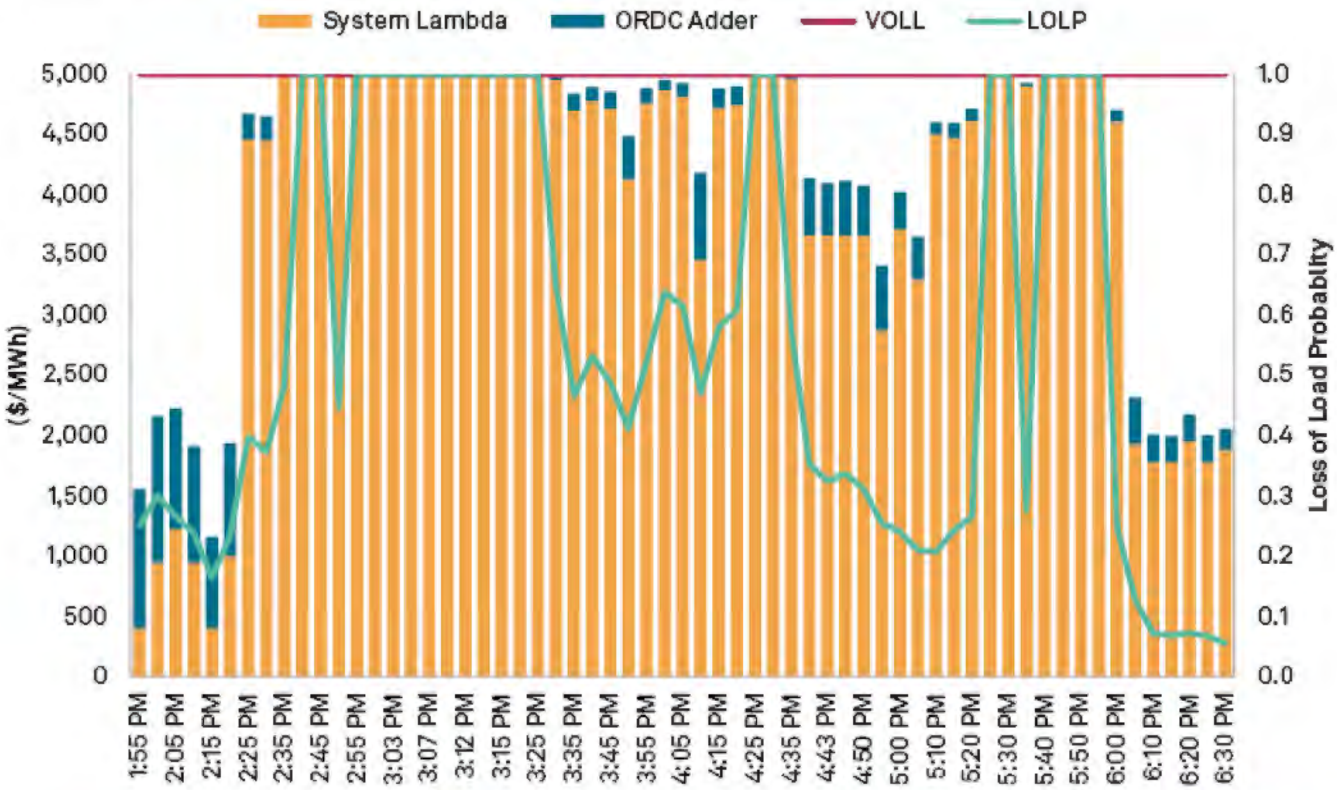


Data compiled Oct. 14, 2022.
For illustrative purposes only. Actual adder varies with system lambda and loss of load probability at the given time interval.
Sources: Electric Reliability Council of Texas, S&P Global Market Intelligence.

[PS2]

The ORDC curves that ERCOT has designed vary by time-of-day and season. The exhibit below provides a more detailed example of historical marginal electricity + ORDC pricing.

ERCOT pricing with ORDC adder - midday July 13, 2022



Example: July 13, 2022 3:40pm

VOLL = Value of lost load = $5,000

System Lambda = LMP price of energy = $4,781

LOLP = loss of load probability = .53

ORDC adder = ($5,000 – $4,781) * .53 = $116

Data compiled: Oct. 14, 2022.
ORDC = operating reserve demand curve.
Source: Electric Reliability Council of Texas, historical real-time ORDC data.

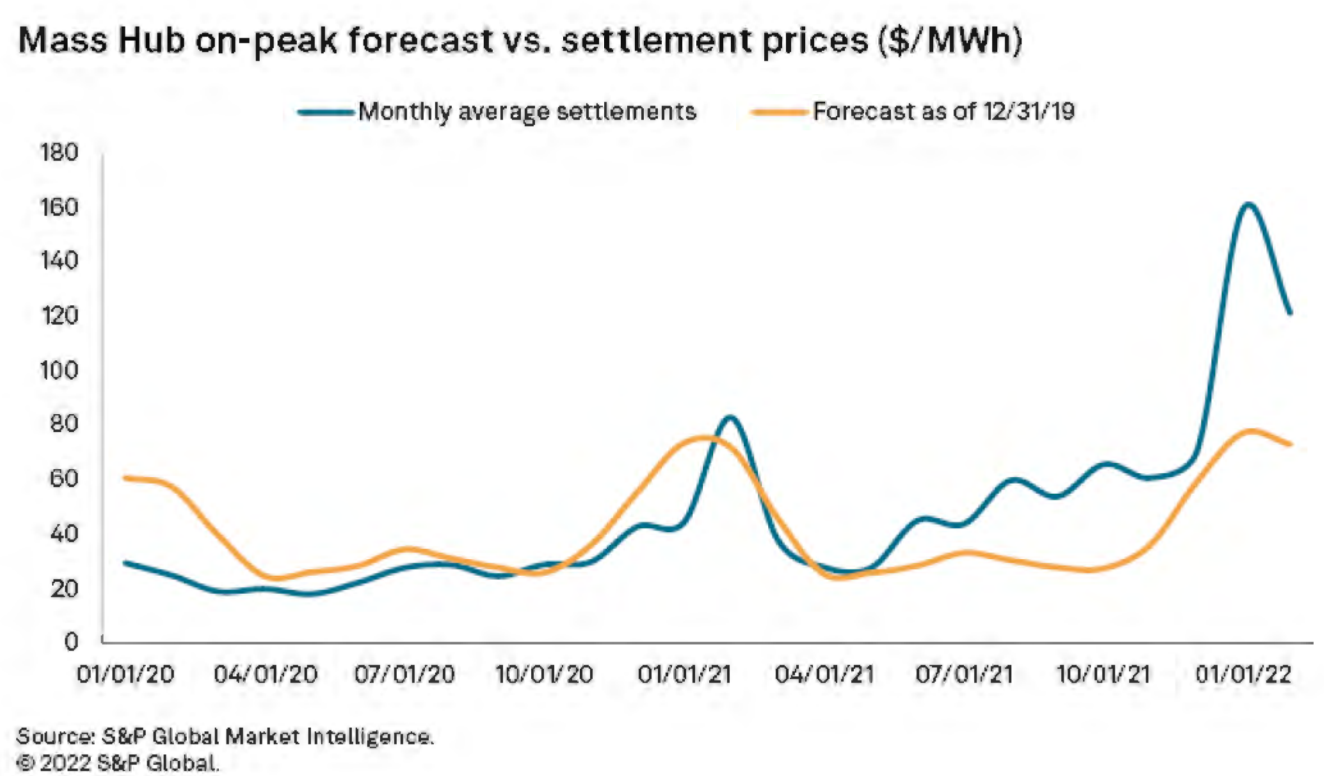
Given the market structure that has been chosen, Market Intelligence takes a modified approach to estimating a reserve margin target for ERCOT. The process involves modeling hourly the existing and known additions and retirements of the resource mix available to the market and estimating the ORDC payment available to the generic new entrant combined cycle (CC) in each year. Once the new-entrant CC can recover its missing money from the ORDC payments available to it, the target reserve margin is set for that and future years but is not imposed in prior years. Market Intelligence then runs a long-term expansion with the target reserve margin just calculated to arrive at an optimized expansion plan.

The expansion plan dataset is then run to determine the marginal energy price implied by the market, to which the expected ORDC payment is added. The expected ORDC payment to the market is defined differently depending upon whether one is building to maintain the reserve margin or prior to that point. Prior to the point at which the target reserve margin is imposed, the expected annual ORDC payment is calculated through the modeling of the hourly resource mix available to the market, and then allocated to months and on/off-peak periods based upon the average distribution over this period. After the market is forced to build to maintain reliability, the "missing money" associated with the debt portion of the last new entrant (usually either a gas-fired combustion turbine or a combined-cycle facility) defines the total value of ORDC payment and is allocated monthly based upon the expected distribution in the year determined to be the first new-build year. This reflects a view of scarcity payments that they will be limited in the long-term by regulated entities within ERCOT such as municipalities and member-owned cooperatives who remain effectively vertically integrated.

Comparison and Contextual Analysis of Model Results

Market Intelligence's approach to power forecasting is data-centered and data-verified with every attempt made to tie model inputs and outputs to reliable reported and indicative market data. Market Intelligence's power forecasting benefits from access to reliable and timely information provided by the Market Intelligence desktop platform, maintained by the content teams supporting S&P Capital IQ Pro. This information is supplemented by information collected by Market Intelligence's forecasting team specifically for forecasting efforts. While use of reported information is a strong starting place, Market Intelligence attempts to validate model outputs against reported data to assess the validity of forecast results and the reasonableness of the model inputs used.

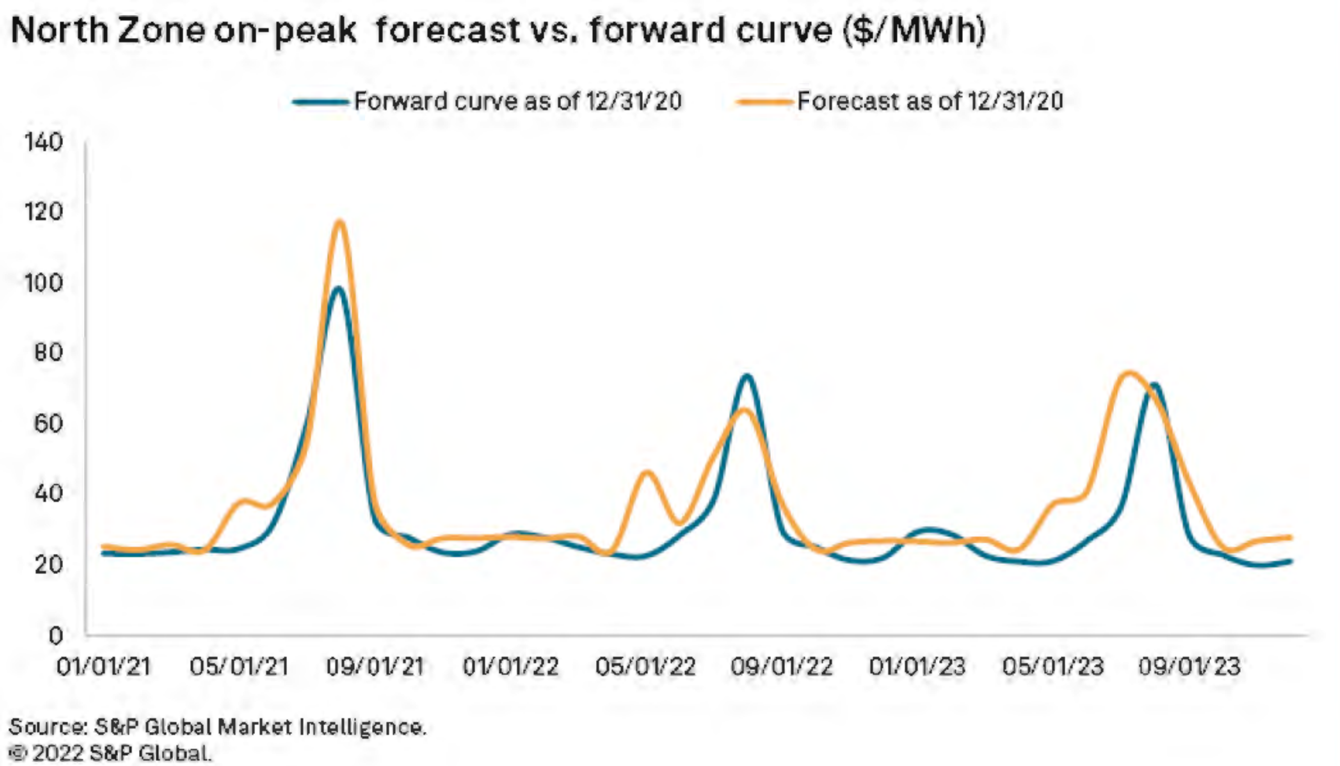
Backtesting - An important element of any forecast is validation of results against historical outcomes. Market Intelligence conducted extensive back-casting for market areas using historical reported information on demand, resources available, maintenance and other outages as well as hydro output to inform model inputs. A variety of output were then compared to historical data including information on area power prices, fuel burn, generation by specific fuel/technology combinations, as well as transmission flows between regions. Discrepancies in results served as launching points for further review of inputs to identify where model improvements were needed with a strong emphasis put on finding hard data to support any needed input changes. An example of backtesting results of power prices for Mass Hub of ISO New England is shown below:



[PS3]

Comparison to forward market-indicatives in the initial forecast development, and each quarter before a new forecast is released, Market Intelligence validates results against market indicatives. Examples of this include comparing near-term to intermediate term generated price results against market indicatives from NYMEX as well as power forward publishers Amerex and Tradition Financial Services, comparing long-term prices results against the EIA annual energy outlook, and examining projected fuel balances against information projected by the EIA. The chart below shows an example of comparison of forecast energy prices in ERCOT North Zone to market indicatives reported by forward index providers for comparably dated forward transactions.

Exhibit 13 – Forward market comparison

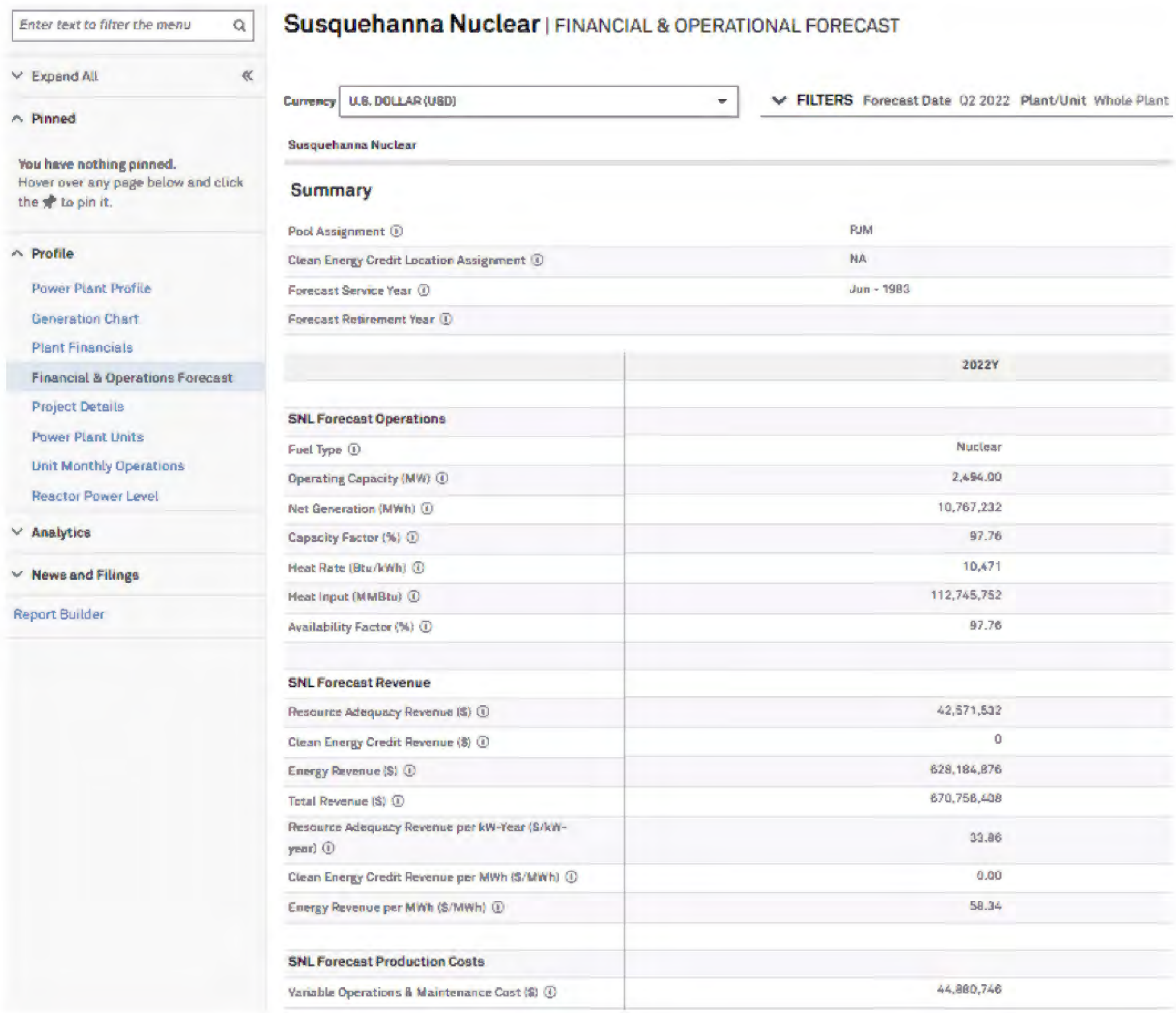


[PS4]

Discrepancies against market indicatives can arise for several reasons and Market Intelligence seeks to understand factors causing forward market indicatives to deviate from fundamental projections. Additionally, Market Intelligence examines forecast results from a high-level to make sure that these are consistent with the market "story", or that departures from market observations are explainable and defendable. In this respect, Market Intelligence forecast results are intended to reflect both logical consistency and alignment with the observable market, helping to ensure an accurate, transparent, and market-relevant forecast.

Power Plant pro-forma Projections of Operations and Revenue

The Power Forecast provides power plant level projections of operations, revenues, and expenses associated with each forecast release (beginning Q4 2015). For individual power plants and units, this data may be accessed via the Power Plant briefing book as follows:



Pool Assignment	PJM
Clean Energy Credit Location Assignment	NA
Forecast Service Year	Jun - 1983
Forecast Retirement Year	

	2022Y
SNL Forecast Operations	
Fuel Type	Nuclear
Operating Capacity (MW)	2,494.00
Net Generation (MWh)	10,767,232
Capacity Factor (%)	97.76
Heat Rate (Btu/kWh)	10,471
Heat Input (MMBtu)	112,745,752
Availability Factor (%)	97.76
SNL Forecast Revenue	
Resource Adequacy Revenue ($)	42,571,532
Clean Energy Credit Revenue ($)	0
Energy Revenue ($)	628,184,876
Total Revenue ($)	670,756,408
Resource Adequacy Revenue per kW-Year ($/kW-year)	33.86
Clean Energy Credit Revenue per MWh ($/MWh)	0.00
Energy Revenue per MWh ($/MWh)	58.34
SNL Forecast Production Costs	
Variable Operations & Maintenance Cost ($)	44,880,746

Note that this selection will only show as available for power plants Market Intelligence forecasts and will only open for Power Forecast subscribers. While the Power Forecast provides projections for most contiguous U.S. generating assets, cogenerators and assumed off-grid generators are not forecast.

Select Box – Users may toggle settings in the select box to change the forecast date (beginning with the first release of power plant projections, Q4 2015), to change whole plants vs. unit view, or to change forecast years displayed.

Current Year Projections – Power Forecasts are issued as of the close of each quarter, whereas power plant projections are displayed on an annual basis. The default first year displayed is the prompt year, or the first complete year of forecast data. The user may also opt to display the current year; however please note that current year forecasts represent Market Intelligence's projection for the *balance* of that year. The portion of the current year represented in the projections depends on the forecast release quarter, as follows:

- Forecasts released as of the close of Q1 include projections for the balance of the current year for the 9 months April-December.
- Forecasts released as of the close of Q2 include projections for the balance of the current year for the 6 months July-December.
- Forecasts released as of the close of Q3 include projections for the balance of the current year for the 3 months October-December.
- Forecasts released as of the close of Q4 include projections for the entire current/prompt year (first year of the forecast).

Resource Adequacy Revenue Projection – Market Intelligence's estimated revenues for forward capacity are based on the Power Forecast capacity price for the region in which the power plant is located. While capacity compensation rules vary somewhat for regions with organized capacity auctions, Market Intelligence's general calculation of capacity revenue is as follows:

Capacity Revenue = {Capacity Price Forecast ($/kW-month)} X {Operating Capacity (kW)} X {Peak Credit (factor)}, where the 'Peak Credit' is an estimated value that accounts for expected availability of a generating resource at the time of regional system peak. Intermittent resources (such as wind, solar and traditional hydroelectric) typically receive a discount to the generating unit's peak season Operating Capacity, whereas non-intermittent resources receive the full Operating Capacity unless they are located in a market priced on Unforced Capacity, or UCAP such as MISO, NYISO or PJM.

On-line and out-of-service dates for generating units also impact attribution of capacity revenues in some markets. Typically, a generator who is not on-line for any portion of a reliability year receives no revenue for that reliability year. The estimate of capacity revenues accounts for partial year availability due to on-line and out-of-service dates.

Additional information regarding capacity price modelling may be found **here**

Clean Energy Credit Revenue Projection – Market Intelligence's estimated revenues for Renewable Energy Credits are included in this line item. If REC revenues are assigned to the asset, there will be a value shown in the Clean Energy Credit Location Assignment field designating which market MI believes it sells into. Forecast REC revenues are calculated as Net Generation (MWh) X the corresponding price for the REC instrument assigned in that year.

Fuel Expenses –These are derived from projections of delivered fuel prices to individual power plants and generating units as developed for the Power Forecast. Note that the process for projecting delivered fuel prices may differ from other sources of forward fuel price estimates on S&P Global Market Intelligence, such as the Generating Supply Curve application.

Additional information regarding projections of future fuel prices may be found **here**

Operating & Maintenance Expenses –The process for projecting O&M expenses uses Fixed O&M and Variable O&M rates consistent with the estimation process used for the Generating Supply Curve application. However, in some cases announced or projected pollution control retrofits may increase projected O&M costs for some generating units. Note also that for some classes of generating units, the Power Forecast attributes O&M costs using the 80/20 convention, as described **here**

Applicability of Error Guarantee to Power Forecast Content

Power Forecast power plant projections of revenues and expenses rely on Market Intelligence's best judgement about input data known to S&P Global Market Intelligence analysts at the time of the production cycle and when projections are assembled. Projection results rely on simulation of sales of energy and capacity into an open wholesale market, the imputed costs of running the power plants, and revenues from making those sales. These projections can be influenced by S&P Global Market Intelligence's expert judgement on several factors including (but not limited to): timing of generator in-service/out of service, generator location, projected origin and forecast cost of fuel supply, or rated capacity during operation. S&P Global Market Intelligence does not guarantee the accuracy of projections under the S&P Global Market Intelligence error policy. Reported data that can be accessed in other locations within the Market Intelligence product and are applied to asset-level projections remains subject to the error guarantee.

Client Support and Training

Client Support

S&P Global Market Intelligence provides multifaceted client support as follows.

- Market Intelligence maintains 24/7 help desks around the world, including specialized client support groups in London, New York, and Hyderabad (India), to provide the optimum level of support. Dedicated fulltime client support employees are based in New York, Denver, London, Hong Kong, Singapore, Tokyo, Melbourne, Manila, and Islamabad.

- Data and technical support are integrated into a single global team. S&P Global Market Intelligence's client support team manages deployment schedules and operational set-up, supports full implementation, and handles all data inquiries. The team takes the initial client call or email, triages it and attempts to resolve it. Defined data and technical escalation procedures are in place to ensure a timely response to client issues. The model is designed to provide accessible contact points via telephone or email. Defined data and technical escalation procedures are in place to ensure a timely response to client issues.

  – S&P Capital IQ Platform: +852-2533-3565 or support.CIQ@spglobal.com
  – Market Intelligence Desktop: +852-5808-0983 or support.MI@spglobal.com

- The screening and platform group consults with clients on how to reap maximum benefit using the Platform, by drawing from deep financial and product expertise; and provides expert guidance on utilizing the Screening tool, building complex screens on a client's behalf, and tailoring the look and feel of the Platform to facilitate the client's specific-workflow needs.

- The financial modelling group creates, converts, and troubleshoots financial models and maintains more than 75 pre-built templates, made available via the proprietary Excel Plug-in. The custom solutions group (CSG) provides extensive model and Real-Time workstation conversion as well as data integration services, for S&P Global Market Intelligence sophisticated analytical tools, so that clients can have a tailored experience. This global, seasoned team specializes in on-boarding and client adoption for the Excel Plug-In, proprietary data, workstation, and screening and Platform capabilities. Comprised of former investment bankers, MBA and CFA-level professionals have sector experiences in many industries.

- Market Intelligence industry-sector specific support analysts specialise on each of the industries – energy, financial institutions, insurance, markets and deals, media and communications, metals and mining and real estate – to address client queries comprehensively.
  - *Specialised industry data and news*: Access to a wide range of sector-focused data, including financial, market, peer, and demographic information
  - *Deep, sector-specific analysis*: Clients are able to dig into ratios and meaningful metrics that are specific to their industry, and review data-driven research, analysis, and sector projections
  - *Expert commentary and research*: Sector-specific research papers, infographics, and webinars from our experts. Clients find rankings of companies in the sectors they cover, and expand their knowledge with online and in-person training seminars
  - *Custom reporting and consulting*: Build models tailored to client workflow or leverage consulting services for expert valuations, custom studies, white papers, and more.

Training

S&P Global Market Intelligence provides training for the Platform for content and functionality as well as workflow and can be at the individual or account level.

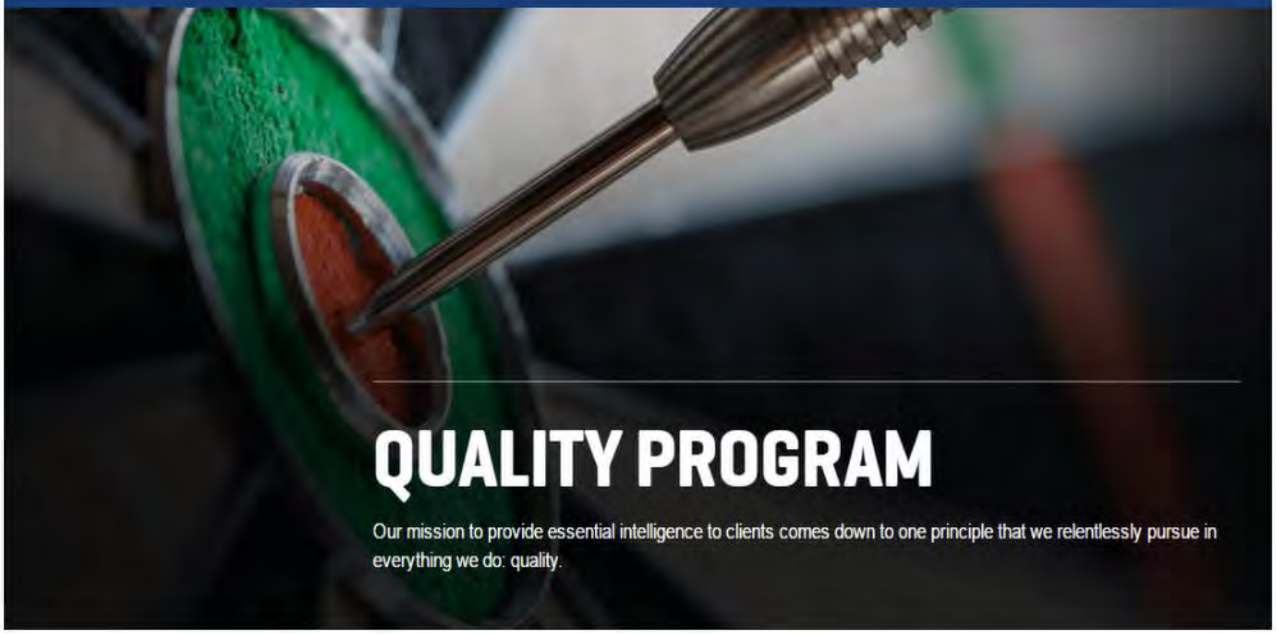
- Workshops are conducted by S&P Global Market Intelligence analysts with specialization the in the area of expertise in the relevant methodology to ensure comprehensive knowledge transfer.
- Training is provided in-person or via WebEx
- Technical documentation and release notes are available
- The Platform has a library of stored training webinars for on-demand functionality training

In addition, S&P Global Market Intelligence provides thought leadership and training webinars that focus specifically on credit trends, research, and usability. Clients learn best practices in the former and specific use cases in the latter.

Quality Program

S&P Global Market Intelligence strives to produce and deliver data that clients can count on. It collects approximately 135 billion data points each year and provides them on via its desktop and data feeds for users to enhance their workflow. S&P Global Market Intelligence even offers clients a $50 reward for each data quality issue that is successfully validated, as depicted below.

S&P Global Market Intelligence is very passionate about delivering the highest possible degree of quality, timeliness, and completeness in its corporate, market, and financial information that it challenges its clients to tell it when it has missed the mark. It even offers $50 rewards for qualified submissions.



S&P Global Market Intelligence runs a robust process to determine all systematic data errors. There are more than 145,000 data quality checks per year and content is reviewed multiple times before publishing. After a mistake is verified, analysts begin a thorough testing process to verify the discrepancy and get to the root cause of how it ended up in the database. The discrepancies are corrected, and new data content is published in the database. S&P Global Market Intelligence tracks these database changes and sends out a file on daily changes: additions, deletions, and updates.

Staff Exhibit JTG-11

Southwest Power Pool

RESOURCE PORTFOLIO UNCERTAINTY AND LOLE/EUE METRICS

Working together to responsibly and economically keep the lights on today and in the future.

SouthwestPowerPool SPPorg southwest-power-pool

CONSIDERATION OF RELIABILITY OF PRM VALUES ACROSS DIFFERENT SOLAR BUILDOUT

Scenario	Aggressive Solar – 33% PRM	Existing Solar – 33% PRM	Aggressive Solar – 36% PRM	Existing Solar - 36% PRM
Solar Penetration (nameplate MW)	4,828MW	444MW	4,828MW	444MW
LOLE (Winter)	**0.05**	**0.08**	**0.03**	**0.05**
EUE (Winter)	**868**	**1,132**	**355**	**572**
Base PRM (Winter)	33%	33%	36%	36%

- By focusing only on LOLE in an aggressive solar buildout, excessive EUE may be encountered
- 33% PRM not only runs a risk of excessive EUE, but also runs risk of violating the LOLE metric (0.08 LOLE for the winter season) if an aggressive solar buildout is not achieved.
- 36% PRM provides assurance that EUE is less than or equal to the risk posed by today's solar fleet, but also that the LOLE metric of 0.05 LOLE can be maintained if an aggressive solar buildout is not achieved.

CONSIDERATION OF SEASONAL RISK WITH EXISTING SOLAR BUILDOUT

Scenario	Existing Solar – Winter	Existing Solar – Summer
Season	Winter	Summer
Solar Penetration (nameplate MW)	444MW	444MW
LOLE (Seasonal)	**0.08**	**0.02**
EUE (Seasonal)	**1,132**	**47**
PRM (Winter)	33%	18%

- With less aggressive solar buildout, 33% PRM provides less capacity and risk moves to the winter (from 0.05 LOLE to 0.08 LOLE)
- To account for the increased risk in winter, less risk can be allowed for in the summer, which leads to the need for the summer PRM to increase to 18%

SEASONAL 2026 PRM DRAFT RESULTS WITH VARYING LOLE LEVELS

Recommended PRM for the 2026-2027 Winter Season is 36% and 16% for the 2026 Summer Season

Incremental Cold Weather Outage	Varying LOLE with P&M for Winter																			
	0.01		0.02		0.03		0.04		0.05		0.06		0.07		0.08		0.09		0.1	
	PRM	EUE	PRM	EUE	PRM	EUE	PRM	EUE	PRM	EUE	PRM	EUE	PRM	EUE	PRM	EUE	PRM	EUE	PRM	EUE
0%	29%	37	28%	91	28%	147	27%	203	27%	264	26%	327	26%	389	26%	451	26%	514	26%	576
25%	36%	32	34%	140	32%	276	31%	426	30%	570	30%	684	29%	797	29%	911	29%	1,024	28%	1,137
50%	43%	41	40%	129	37%	359	36%	576	35%	773	35%	961	35%	1,150	35%	1,338	34%	1,527	34%	1,716
75%	51%	33	47%	144	44%	391	42%	639	40%	910	39%	1,151	38%	1,388	37%	1,655	37%	1,928	36%	2,202
100%	61%	30	54%	146	50%	463	48%	767	46%	1,048	45%	1,270	44%	1,551	43%	1,856	42%	2,122	41%	2,366

Incremental Cold Weather Outage	Varying LOLE without P&M for Winter																			
	0.01		0.02		0.03		0.04		0.05		0.06		0.07		0.08		0.09		0.1	
	PRM	EUE	PRM	EUE	PRM	EUE	PRM	EUE	PRM	EUE	PRM	EUE	PRM	EUE	PRM	EUE	PRM	EUE	PRM	EUE
0%	28%	46	26%	113	25%	194	24%	282	24%	370	24%	458	23%	546	23%	633	23%	721	22%	825
25%	35%	40	32%	131	30%	278	29%	475	28%	678	28%	795	27%	911	27%	1,028	26%	1,144	26%	1,264
50%	42%	34	39%	145	36%	355	35%	612	33%	868	32%	1,090	32%	1,313	31%	1,536	30%	1,761	30%	1,985
75%	49%	38	46%	136	42%	383	40%	648	39%	906	37%	1,193	36%	1,502	35%	1,843	34%	2,206	34%	2,542
100%	59%	40	53%	155	48%	439	46%	701	45%	978	43%	1,306	42%	1,663	41%	2,042	40%	2,414	39%	2,784

Scenairo	Varying LOLE for Summer																			
	0.01		0.02		0.03		0.04		0.05		0.06		0.07		0.08		0.09		0.10	
	PRM	EUE	PRM	EUE	PRM	EUE	PRM	EUE	PRM	EUE	PRM	EUE	PRM	EUE	PRM	EUE	PRM	EUE	PRM	EUE
Summer	18%	24	18%	53	17%	85	17%	117	16%	152	16%	198	16%	244	15%	290	15%	336	15%	423

SOLAR SENSITIVITY – WINTER PRM IMPACT

33% Winter Base PRM
With 4,828 MW Solar

- Winter LOLE = 0.05
- Winter EUE = 868 MWh

- Base resource assumptions
- 50% Incremental CWO
- No Planned and Maintenance Outages

33% Winter Base PRM
With 444 MW Solar (existing)

- **Winter LOLE = 0.08**
- Winter EUE = 1,132 MWh

With no additional solar and at same PRM, EUE increases less rapidly than LOLE. At lower penetrations of Solar, LOLE is the more critical reliability metric. **There is no longer a 0.05/0.05 Winter/Summer balance of LOLE risk**

SOLAR SENSITIVITY – WINTER PRM IMPACT

35.6% Winter Base PRM
With 444 MW Solar

- Winter LOLE = 0.05
- Winter EUE = 572 MWh

Holding LOLE constant, PRM increases and EUE decreases with lower Solar penetration

36% Base PRM would help stabilize risk and EUE due to delays in solar installations

Docket No. 25-EKCE-207-PRE

Public Responses

to Data Requests

Staff Exhibit JTG-13

Evergy Kansas Central
Case Name: 2025 EKC Predetermination
Case Number: 25-EKCE-207-PRE

Requestor Grady Justin -
Response Provided February 07, 2025

Question:KCC-3
Regarding: Update to SPP PRMs

Please Provide the Following:

In the 2024 IRP, Evergy assumed a Summer PRM of 17% in 2026, 20% in 2029, and 21% in 2030-2032. For Winter, Evergy assumed a Winter PRM of 32% in 2026, 33% in 2027, 35% in 2029,
and 37% from 2030-2032.

The SPP Board recently approved a PRM of 16% in the Summer of 2026, and 36% in the Winter of 2026. The SPP stakeholder community (SAWG, REAL, CAWG), with RSC set to vote next week, on a Summer PRM of 17% for 2029, and 38% for Winter 2029.

It looks like Evergy's 2024 IRP overestimated the Summer PRM in 2026 and 2029 (based on these
current SPP approved PRMs) and underestimated the Winter PRM for 2026 and 2029 (again, based
on the currently approved PRMs, and what appears highly likely to be approved by the Board on February 4th).

Please provide the following regarding the projected PRMs, and these updated PRMs.

How does this updated information on Summer and Winter PRMs affect the results of the 2024 IRP, and the resulting preferred plans of EKC and EKM if any?

How does this updated information on Summer and Winter PRMs affect the resource acquisitions that Evergy has asked the Commission to rule on in this predetermination proceeding? Has this
updated information changed Evergy's decision in any way? If not, please explain why not.

If the SPP Board does approve the more recent PRMs described earlier in my question, and those PRMs are approved by FERC, how would that quantitatively affect the required reserve margin surplus or shortage of both EKC and EKM from 2026 through 2030? Please provide this quantification in terms of what is reflected in the workpapers 2024 IRP and predetermination docket now, versus what the resulting reserve margin surplus or shortage would be if the modeling in the 2024 IRP and Predetermination were updated to reflect these revisions.

RESPONSE: (do not edit or delete this line or anything above this)

Confidentiality: PUBLIC
Statement: Choose an item.

Response:

The Company does not believe the latest updated information from SPP significantly impacts the 2024 IRP, this predetermination case, or Evergy's decision to pursue the new generation assets in the predetermination case. The future Planning Reserve Margins used for IRP purposes requires some level of estimate as the Company has very little long-term certainty of where SPP's PRM will be set. At the time of finalizing planning assumptions for each IRP, the Company determines it's best estimate, which is informed by SPP current requirements and the indicative future requirement levels that the Company learns about through the SPP stakeholder process. Volume 5 Section 2 of the 2024 IRP details the Company's approach to resource adequacy planning criteria. This section of the IRP explains how SPP uses a Loss of Load Expectation study to set PRMs and explains the many changing resource adequacy methodologies that are factors to SPP setting the PRM level. As SPP finalizes near-term PRM requirements over time, the Company expects to calibrate its planning assumptions commensurate with the next IRP cycle. For example, as stated in this request, since filing the 2024 IRP, SPP has advanced its 2029 summer and winter PRM indications and is in the process of formalizing the requirements. Evergy has taken this into consideration for it's 2025 IRP Annual Update and plans to calibrate the PRM for modeling purposes. Although this could drive a slight change in PRM modeling assumptions, the Company does not feel it materially impacts the 2024 IRP. The fact of the matter is that there is a growing need for future incremental capacity and the near-term assets that are part of this predetermination request are still needed.

The Company views the SPP PRM requirement as a floor for the reserve margin used in IRP modeling. As SPP makes changes to their resource adequacy rules, there is inherit uncertainty in the calculations used to determine generation asset accreditation and the impacts to each utility's accredited PRM requirement. While SPP is working to formalize future Installed Capacity (ICAP) PRMs; the Accredited Capacity (ACAP) will continue to be a moving target to a certain extent. With SPP's advent of Performance-Based Accreditation, Effective Load Carrying Capability (ELCC), and Fuel Assurance it will be much more difficult for utilities to predict future capacity accreditation. For example, as the Company must comply with PBA moving forward, a winter outage at a base load unit for the whole season could decrease a utility's reserve margin by a full percentage point. And after SPP rules go into effect, this reserve margin impact will be part of the PBA calculation for the unit in this example for seven straight years.

The attached file displays the quantitative impact of the required reserve margin surplus or shortage of both EKC and EKM from 2026 through 2030, comparing the 2024 IRP/Predetermination work papers versus the current indicative SPP PRM requirements.

Information provided by: Cody VandeVelde, Sr. Dir. Strategy & Long-Term Planning

Attachment(s): DR KCC-3_Reserve Margin Analysis.xlsx

Verification:

I have read the Information Request and answer thereto and find answer to be true, accurate, full and complete, and contain no material misrepresentations or omissions to the best of my knowledge and belief; and I will disclose to the Commission Staff any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this Information Request(s).

Signature /s/ *Brad Lutz*
Director Regulatory Affairs

Evergy Kansas Central
Case Name: 2025 EKC Predetermination
Case Number: 25-EKCE-207-PRE

Requestor Grady Justin -
Response Provided February 11, 2025

Question:KCC-11
Regarding: 40% Capacity Factor Limitation

Please Provide the Following:

Please provide the following pertaining to the EPC RFP to construct Kansas Sky:

In Evergy witness Code Vandevelde's Direct Testimony he discusses an updated IRP analysis Evergy performed for this predetermination proceeding that evaluated the higher estimated cost of the combined cycle generating units, as
compared to the 2024 IRP analysis. The spreadsheet provided in the Evergy workpapers that contains the output of this capacity expansion modeling identifies yearly modeled capacity factors for the 2030 Combined Cycle generator at line 521 of the spreadsheet. There are several instances of modeled capacity factors that are higher than 40% during the period 2032 to 2043. Please provide the following:

1. Has Evergy performed capacity expansion modeling similar to that provided in this Docket, that limited the 2030 Combined Cycle generator to a 40% yearly capacity factor for all years after 2032, in accordance with the
current Final GHG rules promulgated by the EPA? If so, please provide the results of that modeling in a spreadsheet similar to "Conf. EKC Plan Selected with Updated NG Costs" as provided in the Workpapers.

2. If Evergy has not performed the modeling discussed in Item No. 1 above, please explain why Evergy cannot perform this modeling or why Evergy does not believe that information is relevant to the Commission's decision
in this proceeding.

RESPONSE: (do not edit or delete this line or anything above this)

Confidentiality: PUBLIC
Statement: This response is Public. No Confidential Statement is needed.

Response:

For the 2024 IRP, Evergy used capacity expansion to formulate GHG compliant plans consistent with its expectations for a final rule, prior to that rule being issued. Evergy's scenarios were informed by the proposed rule and industry feedback. The expected options for new combined cycles at the time were hydrogen blending – 30% 2032-2037 and 96% 2038 and beyond, or carbon capture and sequestration at 90% rate 2035 and beyond. Evergy studied the carbon capture and sequestration 2035 pathway in its models.

Evergy can limit combined cycle generator output to a 40% capacity factor in its modeling software and will provide updated GHG compliance scenarios in its 2025 IRP Annual Update.

Evergy has not yet completed final modeling for the 2025 IRP. Long-term planning inherently has many uncertainties and long-lead-time resource decisions have to be made with incomplete and imperfect information about the future. Evergy identified environmental rules for carbon dioxide emissions as a critical uncertain factor in the 2024 Triennial IRP and analyzed three different levels of emissions reductions as part of the economic evaluation of the resource plans. It is unclear what the future holds for the GHG final rule, given the change of US presidential administration. Evergy does expect emission reductions to be part of future policy over the planning horizon and the highly efficient advanced combined cycle technology employed by these new resources will produce firm dispatchable energy with much lower carbon dioxide emissions rates than existing coal, natural gas, and oil-fired dispatchable resources.

Information provided by:
Kelli Merwald, Sr. Mgr. Fundamental Analysis
Attachment(s):

Verification:
I have read the Information Request and answer thereto and find answer to be true, accurate, full and complete, and contain no material misrepresentations or omissions to the best of my knowledge and belief; and I will disclose to the Commission Staff any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this Information Request(s).

Signature /s/ *Brad Lutz*
Director Regulatory Affairs

Evergy Kansas Central
Case Name: 2025 EKC Predetermination
Case Number: 25-EKCE-207-PRE

Requestor Grady Justin -
Response Provided February 10, 2025

Question:KCC-15
Regarding: Winter Operating Temperatures

Please Provide the Following:

Page 30 of Evergy witness Kyle Olson's Direct Testimony states that the Combined Cycle generators
that are the subject of this proceeding can continue conducting normal operations in temperatures as low as minus10 degrees Fahrenheit. Does Mitsubishi Power o□er a cold weather package for JAC turbines that would allow the unit to operate at temperatures below minus 10 degrees? If so, has Evergy requested or received a bid pertaining to the cost adjustment that would be necessary to achieve that colder weatherization standard?

RESPONSE: (do not edit or delete this line or anything above this)

Confidentiality: PUBLIC
Statement: This response is Public. No Confidential Statement is needed.

Response:

Evergy based the minimum temperatures on a review of ASHRAE weather stations located nearest to each site. The ASHRAE 50-year minimum was used as the minimum temperature for freeze protection and material selection calculations.

During final PIE negotiations with MPWA, at the request of Evergy, MPWA agreed to drop the minimum temperature to -15 degrees Fahrenheit, instead of -10 degrees.

Evergy has not requested and is not aware if Mitsubishi Power offers a cold weather package for JAC combined cycle turbines that would allow the unit to operate at temperatures below minus 15 degrees.

Information provided by: J Kyle Olson, Director – Conventional Generation Development

Attachment(s):

Verification:
I have read the Information Request and answer thereto and find answer to be true, accurate, full and complete, and contain no material misrepresentations or omissions to the best of my knowledge and belief; and I will disclose to the Commission Staff any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this Information Request(s).

Signature /s/ *Brad Lutz*
Director Regulatory Affairs

Evergy Kansas Central
Case Name: 2025 EKC Predetermination
Case Number: 25-EKCE-207-PRE

Requestor Grady Justin -
Response Provided February 10, 2025

Question:KCC-22
Regarding: Kansas Sky PTC Eligibility

Please Provide the Following:

As discussed in the Direct Testimony of John Grace, the Kansas SKY LCOE Model assumes that the solar project will qualify for a 110% PTC amount pursuant to the Inflation Reduction Act (IRA). What level of certainty does Evergy have that this facility will qualify for these tax credits under the IRA? If there is a change in to the solar tax credits in the IRA in 2025 or 2026 under a new administration in Washington, what options does Evergy have to ensure that this solar facility still qualifies for the PTCs?

RESPONSE: (do not edit or delete this line or anything above this)

Confidentiality: PUBLIC
Statement: Choose an item.

Response:

According to the US Department of Energy, the location for Kanas Sky ((Lawrence Energy Site (Census tract 20045000100)) qualifies as a location eligible for the energy community bonus credit.

Below is a link:
https://edxspatial.arcgis.netl.doe.gov/experience_builder/IWGSiteReviewTool/index.html#data_s=id%3AdataSource_4-18eee6101e4-layer-20-18f5ed492f7-layer-17%3A30878

Any change to the production tax credits or investment tax under the new administration in Washington is speculative and the Company would need to assess any change to the IRA.

Information provided by: John M. Grace; Sr. Dir. Corporate Planning and Financial Performance

Attachment(s):

Verification:
I have read the Information Request and answer thereto and find answer to be true, accurate, full and complete, and contain no material misrepresentations or omissions to the best of my knowledge and belief; and I will disclose to the Commission Staff any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this Information Request(s).

Signature /s/ *Brad Lutz*
Director Regulatory Affairs

Evergy Kansas Central
Case Name: 2025 EKC Predetermination
Case Number: 25-EKCE-207-PRE

Requestor Grady Justin -
Response Provided February 13, 2025

Question:KCC-40
Regarding: Natural Gas Price Forecasting in 2024 IRP

Please Provide the Following:

1. Please provide the workpapers that contain the natural gas price forecasts (Low, Base, and Mid) from the 2024 IRP.

2. Were the natural gas price forecasts used in the 2024 IRP representative of local natural gas prices that could be expected to be purchased on pipelines near the proposed location of the two combined cycle facilities that are the subject of this predetermination proceeding, or were the natural gas price forecasts based on Henry Hub natural gas prices?

3. If the answer to No. 2 above is that the natural gas price forecasts in the 2024 IRP are based on Henry Hub natural gas prices, please explain why that does not invalidate the results of Evergy's 2024 IRP analysis, given the basis differentials historically observed between local natural gas prices and the Henry Hub natural gas price.

RESPONSE: (do not edit or delete this line or anything above this)

Confidentiality: PUBLIC
Statement: This response is Public. No Confidential Statement is needed.

Response:

The natural gas prices were based on local delivery. The forecasts were developed using Henry Hub prices as the commodity, as these prices are much more widely forecasted and traded into the future. The Henry Hub price was scaled to create a high and low based on the EIA Annual Energy Outlook long term fundamental price forecasts. A basis differential was added to all three price series (mid, high, low) based on the expected Panhandle East gas delivery location basis.

Information provided by:

Kelli Merwald, Sr. Mgr. Fundamental Analysis
Attachment(s):
Q_KCC-40_IRP 2024 NG Prices

Verification:
I have read the Information Request and answer thereto and find answer to be true, accurate, full and complete, and contain no material misrepresentations or omissions to the best of my knowledge and belief; and I will disclose to the Commission Staff any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this Information Request(s).

Signature /s/ *Brad Lutz*
Director Regulatory Affairs

Evergy Kansas Central
Case Name: 2025 EKC Predetermination
Case Number: 25-EKCE-207-PRE

Requestor Grady Justin -
Response Provided February 13, 2025

Question:KCC-42
Regarding: Natural Gas Price Firm Transportation Modeling in 2024 IRP

Please Provide the Following:

Please describe how Evergy has estimated the costs of Firm Natural Gas Transportation for the Combined Cycle units that are the subject of this predetermination. How were these costs estimated and modeled in the 2024 IRP? Were they modeled separately from the variable commodity costs? Included as fixed costs per kW/Year as part of the costs of operating the plant?

RESPONSE: (do not edit or delete this line or anything above this)

Confidentiality: PUBLIC
Statement: This response is Public. No Confidential Statement is needed.

Response:
Firm Natural Gas Transportation costs were estimated based on the pipeline tariff rate schedules. They were included as fixed costs and modeled with $/kW-year with other fixed O&M. Firm Transport is expected to be contracted annually (or more likely for multiple years) and only assures availability of pipeline capacity at the time of use. Natural gas commodity costs were modeled separately as variable costs.

Information provided by:
Kelli Merwald, Sr. Mgr. Fundamental Analysis
Attachment(s):

Verification:
I have read the Information Request and answer thereto and find answer to be true, accurate, full and complete, and contain no material misrepresentations or omissions to the best of my knowledge and belief; and I will disclose to the Commission Staff any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this Information Request(s).

Signature /s/ *Brad Lutz*
Director Regulatory Affairs

Evergy Kansas Central
Case Name: 2025 EKC Predetermination
Case Number: 25-EKCE-207-PRE

Requestor Grady Justin -
Response Provided February 19, 2025

Question:KCC-43
Regarding: Carbon Dioxide Emissions Levels

Please Provide the Following:

Please provide the Carbon Dioxide Emissions levels of each existing Evergy Kansas Central generating unit, and the proposed Combined Cycle units, in terms of Lbs of C02 per MWh.

RESPONSE: (do not edit or delete this line or anything above this)

Confidentiality: PUBLIC
Statement: This response is Public. No Confidential Statement is needed.

Response:

Existing Generating Units
The following emission rates are all in pounds per megawatt-hour gross (lb/MWh-gross). The emission rates are based on a three-year (2022 – 2024) average for each unit.

Jeffrey Energy Center Unit 1 – 1,943
Jeffrey Energy Center Unit 2 – 2,090
Jeffrey Energy Center Unit 3 – 2,046
La Cygne Generating Station Unit 1 – 2,016
La Cygne Generating Station Unit 2 – 2,063
Lawrence Energy Center Unit 4 – 2,157
Lawrence Energy Center Unit 5 – 1,963
Gordon Evans Energy Center Combustion Turbine 1 – 1,473
Gordon Evans Energy Center Combustion Turbine 2 – 1,528
Gordon Evans Energy Center Combustion Turbine 3 – 1,311
Emporia Energy Center Combustion Turbine 1 – 1,471
Emporia Energy Center Combustion Turbine 2 – 1,499
Emporia Energy Center Combustion Turbine 3 – 1,569

Emporia Energy Center Combustion Turbine 4 – 1,537
Emporia Energy Center Combustion Turbine 5 – 1,377
Emporia Energy Center Combustion Turbine 6 – 1,407
Emporia Energy Center Combustion Turbine 7 – 1,347
Hutchinson Energy Center Combustion Turbine 1 – 2,601
Hutchinson Energy Center Combustion Turbine 2 – 2,574
Hutchinson Energy Center Combustion Turbine 3 – 2,690
Hutchinson Energy Center Combustion Turbine 4 – 9,937
Spring Creek Energy Center Combustion Turbine 1 – 1,593
Spring Creek Energy Center Combustion Turbine 2 – 1,601
Spring Creek Energy Center Combustion Turbine 3 – 1,589
Spring Creek Energy Center Combustion Turbine 4 – 1,598

New Generating Units
For the Viola and McNew Energy Centers Combustion Turbines:

> These units will be capable of meeting the CO_2 emission limitations applicable at the time of operation for a combined cycle combustion turbine. The applicable CO_2 emission limitations will be either 800 lb/MWh (40 Code of Federal Regulations (CFR) Subpart TTTTa, Phase 1 emission limitation) or 1,000 lb/MWh (40 CFR Subpart TTTT) if 40 CFR Subpart TTTTa is repealed.

Information provided by:

Daniel R. Wilkus, Director, Environmental Services

Attachment(s):

Verification:
I have read the Information Request and answer thereto and find answer to be true, accurate, full and complete, and contain no material misrepresentations or omissions to the best of my knowledge and belief; and I will disclose to the Commission Staff any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this Information Request(s).

Signature /s/ *Brad Lutz*
Director Regulatory Affairs

Evergy Kansas Central
Case Name: 2025 EKC Predetermination
Case Number: 25-EKCE-207-PRE

Requestor Zakoura James -
Response Provided December 20, 2024

Question:KIC-2-2
RE: Discovery Provided to Others
Please Respond to the Information Request detailed below.

Reference the Evergy Integrated Resource Plan – Update for 2024, dated April 1, 2024.
https://investors.evergy.com/2024IRPUpdate Page 3
For Evergy Kansas Central

A. Please explain the meaning of the statement, appearing at page 3, to wit: "Preferred Plan includes a placeholder for an additional coal unit retirement in 2030."

B. Which EKC coal unit is designated as the "placeholder" coal unit?

C. On page 3, is the 674 MW "Retirement" of a coal asset in 2030, the "Placeholder?"

D. What are the criteria for determining whether the "placeholder" coal unit will or will not be retired in 2030?

E. If either or both, the proposed Viola and McNew natural gas electric generation units are constructed, will the "Placeholder" coal unit be retired in 2030?

F. If the "Placeholder" coal unit is not retired in 2030, what date in the future will the "Placeholder" coal unit be retired?

G. On page 3 of the Chart for 2024, is Lawrence Unit 5 included as an "Addition?"

H. On page 3 of the Chart for 2024, are the natural gas additions in 2029 and 2030, the proposed capacity from the proposed Viola and McNew plants?

I. On page 3 of the Chart for 2024, provide detail of the 650 MW addition of natural gas in 2031, including but not limited to the location, the cost of the facility, and whether its construction is required to retire any of the existing coal fired electric generation assets.

J. If retirement of the EKC coal fired generation units is extended for 6 years from the current proposed retirement dates, are the Viola and McNew proposed natural gas facilities required by EKC in 2029 and 2030?

K. Provide all documents that evidence the addition of 300 MW of solar in 2027 and 150 MW of solar in 2028.

RESPONSE: (do not edit or delete this line or anything above this)

Confidentiality: PUBLIC
Statement: This response is Public. No Confidential Statement is needed.

Response:

Objection: Evergy objects to DR 2-2 E, F and J in that each request is an incomplete hypothetical which does not sufficiently identify the necessary factors and variables in order to allow Evergy to reasonably respond to the question. Evergy objects to DR 2-2 I in that it is vague and ambiguous in its request that Evergy "provide detail" of the stated addition of natural gas in 2031. It is not clear or evident what is meant by "provide detail" and what detail or information is being requested, and therefore the request is vague and ambiguous. Evergy further objects to DR 2-2 K in that it is overly broad and unduly burdensome, specifically in that it requests production of all documents that evidence the addition of 300 MW of solar in 2027 and 150 MW of solar in 2028. The request inasmuch as it requests production of "all documents" supporting these additions is substantially overbroad and unduly burdensome. Evergy intends to provide timely responses to those subsections where no objection has been made. Evergy will similarly provide timely responses consistent with and in consideration of the above objections to subsections E, F, J, I and K.

A. The Preferred Portfolio for Evergy Kansas Central includes retiring Jeffrey 2 at the end of 2030. The economic analysis in the IRP showed similar costs for a portfolio that retired the resource and a portfolio that extended its operation with the addition of Selective Catalytic Reduction (SCR) equipment expected to be required for environmental compliance. While the plans had relatively similar cost expectations, the risks to customers were also considered in selecting a preferred portfolio. Due to the long lead time to build new thermal resources, Evergy Kansas Central must begin procurement and construction promptly to insure commercial operation of new combined cycles in 2029 and 2030. If these resources are not constructed, Evergy Kansas Central will not have flexibility to retire Jeffrey 2 (whether due to environmental costs/compliance, age/repair needs, etc.). In the modeling scenario where the Jeffrey 2 retirement was scheduled for 2039, an additional 750 MW of solar was needed by 2031, on top of the 750 MW in the preferred portfolio. While this is also a significant investment, it is not expected to have the reliability characteristics (capacity accreditation) to enable the Jeffrey 2 retirement. While the Jeffrey 2 retirement 12/31/2030 is part of the preferred portfolio, Evergy Kansas Central maintains the flexibility to modify the retirement date if future expectations change.

B. Jeffrey 2

C. No, that is the retirement of Jeffrey 3.

D. Evergy still has flexibility in determining the retirement date. The most pressing deadline is currently the state planning for the EPA's GHG Final Rule. If this Rule is enforced, Evergy must make commitments for its entire coal fleet to retire, or invest in natural gas infrastructure to co-fire or fully convert in order to remain operational. Evergy has not developed a compliance plan. If the Rule is not enforced, other decisions that would affect retirement decision timing are: lead time to invest in SCR/ changes to expected compliance dates, future expected performance of a facility approaching it's expected useful life, on-going availability of parts to maintain reliability of an aging facility, potential need to use the site and interconnection for a replacement resource, SPP retirement transmission/reliability study (about 2 years if resource not being replaced by a thermal resource). Generally, the retirement decision will be based on assessment of customer needs (load growth, reliability requirements), expected going-forward costs of operation, viability of continued operation, expected costs and viability of other alternatives should the resource retire.

E. Based on the 2024 IRP, the resources being constructed are necessary to retire the placeholder to insure that Kansas Central continues to meet its customer's reliability needs. However, the inverse is not true. The placeholder unit could continue to operate even with both new resources in operation.

F. The alternative date studied in the 2024 IRP was 12/31/2039. As explained in D., Evergy expects some flexibility in finalizing the future retirement date.

G. It was included to highlight that it will cease burning coal and fully operate on natural gas.

H. Yes, however the turbine size for Viola and McNew is larger than was expected at the time of the IRP release.

I. This resource has not been sited and equipment has not been procured.

J. No specific models were run for that scenario. The IRP plan extending Jeffrey 2 to a 2039 retirement included an extra 750 MW of early solar. A combustion turbine was needed in 2031 and more thermal builds were needed in the later 2030's.

K. The preferred portfolios included 600 MW of solar in 2027 (150 MW EMW, 150 MW EKC, 300 MW EM), and 450 MW of solar in 2028 (300 MW EKC, 150 MW EM). These are included in the IRP preferred portfolio discussion. Evergy Missouri West has procured 165 MW of solar to meet the 2027 need and filed for CCN in Missouri. Evergy Kansas Central has filed for predetermination in Kansas for the 150 MW Kansas Sky project for 2027. Projects have not been selected for 2028. Evergy Metro is still in negotiations and has not filed for CCN or predetermination for 2027 solar yet.

Information provided by:
Kelli Merwald, Sr. Mgr. Fundamental Analysis
Attachment(s):

Verification:
I have read the Information Request and answer thereto and find answer to be true, accurate, full and complete, and contain no material misrepresentations or omissions to the best of my knowledge and belief; and I will disclose to the Commission Staff any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this Information Request(s).

Signature /s/ *Brad Lutz*
Director Regulatory Affairs

Evergy Kansas Central
Case Name: 2025 EKC Predetermination
Case Number: 25-EKCE-207-PRE

Requestor Zakoura James -
Response Provided January 06, 2025

Question:KIC-4-9
RE: Discovery Provided to Others
Please Respond to the Information Request detailed below.

A. Reference page 11 of the 2024 Annual Report (PDF page 11), for the year ended December 31, 2023, https://investors.evergy.com/static-files/63bc8e3e-7c8f-41b1-b3f1-671e7722ef45 to wit: **"Transitioning Evergy's Generation Fleet":**

(i) Confirm that the statements made in the section "**"Transitioning Evergy's Generation Fleet,"** remain in each and every respect, the position of Evergy at the time of the verified answer to this Information Request No. 4 - 9.

RESPONSE: (do not edit or delete this line or anything above this)

Confidentiality: PUBLIC
Statement: This response is Public. No Confidential Statement is needed.

Response:

Evergy remains committed to a long-standing strategy to reduce CO_2 emissions in a cost-effective and reliable manner, as part of the company's broader strategy to advance affordability, reliability, and sustainability, and currently stands by the statements made in the 2023 Annual Report as generally reflective of the plan to Transition Evergy's Generation Fleet over time. As noted in the statement, Evergy's ability to achieve emission reduction goals is dependent on external factors. On one hand there are significant enabling activities that must occur for the transition to take place, like advancement of carbon-free generation technology and supportive energy policies and regulations. On the other hand, there are forces that could reduce Evergy's ability to achieve the goals, like higher load growth or sustained high commodity prices which could result in higher utilization levels of plants with higher carbon emissions. The on-going analysis of emission reduction targets is best served to be evaluated in tandem with long-term integrated resource planning, which Evergy will continue to perform as system and market conditions change.

As described in the predetermination filing here, this case is reflective of a plan to gradually transition our generation fleet and replace aging generation units (which are expected to face increasing equipment replacement and reinvestment requirements over time) while focusing on customer affordability, fuel diversity, and ensuring reliability for the customers and communities that we serve. These objectives were reflected in the 2024 Triennial Integrated Resource Plan and the selection of the preferred plan that largely minimizes the net present value of the revenue requirement for our customers over time while diversifying fuel supply with the addition of solar and natural gas generation units.

Information provided by: Jason Humphrey, Vice President Development

Attachment(s): None

Verification:
I have read the Information Request and answer thereto and find answer to be true, accurate, full and complete, and contain no material misrepresentations or omissions to the best of my knowledge and belief; and I will disclose to the Commission Staff any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this Information Request(s).

Signature /s/ *Brad Lutz*
Director Regulatory Affairs

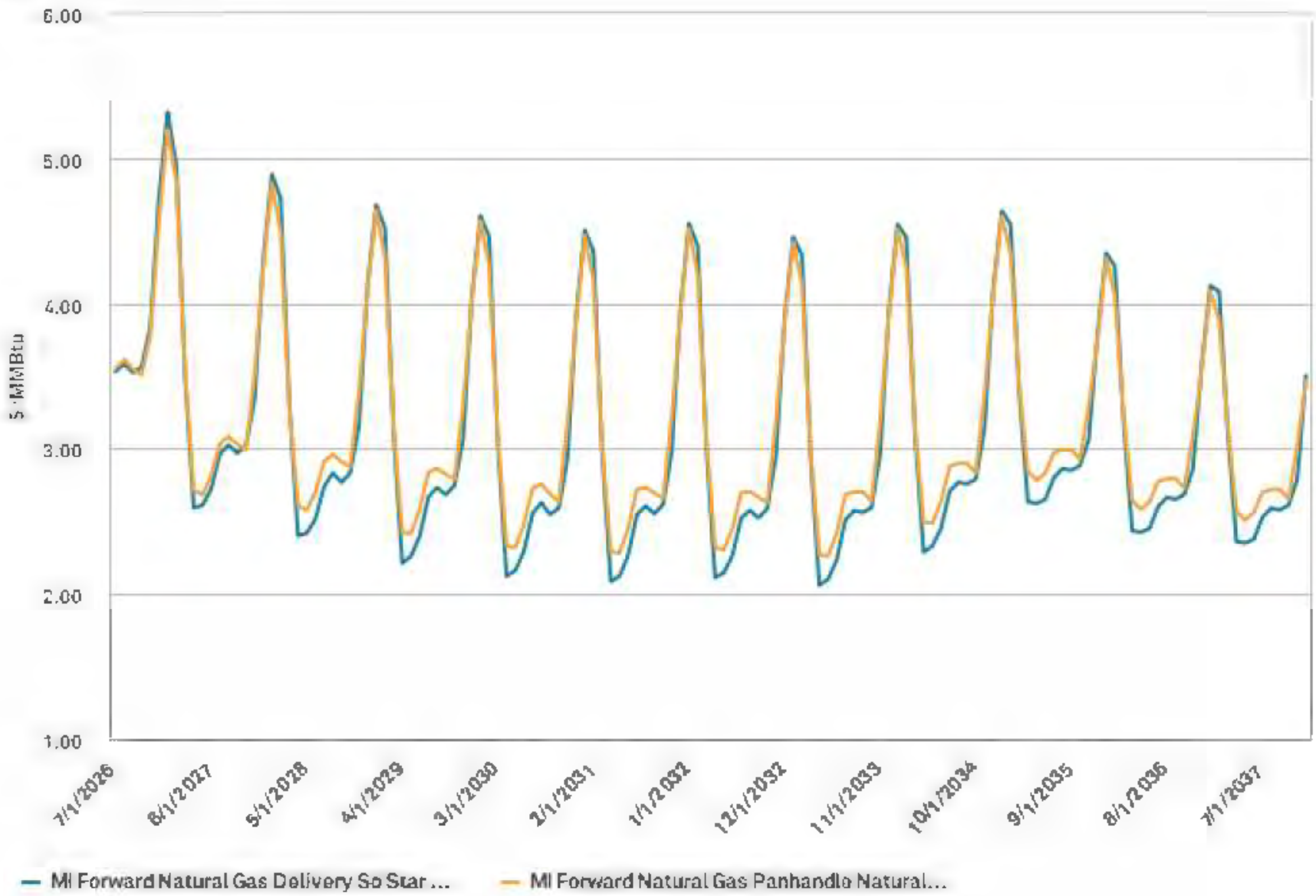
S&P Capital IQ PRO

STAFF EXHIBIT JTG-15

Commodity Charting

Series Type:	Forward
Source:	MI Forward
Location:	Panhandle, Delivery So Star
Instrument:	Natural Gas Full Value Monthly
Forward Term:	
Forward Strip As Of:	03/12/2025
Measure:	Price/Value
Add Series:	MI Forward Natural Gas Delivery So Star Natural Gas Full Value Monthly (Price/Value) - As Of: 2025-03-12, MI Forward Natural Gas Panhandle Natural Gas Full Value Monthly (Price/Value) - As Of: 2025-03-12
Historical Period:	1 Year
Time Zone:	Eastern Time (US & Canada)
Chart Type:	Line
Forward Term Duration:	20 Years

Chart



Data

DATE	MI FORWARD NATURAL GAS DELIVERY SO STAR NATURAL GAS FULL VALUE MONTHLY (PRICE/VALUE) - AS OF: 2025-03-12	MI FORWARD NATURAL GAS PANHANDLE NATURAL GAS FULL VALUE MONTHLY (PRICE/VALUE) - AS OF: 2025-03-12

DATE	MI FORWARD NATURAL GAS DELIVERY SO STAR NATURAL GAS FULL VALUE MONTHLY (PRICE/VALUE) - AS OF: 2025-03-12	MI FORWARD NATURAL GAS PANHANDLE NATURAL GAS FULL VALUE MONTHLY (PRICE/VALUE) - AS OF: 2025-03-12
7/1/2026	3.5300	3.5520
8/1/2026	3.5830	3.6120
9/1/2026	3.5230	3.5490
10/1/2026	3.5620	3.5070
11/1/2026	3.8370	3.7790
12/1/2026	4.7320	4.5730
1/1/2027	5.3140	5.1930
2/1/2027	4.9440	4.8330
3/1/2027	3.5020	3.5270
4/1/2027	2.5930	2.7150
5/1/2027	2.6100	2.6820
6/1/2027	2.7210	2.8100
7/1/2027	2.9640	3.0310
8/1/2027	3.0250	3.0820
9/1/2027	2.9690	3.0290
10/1/2027	3.0210	2.9930
11/1/2027	3.3380	3.5100
12/1/2027	4.3010	4.2480
1/1/2028	4.8860	4.8230
2/1/2028	4.7220	4.4890
3/1/2028	3.3120	3.2760
4/1/2028	2.4010	2.6090
5/1/2028	2.4190	2.5770
6/1/2028	2.5160	2.6990
7/1/2028	2.7390	2.9120
8/1/2028	2.8320	2.9610
9/1/2028	2.7680	2.9100
10/1/2028	2.8320	2.8760
11/1/2028	3.1490	3.3780
12/1/2028	4.1210	4.0880

Commodity Charting

DATE	MI FORWARD NATURAL GAS DELIVERY SO STAR NATURAL GAS FULL VALUE MONTHLY (PRICE/VALUE) - AS OF: 2025-03-12	MI FORWARD NATURAL GAS PANHANDLE NATURAL GAS FULL VALUE MONTHLY (PRICE/VALUE) - AS OF: 2025-03-12
1/1/2029	4.6760	4.6410
2/1/2029	4.5210	4.3200
3/1/2029	3.1090	3.1530
4/1/2029	2.2120	2.4200
5/1/2029	2.2600	2.4180
6/1/2029	2.3960	2.5810
7/1/2029	2.6660	2.8390
8/1/2029	2.7330	2.8620
9/1/2029	2.6830	2.8250
10/1/2029	2.7450	2.7890
11/1/2029	3.0650	3.2940
12/1/2029	4.0420	4.0090
1/1/2030	4.6010	4.5660
2/1/2030	4.4560	4.2550
3/1/2030	3.0330	3.0770
4/1/2030	2.1230	2.3310
5/1/2030	2.1620	2.3200
6/1/2030	2.2940	2.4770
7/1/2030	2.5560	2.7290
8/1/2030	2.6280	2.7570
9/1/2030	2.5470	2.6890
10/1/2030	2.5900	2.6340
11/1/2030	2.9280	3.1570
12/1/2030	3.9120	3.8790
1/1/2031	4.5030	4.4680
2/1/2031	4.3600	4.1590
3/1/2031	2.9700	3.0140
4/1/2031	2.0860	2.2940
5/1/2031	2.1230	2.2810
6/1/2031	2.2690	2.4520

Commodity Charting

DATE	MI FORWARD NATURAL GAS DELIVERY SO STAR NATURAL GAS FULL VALUE MONTHLY (PRICE/VALUE) - AS OF: 2025-03-12	MI FORWARD NATURAL GAS PANHANDLE NATURAL GAS FULL VALUE MONTHLY (PRICE/VALUE) - AS OF: 2025-03-12
7/1/2031	2.5460	2.7190
8/1/2031	2.6050	2.7340
9/1/2031	2.5530	2.6950
10/1/2031	2.6140	2.6580
11/1/2031	2.9730	3.2020
12/1/2031	3.9530	3.9200
1/1/2032	4.5480	4.5130
2/1/2032	4.3940	4.1930
3/1/2032	3.0120	3.0560
4/1/2032	2.1130	2.3210
5/1/2032	2.1450	2.3030
6/1/2032	2.2660	2.4490
7/1/2032	2.5230	2.6960
8/1/2032	2.5760	2.7050
9/1/2032	2.5240	2.6660
10/1/2032	2.5860	2.6300
11/1/2032	2.9480	3.1770
12/1/2032	3.8950	3.8620
1/1/2033	4.4550	4.4200
2/1/2033	4.3310	4.1300
3/1/2033	2.9390	2.9830
4/1/2033	2.0600	2.2680
5/1/2033	2.1020	2.2600
6/1/2033	2.2350	2.4180
7/1/2033	2.5120	2.6850
8/1/2033	2.5730	2.7020
9/1/2033	2.5610	2.7030
10/1/2033	2.5940	2.6380
11/1/2033	2.9610	3.1900
12/1/2033	3.9460	3.9150

Commodity Charting

DATE	MI FORWARD NATURAL GAS DELIVERY SO STAR NATURAL GAS FULL VALUE MONTHLY (PRICE/VALUE) - AS OF: 2025-03-12	MI FORWARD NATURAL GAS PANHANDLE NATURAL GAS FULL VALUE MONTHLY (PRICE/VALUE) - AS OF: 2025-03-12
1/1/2034	4.5430	4.5080
2/1/2034	4.4540	4.2530
3/1/2034	3.1170	3.1610
4/1/2034	2.2880	2.4960
5/1/2034	2.3300	2.4880
6/1/2034	2.4510	2.6340
7/1/2034	2.7080	2.8810
8/1/2034	2.7690	2.8980
9/1/2034	2.7570	2.8990
10/1/2034	2.7900	2.8340
11/1/2034	3.1370	3.3660
12/1/2034	4.0940	4.0610
1/1/2035	4.6340	4.5990
2/1/2035	4.5450	4.3440
3/1/2035	3.3930	3.4370
4/1/2035	2.6340	2.8420
5/1/2035	2.6240	2.7820
6/1/2035	2.6500	2.8330
7/1/2035	2.8020	2.9750
8/1/2035	2.8630	2.9920
9/1/2035	2.8510	2.9930
10/1/2035	2.8840	2.9280
11/1/2035	3.0630	3.2920
12/1/2035	3.7750	3.7420
1/1/2036	4.3450	4.3100
2/1/2036	4.2560	4.0550
3/1/2036	3.1940	3.2380
4/1/2036	2.4350	2.6430
5/1/2036	2.4250	2.5830
6/1/2036	2.4510	2.6340

DATE	MI FORWARD NATURAL GAS DELIVERY SO STAR NATURAL GAS FULL VALUE MONTHLY (PRICE/VALUE) - AS OF: 2025-03-12	MI FORWARD NATURAL GAS PANHANDLE NATURAL GAS FULL VALUE MONTHLY (PRICE/VALUE) - AS OF: 2025-03-12
7/1/2036	2.6030	2.7760
8/1/2036	2.6640	2.7930
9/1/2036	2.6520	2.7940
10/1/2036	2.6850	2.7290
11/1/2036	2.8640	3.0930
12/1/2036	3.5760	3.5430
1/1/2037	4.1210	4.0860
2/1/2037	4.0820	3.8810
3/1/2037	3.1200	3.1640
4/1/2037	2.3610	2.5690
5/1/2037	2.3510	2.5090
6/1/2037	2.3770	2.5600
7/1/2037	2.5290	2.7020
8/1/2037	2.5900	2.7190
9/1/2037	2.5760	2.7200
10/1/2037	2.6110	2.6550
11/1/2037	2.7900	3.0190
12/1/2037	3.5020	3.4690

The MI Forward natural gas curve models monthly forward values for regional gas hubs based on observed monthly quotes and forward seasonal basis values, to facilitate monthly forward basis and full value review.

The MI Forward power curve models monthly forward values for regional power hubs based on existing monthly forward values and forward calendar year quotes.

NYMEX and CME Clearport market data provided by DTN.

ISO-sourced hourly and sub-hourly data is limited to one year of history for display. Additional history may be accessed by exporting selected data to Excel as SNL Formulas and adjusting the start/end history paramaters.

ISO-sourced Alberta and Ontario Canadian power prices are reported in C$/MWh. U.S. power locations are reported in US$/MWh.

Commodity Charting

Only two different units of measure may be charted at the same time, i.e. energy prices with two different currencies or an energy price and an anergy load.

STATE OF KANSAS)
) ss.
COUNTY OF SHAWNEE)

VERIFICATION

Justin T. Grady, being duly sworn upon his oath deposes and states that he is Deputy Director of the Utilities Division of the Kansas Corporation Commission of the State of Kansas, that he has read and is familiar with the foregoing *Direct Testimony,* and attests that the statements contained therein are true and correct to the best of his knowledge, information and belief.

Justin T. Grady
Deputy Director of the Utilities Division
State Corporation Commission of the
State of Kansas

Subscribed and sworn to before me this 11 day of March, 2025.

Notary Public

My Appointment Expires: 4/28/25

NOTARY PUBLIC - State of Kansas
ANN M. MURPHY
My Appt. Expires 4/28/25

CERTIFICATE OF SERVICE

25-EKCE-207-PRE

I, the undersigned, certify that a true and correct copy of the above and foregoing Direct Testimony of Justin Grady was served via electronic service this 14th day of March, 2025, to the following:

JAMES G. FLAHERTY, ATTORNEY
ANDERSON & BYRD, L.L.P.
216 S HICKORY
PO BOX 17
OTTAWA, KS 66067-0017
jflaherty@andersonbyrd.com

SHELLY M BASS, SENIOR ATTORNEY
ATMOS ENERGY CORPORATION
5430 LBJ FREEWAY
1800 THREE LINCOLN CENTRE
DALLAS, TX 75240
shelly.bass@atmosenergy.com

KATHLEEN R OCANAS, DIVISION VP OF RATES & REGULATORY AFFAIRS
ATMOS ENERGY CORPORATION
25090 W 110TH TERR
OLATHE, KS 66061
kathleen.ocanas@atmosenergy.com

JOSEPH R. ASTRAB, CONSUMER COUNSEL
CITIZENS' UTILITY RATEPAYER BOARD
1500 SW ARROWHEAD RD
TOPEKA, KS 66604
joseph.astrab@ks.gov

TODD E. LOVE, ATTORNEY
CITIZENS' UTILITY RATEPAYER BOARD
1500 SW ARROWHEAD RD
TOPEKA, KS 66604
todd.love@ks.gov

SHONDA RABB
CITIZENS' UTILITY RATEPAYER BOARD
1500 SW ARROWHEAD RD
TOPEKA, KS 66604
shonda.rabb@ks.gov

DELLA SMITH
CITIZENS' UTILITY RATEPAYER BOARD
1500 SW ARROWHEAD RD
TOPEKA, KS 66604
della.smith@ks.gov

Randall F. Larkin, ATTORNEY
CITY OF LAWRENCE
PO Box 708
Lawrence, KS 66044
rlarkin@lawrenceks.org

Brandon McGuire, ASST. CITY MANAGER
CITY OF LAWRENCE
PO Box 708
Lawrence, KS 66044
bmcguire@lawrenceks.org

Kathy Richardson, SUSTAINABILITY DIRECTOR
CITY OF LAWRENCE
PO Box 708
Lawrence, KS 66044
krichardson@lawrenceks.org

CERTIFICATE OF SERVICE

25-EKCE-207-PRE

TONI WHEELER, DIRECTOR, LEGAL SERVICES DEPT.
CITY OF LAWRENCE
CITY HALL
6 EAST SIXTH ST
LAWRENCE, KS 66044
twheeler@lawrenceks.org

DOROTHY BARNETT
CLIMATE & ENERGY PROJECT
PO BOX 1858
HUTCHINSON, KS 67504-1858
barnett@climateandenergy.org

CATHRYN J. DINGES, SR DIRECTOR & REGULATORY AFFAIRS COUNSEL
EVERGY KANSAS CENTRAL, INC
818 S KANSAS AVE
PO BOX 889
TOPEKA, KS 66601-0889
cathy.dinges@evergy.com

LESLIE WINES, SR. EXEC. ADMIN. ASST.
EVERGY KANSAS CENTRAL, INC
818 S KANSAS AVE
PO BOX 889
TOPEKA, KS 66601-0889
leslie.wines@evergy.com

DANIEL J BULLER, ATTORNEY
FOULSTON SIEFKIN LLP
7500 COLLEGE BOULEVARD, STE 1400
OVERLAND PARK, KS 66201-4041
dbuller@foulston.com

MOLLY E MORGAN, ATTORNEY
FOULSTON SIEFKIN LLP
1551 N. Waterfront Parkway
Suite 100
Wichita, KS 67206
mmorgan@foulston.com

SARAH C. OTTO
FOULSTON SIEFKIN LLP
7500 COLLEGE BOULEVARD, STE 1400
OVERLAND PARK, KS 66201-4041
sotto@foulston.com

LEE M SMITHYMAN, ATTORNEY
FOULSTON SIEFKIN LLP
7500 COLLEGE BOULEVARD, STE 1400
OVERLAND PARK, KS 66201-4041
lsmithyman@foulston.com

C. EDWARD WATSON II., ATTORNEY
FOULSTON SIEFKIN LLP
1551 N WATERFRONT PKWY STE 100
WICHITA, KS 67206-4466
cewatson@foulston.com

JAMES P ZAKOURA, ATTORNEY
FOULSTON SIEFKIN LLP
7500 COLLEGE BOULEVARD, STE 1400
OVERLAND PARK, KS 66201-4041
jzakoura@foulston.com

Kevin M Fowler, COUNSEL
Frieden & Forbes, LLP
1414 SW Ashworth Place Ste 201
Topeka, KS 66604
kfowler@fflawllp.com

Constance Chan, SENIOR CATEGORY MANAGER - ELECTRICITY & BUSINESS TRAVEL
HF SINCLAIR EL DORADO REFINING LLC
2323 Victory Ave. Ste 1400
Dalla, TX 75219
constance.chan@hfsinclair.com

CERTIFICATE OF SERVICE

25-EKCE-207-PRE

Jon Lindsey, CORPORATE COUNSEL
HF SINCLAIR EL DORADO REFINING LLC
550 E. South Temple
Salt Lake City, UT 84102
jon.lindsey@hfsinclair.com

BRIAN G. FEDOTIN, GENERAL COUNSEL
KANSAS CORPORATION COMMISSION
1500 SW ARROWHEAD RD
TOPEKA, KS 66604
brian.fedotin@ks.gov

JUSTIN GRADY, CHIEF OF REVENUE REQUIREMENTS, COST OF SERVICE & FINANCE
KANSAS CORPORATION COMMISSION
1500 SW ARROWHEAD RD
TOPEKA, KS 66604
justin.grady@ks.gov

PATRICK HURLEY, CHIEF LITIGATION COUNSEL
KANSAS CORPORATION COMMISSION
1500 SW ARROWHEAD RD
TOPEKA, KS 66604
patrick.hurley@ks.gov

CARLY MASENTHIN, LITIGATION COUNSEL
KANSAS CORPORATION COMMISSION
1500 SW ARROWHEAD RD
TOPEKA, KS 66604
carly.masenthin@ks.gov

JANET BUCHANAN, DIRECTOR OF RATES & REGULATORY
KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
7421 W 129TH STREET
OVERLAND PARK, KS 66213
janet.buchanan@onegas.com

LORNA EATON, MANAGER OF RATES AND REGULATORY AFFAIRS
KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
7421 W 129TH STREET
OVERLAND PARK, KS 66213
lorna.eaton@onegas.com

ROBERT E. VINCENT, MANAGING ATTORNEY
KANSAS GAS SERVICE, A DIVISION OF ONE GAS, INC.
7421 W. 129TH STREET
OVERLAND PARK, KS 66213
robert.vincent@onegas.com

PAUL MAHLBERG, GENERAL MANAGER
KANSAS MUNICIPAL ENERGY AGENCY
6300 W 95TH ST
OVERLAND PARK, KS 66212-1431
mahlberg@kmea.com

TERRI J PEMBERTON, GENERAL COUNSEL
KANSAS MUNICIPAL ENERGY AGENCY
6300 W 95TH ST
OVERLAND PARK, KS 66212-1431
pemberton@kmea.com

DARREN PRINCE, MANAGER, REGULATORY & RATES
KANSAS MUNICIPAL ENERGY AGENCY
6300 W 95TH ST
OVERLAND PARK, KS 66212-1431
prince@kmea.com

JAMES GING, DIRECTOR ENGINEERING SERVICES
KANSAS POWER POOL
100 N BROADWAY STE L110
WICHITA, KS 67202
jging@kpp.agency

CERTIFICATE OF SERVICE

25-EKCE-207-PRE

COLIN HANSEN, CEO/GENERAL MANAGER
KANSAS POWER POOL
100 N BROADWAY STE L110
WICHITA, KS 67202
chansen@kpp.agency

LARRY HOLLOWAY, ASST GEN MGR OPERATIONS
KANSAS POWER POOL
100 N BROADWAY STE L110
WICHITA, KS 67202
lholloway@kpp.agency

ALISSA GREENWALD, ATTORNEY
KEYES & FOX LLP
1580 LINCOLN STREET STE 1105
DENVER, CO 80203
agreenwald@keyesfox.com

JASON KEYES, PARTNER
KEYES & FOX LLP
580 CALIFORNIA ST 12TH FLOOR
SAN FRANCISCO, CA 94104
jkeyes@keyesfox.com

PATRICK PARKE, CEO
MIDWEST ENERGY, INC.
1330 Canterbury Rd
PO Box 898
Hays, KS 67601-0898
patparke@mwenergy.com

AARON ROME, VP OF ENERGY SUPPLY
MIDWEST ENERGY, INC.
1330 CANTERBURY DRIVE
PO BOX 898
HAYS, KS 67601-0898
arome@mwenergy.com

VALERIE SMITH, ADMINISTRATIVE ASSISTANT
MORRIS LAING EVANS BROCK & KENNEDY
800 SW JACKSON
SUITE 1310
TOPEKA, KS 66612-1216
vsmith@morrislaing.com

TREVOR WOHLFORD, ATTORNEY
MORRIS LAING EVANS BROCK & KENNEDY
800 SW JACKSON
SUITE 1310
TOPEKA, KS 66612-1216
twohlford@morrislaing.com

GLENDA CAFER, MORRIS LAING LAW FIRM
MORRIS LAING EVANS BROCK & KENNEDY CHTD
800 SW JACKSON STE 1310
TOPEKA, KS 66612-1216
gcafer@morrislaing.com

RITA LOWE, PARALEGAL
MORRIS LAING EVANS BROCK & KENNEDY CHTD
300 N MEAD STE 200
WICHITA, KS 67202-2745
rlowe@morrislaing.com

WILL B. WOHLFORD, ATTORNEY
MORRIS LAING EVANS BROCK & KENNEDY CHTD
300 N MEAD STE 200
WICHITA, KS 67202-2745
wwohlford@morrislaing.com

ASHOK GUPTA, EXPERT
NATIONAL RESOURCES DEFENSE COUNCIL
20 N WACKER DRIVE SUITE 1600
CHICAGO, IL 60606
agupta@nrdc.org

CERTIFICATE OF SERVICE

25-EKCE-207-PRE

DAN BRUER, EXECUTIVE DIRECTOR
NEW ENERGY ECONOMICS
1390 YELLOW PINE AVE
BOULDER, CO 80305
dan.bruer@newenergyeconomics.org

TIM OPITZ
OPITZ LAW FIRM, LLC
308 E. HIGH STREET
SUITE B101
JEFFERSON CITY, MO 65101
tim.opitz@opitzlawfirm.com

ANNE E. CALLENBACH, ATTORNEY
POLSINELLI PC
900 W 48TH PLACE STE 900
KANSAS CITY, MO 64112
acallenbach@polsinelli.com

FRANK A. CARO, JR., ATTORNEY
POLSINELLI PC
900 W 48TH PLACE STE 900
KANSAS CITY, MO 64112
fcaro@polsinelli.com

JARED R. JEVONS, ATTORNEY
POLSINELLI PC
900 W 48TH PLACE STE 900
KANSAS CITY, MO 64112
jjevons@polsinelli.com

Greg Wright
Priority Power Mgt.
12512 Augusta Dr
Kansas City, KS 66109
gwright@prioritypower.com

JAMES OWEN, COUNSEL
RENEW MISSOURI ADVOCATES
915 E ASH STREET
COLUMBIA, MO 65201
james@renewmo.org

TIMOTHY J LAUGHLIN, ATTORNEY
SCHOONOVER & MORIARTY, LLC
130 N. CHERRY STREET, STE 300
OLATHE, KS 66061
tlaughlin@schoonoverlawfirm.com

Peggy A. Trent, CHIEF COUNTY COUNSELOR
The Board of County Commissioners of Johnson County
111 S. Cherry Ste 3200
Olathe, KS 66061
peg.trent@jocogov.org

ROBERT R. TITUS
TITUS LAW FIRM, LLC
7304 W. 130th St.
Suite 190
Overland Park, KS 66213
rob@tituslawkc.com

J.T. KLAUS, ATTORNEY
TRIPLETT, WOOLF & GARRETSON, LLC
2959 N ROCK RD STE 300
WICHITA, KS 67226
jtklaus@twgfirm.com

KACEY S MAYES, ATTORNEY
TRIPLETT, WOOLF & GARRETSON, LLC
2959 N ROCK RD STE 300
WICHITA, KS 67226
ksmayes@twgfirm.com

CERTIFICATE OF SERVICE

25-EKCE-207-PRE

TIMOTHY E. MCKEE, ATTORNEY
TRIPLETT, WOOLF & GARRETSON, LLC
2959 N ROCK RD STE 300
WICHITA, KS 67226
temckee@twgfirm.com

JOHN J. MCNUTT, GENERAL ATTORNEY
U.S. ARMY LEGAL SERVICES AGENCY
REGULATORY LAW OFFICE
9275 GUNSTON RD., STE. 1300
FORT BELVOIR, VA 22060-5546
john.j.mcnutt.civ@army.mil

DAN LAWRENCE, GENERAL COUNSEL - USD 259
UNIFIED SCHOOL DISTRICT 259
903 S EDGEMOOR RM 113
WICHITA, KS 67218
dlawrence@usd259.net

KEVIN K. LACHANCE, CONTRACT LAW ATTORNEY
UNITED STATES DEPARTMENT OF DEFENSE
ADMIN & CIVIL LAW DIVISION
OFFICE OF STAFF JUDGE ADVOCATE
FORT RILEY, KS 66442
kevin.k.lachance.civ@army.mil

Ann Murphy

Ann Murphy