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Filed Date: 11/02/2021
State Corporation Commission
of Kansas

BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

| | | |
|---|---|---|
| In the Matter of the Capital Plan Compliance Docket for Kansas City Power & Light Company and Westar Energy, Inc. Pursuant to the Commission's Order in Docket No. 18-KCPE-095-MER | ) ) ) ) ) ) | Docket No. 19-KCPE-096-CPL |

**REPORT OF THE COUNCIL FOR THE NEW ENERGY ECONOMICS**

COMES NOW, The Council for New Energy Economics ("NEE") and respectfully files the attached Report addressing the triennial resource planning filing of Evergy Metro Inc., d/b/a Evergy Kansas Metro; and Evergy Kansas Central, Inc. and Evergy Kansas South, Inc., collectively d/b/a Evergy Kansas Central (together, "Evergy") in the above-referenced case (the "Evergy IRP Proceeding") pursuant to the Integrated Resource Planning Framework ("Framework") adopted in this Proceeding. In support of its Report, NEE states as follows:

1. NEE is a non-profit organization committed to helping utilities and energy decision-makers navigate rapidly evolving utility industry economics using neutral data and analysis. NEE's mission is to present policy, utility and stakeholder energy decision-makers with complex utility system modeling analysis to help determine the most cost-effective path forward for the deployment of energy resources. The Kansas Corporation Commission ("Commission") granted NEE's application to intervene in the Evergy IRP Proceeding on November 3, 2020.

2. NEE engaged Energy Futures Group ("EFG") to evaluate the economic retirement dates of Evergy's generating units and to compare Evergy's Integrated Resource Plan ("IRP") Preferred Plans to an optimized plan using EFG's modeling analysis. EFG

has deep experience participating in state IRP regulatory proceedings. For example, Anna Sommer, principal at EFG, has provided expert testimony in front of utility commissions in Michigan, Minnesota, Montana, New Mexico, North Carolina, Puerto Rico, South Carolina, and South Dakota. EFG's experience includes capacity expansion and production cost modeling, scenario and sensitivity construction, modeling of supply and demand resources, and review of forecast inputs, such as fuel prices, wholesale market prices, and load forecasts. EFG also has experience reviewing modeling performed using numerous models including Aurora, Capacity Expansion Model, EnCompass, PLEXOS, PowerSimm, PROSYM, PROMOD, SERVM, Strategist, and System Optimizer.

3. For the Evergy IRP Proceeding, EFG used EnCompass modeling software which includes several features that make it superior to the MIDAS software used by Evergy. Most notably, the MIDAS software requires Evergy to hand select portfolios and then simulate dispatch of those plans on a 8760 hour per hear basis in a production cost model. By contract, EnCompass features capacity expansion optimization capability, which allows the user to develop optimal generation portfolios before simulating dispatch in a production cost model. The vast majority of utilities of Evergy's size conducting IRP modeling use a model capable of capacity expansion optimization.

4. The lack of capacity expansion optimization in Evergy's modeling results in a Deficiency in Evergy's compliance with the underlying policy objective of the Framework.

5. As further detailed in the attached Report, NEE has identified several other Concerns relating to Evergy's compliance with the Framework. These include:

a. Evergy's use of critical factor and risk analysis methodology used to capture risk factors.

b. Evergy's apparent failure to model any Alternate Resource Plans that contained new battery storage or solar hybrid resources.

c. Evergy's cost assumptions for new solar, wind, and battery storage resources are based on out-of-date data.

d. Evergy's cost assumptions for new solar resources do not include monetization of the Investment Tax Credit ("ITC").

e. Evergy's failure to evaluate achievable and beneficial levels of demand side management.

f. Evergy's inadequate modeling of extreme weather conditions.

6. The attached Report provides suggested remedies for the above listed Deficiencies and Concerns.

7. Using superior modeling software and making limited but appropriate modifications to certain inputs, NEE developed a Preferred Plan that saves Evergy customers money on a net present value revenue requirement basis.

8. WHEREFORE, NEE respectfully requests that the Commission accept this Report. NEE also requests all other relief to which it is entitled.

Respectfully submitted,

By: *<u>/s/Andrew O. Schulte</u>*

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The undersigned hereby certifies that a true and correct copy of the above and foregoing pleading was emailed on November 1 and 2, 2021, to:

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*/s/Andrew O. Schulte*
Andrew O. Schulte

**VERIFICATION**

STATE OF MISSOURI )
) ss.
COUNTY OF JACKSON )

I, Andrew O. Schulte, being duly sworn, on oath state that I am counsel to the Council for the New Energy Economics, that I have read the foregoing pleading and know the contents thereof, and that the facts set forth therein are true and correct to the best of my knowledge and belief.

By: Andrew O. Schulte
Andrew O. Schulte

The foregoing pleading was subscribed and sworn to before me this 2nd day of November, 2021.

JULIE ANN LOWREY
NOTARY PUBLIC-NOTARY SEAL
STATE OF MISSOURI
JACKSON COUNTY
MY COMMISSION EXPIRES 7/29/2024
COMMISSION # 20401259

Julie Ann Lowrey
Notary Public

My Commission Expires:
7/29/2024

# Evaluation of Triennial Resource Planning Filing of Evergy Metro and Evergy Kansas Central

Prepared by:

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Prepared for:

**The Council for the New Energy Economics**

**November 2021**

## Acknowledgements

We are grateful for the advice given to us during the course of this work by Derek Stenclik, Matt Richwine, and Jim Geddis of Telos Energy, Becky Li, David Posner, and Ben Surrier of Rocky Mountain Institute, Will Gorrissen and Josh Keeling of Cadeo Group, Michael Milligan of Milligan Grid Solutions, and Jay Caspary of Grid Strategies, LLC.

All errors and omissions are the responsibility of the authors.

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# 1 Summary

The Council for the New Energy Economics ("NEE") engaged Energy Futures Group ("EFG") to evaluate the economic retirement dates of Evergy's generating units and to compare Evergy's Integrated Resource Plan ("IRP") Preferred Plans to an optimized plan for each of Evergy's operating companies.

The following sections discuss the results of that modeling and the steps that EFG took to create an EnCompass database for each of Evergy's operating companies to perform capacity expansion and production cost modeling. Our modeling approach was as follows:

1. Optimize retirement dates for Evergy's existing plants;
2. Evaluate replacement capacity based on those optimized retirement dates;
3. Evaluate the Missouri Energy Efficiency Investment Act ("MEEIA") level of energy efficiency savings for Missouri and Kansas service territories; and
4. Evaluate NEE's preferred plan for Evergy Metro under Evergy's Extreme Temperature scenario.

Our findings are that the EnCompass modeling described in this report demonstrate that a portfolio of renewable and storage resources with limited new fossil generation has:

1. Significantly lower costs than the Evergy Metro Preferred Plan;
2. Modestly lower costs than the Evergy Kansas Central Preferred Plan;
3. Much greater $CO_2$ emission reductions;
4. Hundred of millions of dollars in savings from securitization; and
5. Additional energy efficiency modestly reduces system cost.

Our report also summarizes our assessment of Evergy's IRP and the deficiencies and concerns we have found with the IRP[1]. Table 1 provides a summary of areas of concern and deficiency we

[1] The Kansas IRP Framework directs Parties to "file a report … that identifies any deficiencies in Evergy's compliance with the provisions of this framework, any major deficiencies in the methodologies or analyses required to be performed by this framework and any other deficiencies which, in its limited review, the Parties determine would cause Evergy's resource acquisition strategy to fail to meet the requirements identified in this framework." This definition of "deficiency" is equivalent to the definition of "deficiency" found in Missouri's Electric Utility Resource Planning Rules ("Missouri Rules") at 20 CSR 4240-022.020(9). The Missouri Rules also define "concern" as "concerns with the electric utility's compliance with the provisions of [the Missouri Rules], any major concerns with the methodologies or analyses required to be performed by [the Missouri Rules], and anything that, while not rising to the level of a deficiency, may prevent the electric utility's resource acquisition

have identified in the IRPs that Evergy filed. We discuss our recommendations related to these deficiencies and concerns, in addition to items related to Demand Side Management ("DSM") in more detail in Section 7 of this report.

**Table 1. Deficiencies and Concerns for Evergy's Kansas IRP Filing**

| IRP Framework Topic | Deficiency or Concern | Recommendation |
|---|---|---|
| Resource modeling identifies the portfolio of resources that meets customer requirements at the lowest reasonable cost given an uncertain future | Deficiency | Utilize capacity expansion and production cost modeling to ensure minimization of costs |
| The optimal portfolio of resources will vary based on modeling assumptions | Concern | Utilize market pricing from RFPs or the NREL ATB if market price data is not available |
| The optimal portfolio of resources will vary based on modeling assumptions; Medium-Run Future Expectations: Cost-Effective Electric Storage | Deficiency | Include solar hybrid resources and battery storage technologies in Alternate Resource Plans |
| The optimal portfolio of resources will vary based on modeling assumptions | Deficiency | Assume monetization of the ITC to fairly evaluate solar and paired storage |

strategy from effectively fulfilling the objectives of [the Missouri Rules]." Although the Kansas IRP Framework does not expressly direct Parties to address "concerns," for the benefit of the Kansas Corporation Commission, stakeholders, and the public generally, this Report includes "concerns" regarding Evergy's compliance with the Kansas IRP Framework, based on an equivalent application of Missouri's definition of "concerns."

| | | |
|---|---|---|
| Part of the purpose of the IRP Process is to provide (l) resource modeling that identifies the portfolio of resources that meets customer requirements at the lowest reasonable cost given an uncertain future, and (2) to provide an optimal portfolio that is flexible and robust as determined by input sensitivity analyses and contingent scenario analyses. | Concern | Utilize scenario and sensitivity modeling to test critical factors |
| Medium-Run Futures Expectations: Energy Efficiency Alternative Scenario Analysis and Energy Efficiency Engineering Improvements | Deficiency | Evaluate the cost-effectiveness of all levels of DSM contained in the Company's MO Market Potential Study and evaluate energy efficiency programs specific to the Company's Kansas service territories at multiple savings levels |
| "[W]hat-if' contingency analysis needs to be conducted to determine how flexible and robust each supply option is | Concern | Evaluate supply and demand-side resource performance under the same meteorological conditions that underpin the extreme weather load forecast |
| If Evergy determines that circumstances have changed so that the preferred resource plan is no longer appropriate for any reason(s), it shall notify the Commission in writing within sixty (60) days of its determination. If Evergy decides to implement | Deficiency | Evergy notified the Commission of a change in its preferred plan in a separate docket (and submitted a waiver in this docket) but without any modeling to support that change. Indeed, Evergy's Director of Long-Term Planning Kayla Messamore said in testimony in that docket that, "Analysis related to trade offs between retiring LEC Unit 5 and transitioning it to gas operations will be included in future IRP filings."[2] |

[2] Direct Testimony of Kayla Messamore in Docket No.22-EKCE-141-PRE, page 23, lines 11 – 13. (Sept. 20, 2021).

| | | |
|---|---|---|
| any material changes to its preferred resource plan, it shall file supporting documents relating to the change for review in advance of its next regularly scheduled compliance filing. | | |

# 2 EnCompass Modeling

Evergy developed its Alternate Resource Plans by hand selecting portfolios and then simulating dispatch of those plans on an 8760 hour per year basis in a production costing model called MIDAS. We have several concerns about the use of MIDAS including its inability to select an optimal plan, its likely inability to model storage resources, its inability to model paired battery storage and hybrid storage resources, and a lack of vendor support for the model.

In one of Evergy's Kansas stakeholder workshops, Evergy referred to the process of hand developing capacity expansion plans as a "hunt and peck" exercise. Developing hundreds of portfolios by hand is extremely time intensive and it does not guarantee that optimal plans are being developed. Furthermore, this means that Evergy had no way to thoroughly evaluate the economic retirement dates of its coal fleet.

EFG's approach to modeling Evergy's system was to utilize a software called EnCompass[3], which is capable of developing optimized capacity expansion plans and then redispatching those plans in hourly production cost simulations. The model reports out the present value of revenue requirements ("PVRR"), which allows plans to be compared on a cost basis. By using EnCompass, we were able to allow the model to optimally select retirement dates and replacement resources for Evergy's coal plants. We employed a three-step modeling approach that looked at performing capacity expansion to determine optimized retirement dates across the Metro and Kansas Central operating companies since a number of generators are co-owned by two or more Evergy operating companies. We then evaluated those retirement dates and fixed them for the step two modeling, where we performed capacity expansion and production cost modeling based on those fixed retirement dates. Step three involved rerunning Evergy's Preferred Plan through the EnCompass model so that the NEE Preferred Plans could be compared to Evergy's Preferred Plans on an apples-to-apples cost basis.

[3] Anchor Power Solutions is the vendor of EnCompass. EnCompass is used by utilities across North America including Public Service Company of New Mexico, Xcel Energy, Minnesota Power, Otter Tail Power, Great River Energy, the Tennessee Valley Authority, DTE Electric, AES Indiana, Duke Energy, and Kentucky Municipal Energy Agency.

Evergy's methodology for evaluating and ranking alternate resource plans includes assessing the Net Present Value of Revenue Requirements ("NPVRR") results for individual scenarios in addition to the "expected" value of the NPVRR across all scenarios. Evergy applies an endpoint probability for several different critical factors, which Evergy has identified as the load forecast, natural gas, and $CO_2$ prices. Table 2 shows the critical uncertain factors along with the probability distributions assigned to them. We have several concerns about the application of this methodology and how the endpoint probabilities were developed which we discuss in Section 7.1.2. Therefore, instead of modeling all 27 endpoint combinations (3 load x 3 natural gas x 3 $CO_2$ price), we used the load, natural gas, and $CO_2$ forecasts where the endpoint probability was assigned with the highest probability for each of the critical factors, i.e. the mid point forecasts of those forecasts.

**Table 2. Critical Uncertain Factor Probabilities[4]**

| | Low | Mid | High |
|---|---|---|---|
| Load Growth | 35% | 50% | 15% |
| Natural Gas | 35% | 50% | 15% |
| $CO_2$ Price | 20% | 60% | 20% |

It is our understanding that Evergy optimized each of its operating companies individually[5], and then aggregated the results on a company basis. Our modeling performed capacity expansion and production cost modeling for each of the operating companies. The EnCompass model was run for the planning period of 2021 to 2040.

The following sections discuss the steps that EFG took to create an EnCompass database for each of Evergy's operating companies to perform capacity expansion and production cost modeling.

# 3 Modeling Inputs

## 3.1 Data Translation

For this IRP, Evergy hand selected the alternate resource plans and then dispatched them in a production cost model called MIDAS. In order to develop a comparable database to model in EnCompass, we asked several rounds of discovery questions to get all the data points necessary

[4] Volume 6 Evergy Metro Integrated Resource Plan and Risk Analysis, Figure 2, page 129.

[5] Evergy Metro includes Evergy Metro Missouri and Evergy Metro Kansas.

to set up the EnCompass database. All of the inputs we developed for the EnCompass database were reviewed by Kenneth Sercy with Sercy Consulting to ensure the accuracy and appropriateness of the data translation.

## 3.2 Sources of Modeling Inputs

Our goal was to use the same data and assumptions that Evergy used. However, we did find that there were a few data points and assumptions that we wanted to model differently from Evergy. The assumptions and the reasons for the divergence from Evergy are outlined in the sections that follow. Table 3 shows the different modeling inputs and the sources for those inputs.

**Table 3. Modeling Input Sources**

| **Modeling Inputs** | **Source** |
|---|---|
| New Resource Costs: | |
| Wind, Solar, Solar Hybrid | National Renewable Energy Laboratory ("NREL") Annual Technology Baseline ("ATB") |
| Standalone and Hybrid Battery Storage | Public Service Company of New Mexico RFP Pricing |
| Thermal | Evergy starting capital cost with NREL ATB cost curve |
| Interconnection Cost | Evergy |
| Renewable Shapes: | |
| New Solar | Evergy |
| Existing and New Wind | NREL System Advisor Model ("SAM") |
| Effective Load Carrying Capability ("ELCC") | Evergy |
| Existing Resources[6] | Evergy |
| Existing Contracts | Evergy |
| Load Forecast | Evergy |
| Energy and Capacity Price Forecasts | Evergy |
| Market Purchase and Sales Constraint | EFG |
| Fuel Price Forecast | Evergy |
| $CO_2$ Price Forecast | Evergy |
| Demand Side Management ("DSM) | Evergy (EFG levelized DSM costs) |
| Capital Expenditures | Evergy |
| Transmission Upgrades | Evergy |
| Planning Reserve Margin | Evergy |
| Weighted Average Cost of Capital | Evergy |

## 3.3 New Supply Side Resource Costs

In Volume 4 of the IRP[7], Evergy indicated that it used the 2020 Energy Information Administration ("EIA") Annual Energy Outlook ("AEO"), in addition to assumptions developed by Evergy for new supply side resource costs. In our evaluation of IRPs in other jurisdictions, we have had conversations with other utilities around using the AEO as a source for new resource

[6] Existing resource information includes capacity, fixed and variable operations and maintenance (O&M), dispatch adders, emission rates, maintenance, forced outage rate, ramp rates, minimum up and downtime, and heat rate. Evergy provided this information in discovery responses NEE 1-8, NEE 1-1, NEE 2-33, NEE 3-4, NEE 3-5. Unless otherwise noted, all referenced discovery responses were issued in the Kansas proceeding, KCC Docket No. 19-KCPE-096-CPL.

[7] Volume 4: Supply-Side Resource Analysis, page 31.

costs and utilities have expressed concern[8] that AEO "often has dated new build assumptions for certain resource types, especially renewables and emerging technologies". Indeed, these concerns have been well known for over a decade now and are a prime reason that NREL's Annual Technology Baseline ("ATB") has become more widely used for IRPs.

Evergy did not include solar hybrid and battery standalone resources in the modeling for the Alternate Resource Plans. Our modeling included these resources as supply side options.

Sections 3.3.1 and 3.3.2 outline the costs assumptions we used to model new wind, solar, and storage resources. While we assumed different capital cost and fixed O&M assumptions than Evergy, we did use the same interconnection cost assumptions that Evergy used in its modeling.

### 3.3.1 Wind and Solar

We used NREL's 2020 ATB to develop wind and solar cost inputs for our EnCompass modeling. Figure 1 shows the comparison of our 2023 solar costs compared to Request for Proposal ("RFP") bids received by both the Public Service Company of New Mexico ("PNM") and Xcel Colorado ("Xcel CO"). PNM issued two RFPs, one for replacement resources for its San Juan coal plant, and a second RFP for its share of the Palo Verde nuclear unit. The Xcel Colorado RFP was conducted for the company's last Electric Resource Plan ("ERP") and the information in Figure 1 reflects the winning bids selected by Xcel.[9] The starting levelized cost we modeled for solar is higher than the cost of the RFP bids received by PNM and the approved project bids for Xcel CO.

[8] Feedback provided to the Indiana Utility Regulatory Commission ("IURC") from Vectren and Northern Indiana Public Service Company ("NIPSCO") related to the Statewide Energy Analysis. The comments from Vectren and NIPSCO are documented in the Citizens Action Coalition comments on the IURC Statewide study. CAC-Indiana-Statewide-Analysis-Comments-2-20-2020FINAL.pdf

[9] Slide 8 retrieved from https://www.michigan.gov/documents/mpsc/Feb_18_Competative_Procurement_Presentation__716684_7.pdf

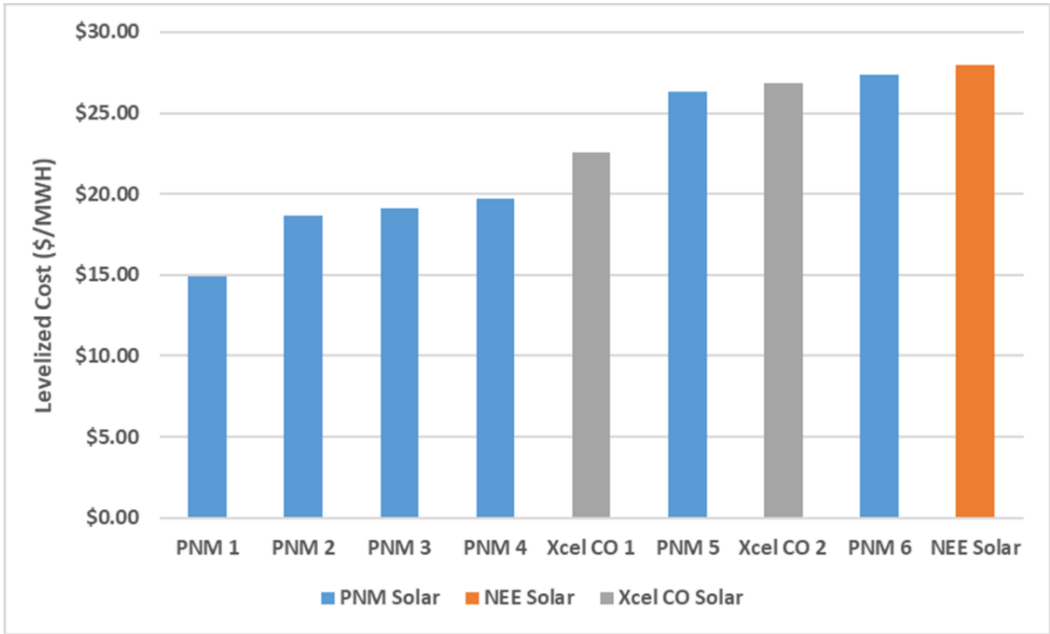


**Figure 1. RFP Bids Compared to NEE Solar Cost**

In addition to the source of capital cost, we also differ from Evergy in the treatment of the Investment Tax Credit ("ITC") for solar and battery storage paired with solar. Our approach monetized the ITC, meaning that it is used to reduce the upfront capital cost of those resources. While Evergy's approach was to "normalize" the ITC, i.e. spread it across the book life of the asset. Because of discounting, normalization decreases the value of the ITC and tends to raise the cost of solar and paired storage significantly, by 20% or more. Utilities can monetize the ITC through financial arrangements that still allow them to own the assets. And the majorities of IRPs we review assume monetization is possible. In general, we believe that resource options should be evaluated in a manner that is neutral on ownership because the point is to minimize consumer cost, not maximize utility return. And indeed, with the ability to monetize the ITC available even to utilities like Evergy, no difference related to ownership should even be necessary.

### 3.3.2 Battery Storage

While we used the ATB to characterize wind and solar pricing, we used project pricing information from project bids received by PNM to characterize battery storage. The reason for that is that the ATB's storage pricing is based on data from 2019 and earlier.[10] The market for utility scale batteries has grown dramatically since 2019[11] with thousands of megawatts of

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[10] See https://atb.nrel.gov/electricity/2021/approach_&_methodology.

[11] As NREL described in its documentation of its storage assumptions, "Battery cost and performance projections in the 2020 ATB are based on a literature review of 19 sources published in 2018 or 2019…" See https://atb.nrel.gov/electricity/2020/index.php?t=st.

batteries expected to come online in the next three years.[12] As those data become more available, we would expect the ATB to absorb it, but in the meantime benchmarking costs against actual project cost data is preferable and more accurate.

We used the average of the PNM bids for the starting cost of the battery storage resources and then applied the NREL ATB mid-case cost curve to develop prices for the entire planning period. One set of cost inputs were developed for the standalone battery storage resources and another for the hybrid storage resources, since they qualify for the ITC.

Utilizing the PNM bids as a source for modeling battery storage costs in our modeling runs is reasonable since the cost reflects actual bids received for battery projects. We have not seen battery prices submitted in response to RFPs that have significant differences across different regions. As such, we would expect these bid prices to be generally applicable to Missouri utilities. Table 4 shows the project pricing information with the two new projects that PNM has received bids for.

**Table 4. PNM Battery Storage Pricing with New Projects[13]**

| | With ITC $/kW-Mo | No ITC $/kW-Mo |
|---|---|---|
| Jicarilla | $9.97 | $13.47 |
| Arroyo | $7.46 | $10.08 |
| Bidder #5 | $7.99 | $10.80 |
| Bidder #2 | $7.70 | $10.41 |
| New Bid | $6.68 | $9.03 |
| New Bid | $7.56 | $10.22 |
| **Avg** | **$7.89** | **$10.67** |

### 3.3.3 Thermal Resources

We used Evergy's starting capital costs for a new Combustion Turbine ("CT") and then applied the cost curve from the NREL's 2020 ATB. After reviewing Evergy's IRPs and observing that there were only a couple of Alternate Resource Plans that evaluated the addition of a Combined Cycle ("CC") unit, we decided to not offer a CC as a replacement resource in our modeling.  This also allowed the model to consider the economic impact of a low-carbon future for the Evergy operating companies.

[12] Energy Information Administration.  "Battery Storage in the United States: An Update on Market Trends".  July 2020.  P. 26 Available at: https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage.pdf
[13] Project bids received for the replacement of San Juan and Palo Verde. Project pricing from NMPRC Case No. 20-00182-UT Direct Testimony of Thomas Fallgren, PNM Table TGF-1, p. 11.

## 3.4 Wind and Solar Shapes

After reviewing the wind and solar shapes modeled by Evergy and learning how shapes are represented in MIDAS (as typical week per month shapes), we decided to develop our own hourly shapes for existing and new wind resources. In response to Data Request No. NEE 2-28 issued in the Kansas proceeding, Evergy said:

> *The MIDAS model renewable profiles provided in response to QNEE-1-8 are in a typical week format. "Renewable Profile 1" has different values for each day of this typical week and is used for most of the Company's wind generation resources. Some other resources use a typical day output curve (repeating the typical day for each day of the week) for their specific location.*[14]

In addition to the shapes being modeled on a typical week basis, Evergy developed several different wind profiles that were shared by the existing wind resources. In our experience, utilities will develop individual hourly shapes for each of the existing wind and solar resources to capture the geographic diversity of those resources. We similarly wanted to be able to capture that geographical diversity because wind currently represents a significant portion of Evergy's system. So we utilized NREL's System Advisor Model ("SAM") to generate hourly profiles for the existing wind generators. We then took an average of those profiles to use as the shape for new wind resources given that we have no specific information about where new wind might be located.

Given Evergy's limited solar resources within its current portfolio, we decided to utilize the same shape that Evergy used to represent production from new solar resources.

## 3.5 Effective Load Carrying Capability ("ELCC")

We used the same ELCC assumptions as Evergy for the existing[15] and new renewables resources modeled. Evergy assumed a 2,000 MW limit of new solar that has a 50% ELCC. We allocated the 2,000 MW across the operating companies based on peak load. Table 5 shows the allocation of the 50% solar ELCC across the three operating companies. This 50% solar ELCC assumption applied to both standalone and solar hybrid resources in our modeling.

[14] Evergy's response to NEE 2-28.

[15] Accreditation from existing renewable resources from Evergy's response to NEE 2-30 and existing thermal resources in NEE 3-5.

**Table 5. Allocation of 50% Solar ELCC (MW) Across Evergy Operating Companies**

| | Metro | Kansas Central | MO West |
|---|---|---|---|
| Amount of 50% Solar ELCC | 1000 | 700 | 300 |

We used Evergy's ELCC assumptions for the existing wind resources for Evergy Metro and Evergy Kansas Central. It is important to note that Evergy assumed a declining ELCC for existing wind between 2022 and 2023. The total accredited capacity of the existing wind resources for Kansas Central in 2022 is 978 MW. Evergy models a decline in the accredited capacity down to 501 MW in 2023.[16]

## 3.6 New Resource Constraints

Since Evergy developed its plans by hand, it did not have to input any constraints on new resources into MIDAS. We developed the new resource constraints in a manner to allow EnCompass to have the option to select up to a certain MW of a particular resource in any given year. In the case of the new solar resources that qualify for the 50% ELCC assumption and for wind projects that can receive the Production Tax Credit ("PTC"), we modeled a total MW constraint. Table 6 outlines the annual and total MW constraints that we modeled for new resources across the entire 20-year planning horizon.

**Table 6. New Resource Constraints Modeled in EnCompass (MW)**

| Resource | Annual Constraint (MW) | Total Constraint (MW) |
|---|---|---|
| Solar at 50% ELCC | - | 700 for Metro; 1000 for KS Central; 300 for MO West |
| Solar and Solar Hybrid at 10% ELCC | 2000 | |
| Wind PTC | - | 400 for Each Company |
| Wind Non-PTC | 1500 | - |
| Battery Storage | 1500 | - |
| Combustion Turbines | 698 | - |

## 3.7 Load, Fuel, and Carbon Forecasts

We used the mid gas price forecast, in addition to the oil and coal price forecast provided to us from Evergy.[17] We also used the load and $CO_2$ price forecasts that Evergy provided to us in discovery.[18]

[16] Evergy discovery response to NEE 5-4 that shows the load and capacity tables for each preferred plan. Please see workbook "QNEE-5-4_2021 IRP Preferred Plans Capacity Summaries". Evergy might be modeling a reduction in the ELCC of existing wind resources to reflect an increase in wind penetration in SPP, but it is not clear why the ELCC changes from 2022 to 2023.
[17] Evergy discovery response to NEE 1-4.
[18] Evergy discovery response to NEE 3-6 and NEE 2-14.

## 3.8 Energy and Capacity Market

The hourly market price forecast that Evergy provided to us contained different assumptions depending on the natural gas and $CO_2$ price assumptions. We used the market price forecast that corresponded to the endpoint with a mid gas price and mid CO2 price from the data that was made available to us.[19] We set up a market interaction within EnCompass to represent Evergy's market exchange with the Southwest Power Pool ("SPP"). We also used Evergy's capacity price assumptions for purchases and sales.[20] Evergy's modeling assumed that each operating company was able to purchase or sell up to 100 MW of capacity in any given year. In a handful of years, our Evergy Metro plan exceeds this limit but it is held for all years in the Kansas Central plan. We felt this was a reasonable assumption to make given the North American Electric Reliability Corporation's ("NERC") assessment for the expected capacity surplus in SPP.[21]

We initially started our EnCompass modeling with the sales and purchase constraints that Evergy used in its MIDAS modeling. However, the initial modeling results in EnCompass returned much higher levels of sales than was reasonable so we applied a stricter sales constraint. EnCompass applies this constraint on an hourly basis. Table 7 shows the sales constraint we modeled for Evergy Metro and Evergy Kansas Central.

**Table 7. Sales Constraint (MW) Applied in EnCompass Modeling**

| | Metro | Kansas Central |
|---|---|---|
| Sales Constraint | 452 | 690 |

## 3.9 Capital Expenditures and Transmission Upgrades

We utilized the information that Evergy provided to us through discovery to model the capital expenditures and transmission upgrades.[22]

Evergy did not provide transmission upgrade costs associated with the retirement of Iatan 2, so our initial modeling did not have any costs. However, we recognize that some costs are likely given the unit's likely contribution to grid strength and to a lesser degree, voltage support, so we added a sensitivity for the cost of converting Iatan 2 to a synchronous condenser. We assumed that the cost would be about $73,311,494..

[19] Evergy discovery response to NEE 2-15.
[20] Evergy discovery response to NEE 2-7.
[21] North American Electric Reliability Corporation ("NERC") 2020 Long-Term Reliability Assessment. Table 1, page 14.
[22] Evergy discovery response to NEE 1-8, NEE 1-8S, and NEE 2-20.

# 4 EnCompass Modeling Results

Our modeling approach was performed in three steps. In the first step, we allowed EnCompass to optimize the coal plant retirement dates for Evergy Metro and Evergy Kansas Central since they have the larger share of the coal plants when compared to Evergy Missouri West and only whole units can be retired. We reviewed the optimized retirement dates from step one and determined a set of retirement dates that aligned between the operating companies to model in step two. Step two took the retirement dates from step one and performed capacity expansion and production cost modeling. Step three involved rerunning Evergy's Preferred Plans in EnCompass so that we could compare the present value of revenue requirements ("PVRR") for the NEE and Evergy Preferred Plans.

## 4.1 Step One Modeling: Optimized Retirement Dates

EnCompass optimizes the retirement date based on the economics of a unit, which include the projected operations and maintenance and the fuel costs for operating the plant. We allowed EnCompass to consider retiring all coal units starting in 2023. Table 8 shows the optimized coal retirement dates for Evergy Metro and Evergy Kansas Central in our EnCompass modeling runs without consideration of the capital expenditures at those units.

**Table 8. Optimized Retirement Dates without Capital Expenditure Consideration**

| Year | Evergy Metro | Evergy Kansas Central |
|---|---|---|
| 2023 | Iatan 1 | LaCygne 1 |
| 2023 | Hawthorn 5 | LaCygne 2 |
| 2026 | LaCygne 1 | - |
| 2026 | LaCygne 2 | - |
| 2026 | - | Jeffrey 1 |
| 2030 | Iatan 2 | Jeffrey 3 |
| 2034 | - | Jeffrey 2 |

The optimized retirement dates indicate a different path for the LaCygne units between Evergy Metro and Evergy Kansas Central. Given the information provided in discovery and in its Kansas IRP[23] related to anticipated environmental retrofit costs of the Jeffrey units, we wanted to evaluate the optimized retirement dates when capital expenditures are incorporated. In order to incorporate the capital expenditures into the retirement decision within EnCompass, we utilized a spreadsheet model from Anchor Power Solutions to translate the capital expenditures into a carrying charge that could be connected to each coal plant. We translated the capital expenditures for each unit and then performed the step one optimization again. Table 9 shows the optimized retirement date results from EnCompass when unit economics include projected capital expenditure streams.

[23] Evergy 2021 Integrated Resource Plan Overview, page 10.

The results from optimizing the retirement dates including capital expenditures show that EnCompass retires the Jeffrey units earlier than when those dates are optimized without capital expenditures. This also impacts the retirement date of LaCygne 1 and 2. We still see a difference in retirement dates for LaCygne 2 between Evergy Metro and Evergy Kansas Central. The Evergy Metro run retires both LaCygne 1 and 2 in 2026 whereas the Kansas Central run retires LaCygne 1 in 2026 and continues to operate LaCygne 2 until its current planned retirement date of 2029.

**Table 9. Optimized Retirement Dates with Capital Expenditures Considered**

| Year | Evergy Metro | Evergy Kansas Central |
|---|---|---|
| 2023 | Iatan 1 | Jeffrey 1 |
| 2024 | Hawthorn 5 | - |
| 2025 | - | Jeffrey 2 |
| 2026 | LaCygne 1 | LaCygne 1 |
| 2026 | LaCygne 2 | Jeffrey 3 |
| 2030 | Iatan 2 | - |

## 4.2 Step Two Modeling: Capacity Expansion and Dispatch

After reviewing the optimized retirement dates from the step one modeling, we selected retirement dates for each of the coal plants that would best reflect the optimized retirement dates and align the dates between the two operating companies for the units that are shared between the operating companies. Table 10 shows the retirement dates that we modeled in step two.

**Table 10. Coal Plant Retirement Dates in NEE Modeling**

| Year | Evergy Metro | Evergy Kansas Central |
|---|---|---|
| 2023 | Iatan 1 | - |
| 2023 | Hawthorn 5 | - |
| 2026 | - | Jeffrey 1-3 |
| 2029 | LaCygne 1 &2 | LaCygne 1 &2 |
| 2032 | Iatan 2 | - |

## 4.3 Step Three Modeling: Rerunning Evergy Preferred Plans

In order to be able to compare our modeling runs with Evergy's Preferred Plan on a cost basis, we reran Evergy's Preferred Plans in EnCompass. These simulations fixed the resources in Evergy's Preferred Plans but updated the inputs to reflect the same wind, solar, and CT costs, existing and new wind profiles, and the levelization of the DSM costs utilized in our resource optimization runs.

Table 11 shows the coal retirement dates that were included in Evergy Metro and Evergy Kansas Central Preferred Plans. The Evergy Metro plan retires LaCygne 1 at its current planned retirement date of 2032 and extends LaCygne 2 for ten years to a retirement date of 2039. Evergy Metro also has Iatan 1 retiring in 2039. For Kansas Central, Jeffrey 3 retires in 2030 and LaCygne 1 retires in 2032. Jeffrey units 1 and 2, LaCygne 2, and Iatan 1 retire in 2039. Table 12 and Table 13 show the expansion plan for Evergy Metro and Evergy Kansas Central. Evergy's Preferred Plan includes modest amounts of new solar and wind and several CT additions after 2040.

We recognize that since the filing of Evergy's IRP in Kansas, Evergy has made changes to the Preferred Plan that include operating Lawrence Unit 5 on natural gas instead of retiring the unit and pursuing 190 MW of new solar in 2023 instead of the 350 MW that was included in the Preferred Plan. Given the extremely late filing of that plan and the lack of modeling to support it, (for example, we do not know if that would also change subsequent resource additions), the modeling of Evergy's Preferred Plan was based on the original IRP filing. We discuss Evergy's new Preferred Plan in more detail in Section 7.6 of this report.

**Table 11. Evergy Metro and Evergy Kansas Central Coal Plant Retirements in Preferred Plan**

| Year | Evergy Metro | Evergy Kansas Central |
|---|---|---|
| 2023 | - | Lawrence 4 & 5 |
| 2030 | - | Jeffrey 3 |
| 2032 | LaCygne 1 | LaCygne 1 |
| 2039 | LaCygne 2 | LaCygne 2 |
| 2039 | Iatan 1 | Jeffrey 1 & 2 |

**Table 12. Evergy Metro Preferred Plan (Capacity in MW)[24]**

| Year | Solar | Wind | CT |
|---|---|---|---|
| 2024 | 230 | | |
| 2025 | | 120 | |
| 2026 | | 120 | |
| 2028 | 120 | | |
| 2029 | 120 | | |
| 2030 | 120 | | |
| 2031 | 120 | | |
| 2032 | 120 | | |
| 2040 | | | 699 |

**Table 13. Evergy Kansas Central Preferred Plan (Capacity in MW)[25]**

| Year | Solar | Wind | CT |
|---|---|---|---|
| 2023 | 350 | | |
| 2024 | | | |
| 2025 | | 300 | |
| 2026 | | 300 | |
| 2028 | 300 | | |
| 2029 | 300 | | |
| 2030 | 300 | | |
| 2031 | 300 | | |
| 2032 | 300 | | |
| 2033 | | | 466 |
| 2038 | | | 233 |
| 2039 | | | |
| 2040 | | | 1631 |

The Preferred Plan presented in Evergy Kansas Central's IRP did not include any new wind additions after 2026. However, the discovery response that Evergy provided to NEE 5-4 included the load and capacity table for Evergy's Preferred Plans. The information Evergy provided in NEE 5-4[26] indicates that the Kansas Central Preferred Plan includes wind additions

[24] Evergy Metro IRP Volume 7: Resource Acquisition Strategy Selection, Table 1, page 3.
[25] Evergy Kansas Central IRP, Table 120, page 165.
[26] The load and capacity table in NEE 5-4 indicates that the new wind UCAP is 60 MW in 2036 and this increases to 150 MW in 2037. In response to NEE 2-30, Evergy stated that new wind was modeled with a 10% ELCC value so any increases in the UCAP value of the new wind must be the result of additional wind coming online in 2037.

of 90 MW UCAP or 900 MW ICAP in 2037. Although these resources were not shown in Table 120 of the IRP, they were included in the load and capacity table provided in NEE 5-4, so we included this amount of wind in our modeling of the Evergy Kansas Central Preferred Plan.

## 4.4 NEE Preferred Capacity Expansion Plans

NEE's capacity expansion optimization runs produced a plan that results in earlier coal retirements, higher levels of wind, solar, and storage additions, and less CT capacity when compared to Evergy's Preferred Plans. Figure 2 shows the annual capacity expansion plan for the NEE Evergy Metro Preferred Plan between 2021 and 2040 and Figure 3 shows the capacity expansion plan for the NEE Evergy Kansas Central Preferred Plan.

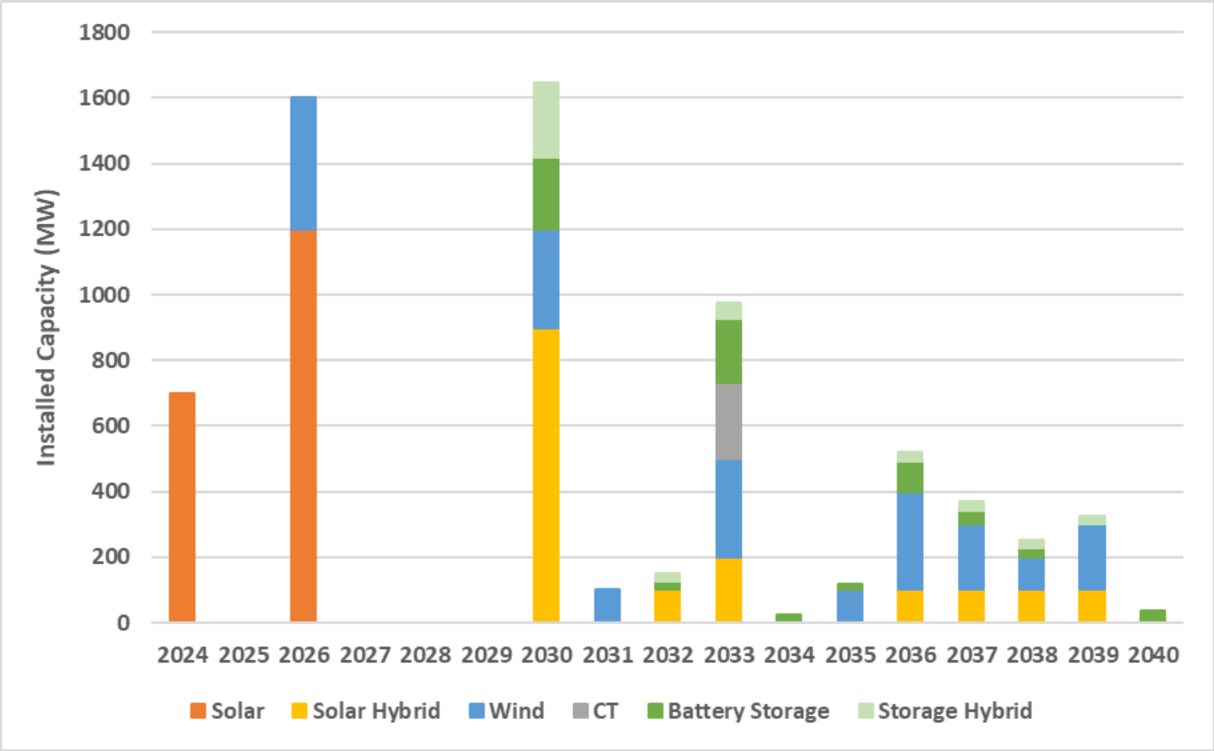


**Figure 2. Capacity Expansion Plan for the NEE Metro Preferred Plan (Installed Capacity MW)**

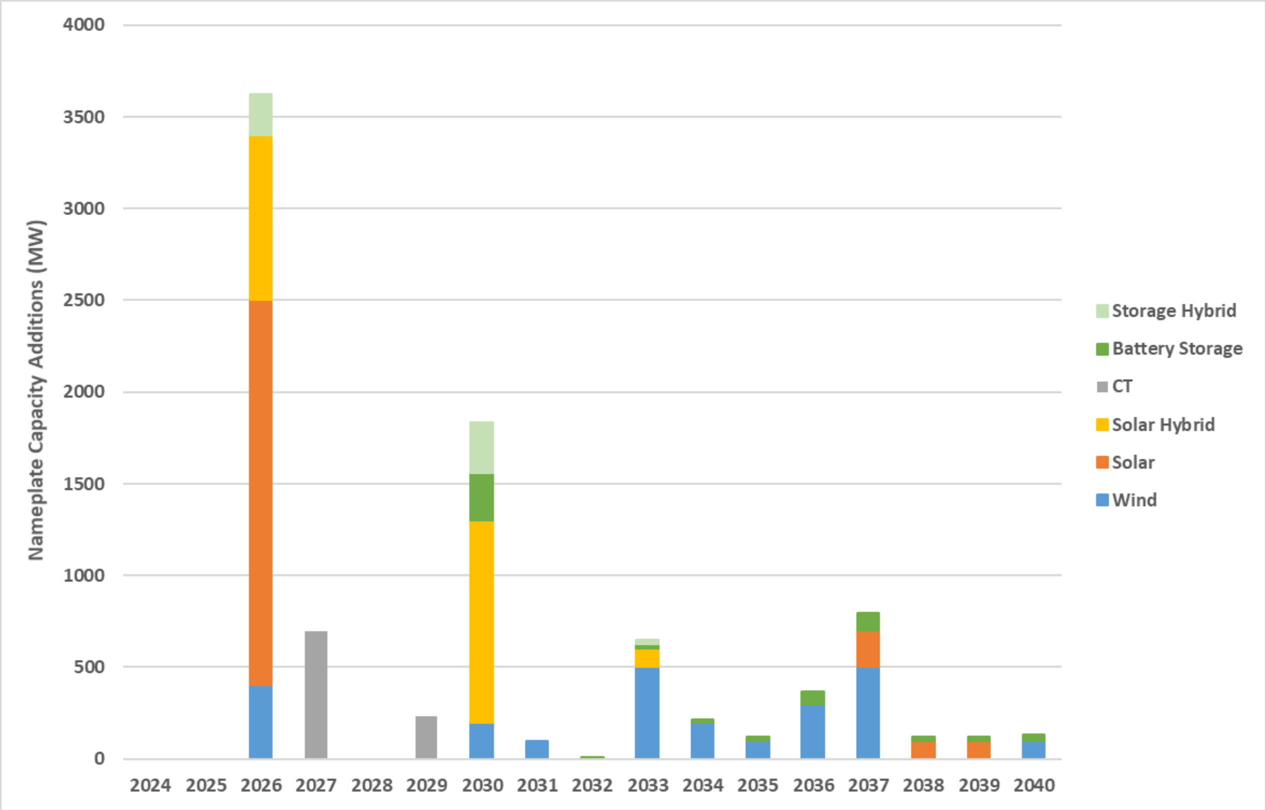


**Figure 3. Capacity Expansion Plan for the NEE KS Central Preferred Plan (Installed Capacity MW)**

Table 14 shows the total installed capacity additions (MW) between 2021 and 2040 for Evergy Metro and Evergy Kansas Central in the NEE Preferred Plans. For both Evergy Metro and Evergy Kansas Central, the expansion plan includes significant levels of solar, solar hybrid, wind, standalone battery storage, and hybrid battery storage resources. There is one CT added in the NEE Evergy Metro Preferred Plan and four CTs added in the Evergy Kansas Central Preferred Plan.

**Table 14. Total Installed Capacity Additions (MW) for Evergy Metro and Evergy Kansas Central (2021 – 2040)**

| Resources | Metro (MW) | Kansas Central (MW) |
|---|---|---|
| Solar | 1900 | 2500 |
| Solar Hybrid | 1600 | 2100 |
| Wind | 2000 | 2400 |
| Storage | 684 | 570 |
| Storage Hybrid | 400 | 525 |
| CTs | 233 | 932 |

**Error! Not a valid bookmark self-reference.** and Table 16 show the load and capacity tables for the NEE Preferred Plans for Evergy Metro and Evergy Kansas Central.

### Table 15. Load and Capacity Table for NEE Metro Preferred Plan (Firm Capacity MW)

| | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Peak Demand (Net DSM)** | 3476 | 3467 | 3369 | 3322 | 3280 | 3247 | 3220 | 3200 | 3179 | 3165 | 3165 | 3179 | 3189 | 3202 | 3219 | 3237 | 3250 | 3264 | 3280 | 3297 |
| **Existing Resources** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Nuclear:Nuclear | 553 | 553 | 553 | 553 | 553 | 553 | 553 | 553 | 553 | 553 | 553 | 553 | 553 | 553 | 553 | 553 | 553 | 553 | 553 | 553 |
| Gas/Oil:Combined Cycle | 225 | 225 | 225 | 225 | 225 | 225 | 225 | 225 | 225 | 225 | 225 | 225 | 225 | 225 | 225 | 225 | 225 | 225 | 225 | 225 |
| Gas/Oil:Combustion Turbine | 933 | 933 | 933 | 933 | 933 | 933 | 933 | 933 | 933 | 933 | 933 | 933 | 933 | 933 | 933 | 933 | 933 | 933 | 933 | 933 |
| Coal:Conventional | 2249 | 2249 | 2249 | 1195 | 1195 | 1195 | 1195 | 1195 | 1195 | 491 | 491 | 491 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydro:Hydroelectric | 60 | 60 | 60 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Renewable:Solar PV | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Renewable:Wind | 293 | 293 | 293 | 293 | 293 | 293 | 293 | 293 | 293 | 293 | 293 | 293 | 243 | 243 | 243 | 194 | 123 | 89 | 40 | 40 |
| Storage:Battery | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Contract:Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Contract:Sale | -378 | -380 | -383 | -30 | -30 | -15 | -15 | -15 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Firm Capacity Existing** | **3934** | **3932** | **3929** | **3168** | **3168** | **3183** | **3183** | **3183** | **3198** | **2494** | **2494** | **2494** | **1953** | **1953** | **1953** | **1904** | **1833** | **1799** | **1750** | **1750** |
| **Net Resource (Need)/Surplus** | 568 | 575 | 671 | -44 | -2 | 46 | 73 | 93 | 129 | -561 | -561 | -614 | -1135 | -1149 | -1165 | -1355 | -1394 | -1469 | -1535 | -1562 |
| New Projects | | | | | | | | | | | | | | | | | | | | |
| New Wind | 0 | 0 | 0 | 0 | 0 | 40 | 40 | 40 | 40 | 70 | 80 | 80 | 110 | 110 | 120 | 150 | 170 | 180 | 200 | 200 |
| New Solar | 0 | 0 | 0 | 350 | 350 | 470 | 470 | 470 | 470 | 470 | 470 | 470 | 470 | 470 | 470 | 470 | 470 | 470 | 470 | 470 |
| New Solar Hybrid | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 90 | 90 | 100 | 120 | 120 | 120 | 130 | 140 | 150 | 160 | 160 |
| New Battery Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 198 | 198 | 221 | 394 | 416 | 432 | 517 | 556 | 582 | 582 | 615 |
| New Hybrid Battery Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 203 | 203 | 225 | 270 | 270 | 270 | 293 | 315 | 338 | 360 | 360 |
| New CT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 233 | 233 | 233 | 233 | 233 | 233 | 233 | 233 |
| Capacity Purchase | 0 | 0 | 0 | 203 | 156 | 0 | 0 | 0 | 0 | 20 | 10 | 0 | 22 | 14 | 7 | 0 | 0 | 0 | 0 | 0 |
| Firm Capacity New Resources | 0 | 0 | 0 | 553 | 506 | 510 | 510 | 510 | 510 | 1051 | 1051 | 1096 | 1618 | 1633 | 1652 | 1792 | 1884 | 1952 | 2005 | 2038 |
| **Total Firm Capacity** | **3934** | **3932** | **3929** | **3721** | **3674** | **3693** | **3693** | **3693** | **3708** | **3545** | **3545** | **3590** | **3572** | **3587** | **3605** | **3696** | **3717** | **3751** | **3755** | **3788** |
| **Reserve Margin** | **13.18%** | **13.43%** | **16.64%** | **12.00%** | **12.00%** | **13.73%** | **14.71%** | **15.42%** | **16.63%** | **12.00%** | **12.00%** | **12.92%** | **12.00%** | **12.00%** | **12.00%** | **14.18%** | **14.38%** | **14.93%** | **14.48%** | **14.90%** |

## Table 16. Load and Capacity Table for NEE Kansas Central Preferred Plan (Firm Capacity MW)

| | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Peak Demand (Net DSM)** | 4,995 | 5,026 | 4,937 | 4,877 | 4,822 | 4,782 | 4,750 | 4,730 | 4,714 | 4,702 | 4,699 | 4,706 | 4,714 | 4,734 | 4,761 | 4,793 | 4,814 | 4,840 | 4,868 | 4,895 |
| **Existing Resources** | | | | | | | | | | | | | | | | | | | | |
| Nuclear:Nuclear | 553 | 553 | 553 | 553 | 553 | 553 | 553 | 553 | 553 | 553 | 553 | 553 | 553 | 553 | 553 | 553 | 553 | 553 | 553 | 553 |
| Gas/Oil:Combined Cycle | 196 | 196 | 196 | 196 | 196 | 196 | 196 | 196 | 196 | 196 | 196 | 196 | 196 | 196 | 196 | 196 | 196 | 196 | 196 | 196 |
| Gas/Oil:Combustion Turbine | 1427 | 1427 | 1427 | 1427 | 1427 | 1427 | 1427 | 1427 | 1427 | 1427 | 1427 | 1427 | 1427 | 1427 | 1427 | 1427 | 1427 | 1427 | 1427 | 1427 |
| Coal:Conventional | 3020 | 3020 | 3020 | 2534 | 2534 | 2534 | 704 | 704 | 704 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Renewable:Solar PV | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| Renewable:Wind | 501 | 501 | 501 | 501 | 501 | 501 | 501 | 501 | 475 | 475 | 475 | 475 | 380 | 368 | 368 | 313 | 179 | 179 | 179 | 172 |
| Storage:Battery | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Contract:Purchase | 502 | 486 | 486 | 486 | 486 | 486 | 486 | 486 | 468 | 468 | 468 | 468 | 468 | 468 | 468 | 468 | 468 | 468 | 468 | 468 |
| Contract:Sale | -329 | -329 | -250 | -250 | -250 | -250 | -250 | -250 | -250 | -250 | -250 | -250 | -250 | -250 | -250 | -250 | -250 | -250 | -250 | -250 |
| **Firm Capacity Existing** | **5,871** | **5,855** | **5,934** | **5,448** | **5,448** | **5,448** | **3,618** | **3,618** | **3,574** | **2,870** | **2,870** | **2,870** | **2,775** | **2,762** | **2,762** | **2,708** | **2,574** | **2,574** | **2,574** | **2,566** |
| **Net Resource (Need)/Surplus** | **876** | **829** | **997** | **571** | **626** | **666** | **-1,132** | **-1,112** | **-1,140** | **-1,832** | **-1,829** | **-1,836** | **-1,939** | **-1,972** | **-1,998** | **-2,084** | **-2,240** | **-2,266** | **-2,294** | **-2,329** |
| **New Projects** | | | | | | | | | | | | | | | | | | | | |
| New Wind | 0 | 0 | 0 | 0 | 0 | 40 | 40 | 40 | 40 | 60 | 70 | 70 | 120 | 140 | 150 | 180 | 230 | 230 | 230 | 240 |
| New Solar | 0 | 0 | 0 | 0 | 0 | 490 | 490 | 490 | 490 | 490 | 490 | 490 | 490 | 490 | 490 | 490 | 510 | 520 | 530 | 530 |
| New Solar Hybrid | 0 | 0 | 0 | 0 | 0 | 210 | 210 | 210 | 210 | 320 | 320 | 320 | 330 | 330 | 330 | 330 | 330 | 330 | 330 | 330 |
| New Battery Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 232 | 232 | 240 | 262 | 277 | 297 | 356 | 445 | 464 | 485 | 513 |
| New Hybrid Battery Storage | 0 | 0 | 0 | 0 | 0 | 203 | 203 | 203 | 203 | 450 | 450 | 450 | 473 | 473 | 473 | 473 | 473 | 473 | 473 | 473 |
| New CT | 0 | 0 | 0 | 0 | 0 | 0 | 698 | 698 | 930 | 930 | 930 | 930 | 930 | 930 | 930 | 930 | 930 | 930 | 930 | 930 |
| Capacity Purchase | 0 | 0 | 0 | 14 | 0 | 0 | 61 | 39 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Capacity New Resources | 0 | 0 | 0 | 14 | 0 | 943 | 1702 | 1679 | 1873 | 2482 | 2492 | 2500 | 2605 | 2640 | 2670 | 2759 | 2917 | 2947 | 2978 | 3016 |
| **Total Firm Capacity** | **5,871** | **5,855** | **5,934** | **5,462** | **5,448** | **6,391** | **5,320** | **5,298** | **5,447** | **5,353** | **5,363** | **5,371** | **5,380** | **5,402** | **5,432** | **5,468** | **5,492** | **5,521** | **5,552** | **5,582** |
| **Reserve Margin** | **17.54%** | **16.50%** | **20.19%** | **11.99%** | **12.98%** | **33.64%** | **11.99%** | **11.99%** | **15.55%** | **13.82%** | **14.12%** | **14.12%** | **14.12%** | **14.11%** | **14.10%** | **14.09%** | **14.08%** | **14.07%** | **14.06%** | **14.04%** |

## 4.5 Present Value of Revenue Requirements ("PVRR")

EnCompass has the ability to calculate and report PVRRs and so we used those reported PVRRs to compare the costs of Evergy's Preferred Plans to the NEE Preferred Plans for Evergy Metro and Evergy Kansas Central. Table 17 shows the PVRRs from our re-simulation of Evergy's Preferred Plans against the NEE Preferred Plans. The NEE Metro Preferred Plan, which contains more coal plant retirements and higher levels of renewables and storage, has significant cost savings when compared to the Evergy Metro Preferred Plan. The NEE Kansas Central Preferred Plan, which also has more coal plant retirements and higher levels of renewable and storage resources, does not have the same magnitude of cost savings when compared to the Evergy Kansas Central Preferred Plan, but the PVRR results show modest cost savings for the NEE Kansas Central Preferred Plan when evaluating the 20 year PVRR.

Table 17a also reports the 10 and 15 year PVRRs for NEE and our rerun of Evergy's Preferred Plans in accordance with the Kansas IRP Framework for reporting PVRRs. It is important to note that the modeling we conducted optimized the capacity expansion plan out to 2040 and we are reporting the results of the PVRR for the production cost runs according to the 10, 15, and 20 year timeframes as requested in the Kansas IRP Framework.

**Table 17a. PVRR Comparison ($000) Between NEE and Evergy Preferred Plans**

| Operating Company | NEE PVRR ($000) | Evergy PVRR ($000) | % Difference |
|---|---|---|---|
| **20 Year PVRR** | | | |
| Metro | $11,970,450 | $12,602,399 | -5.01% |
| Kansas Central | $20,419,092 | $20,608,938 | -0.92% |
| **15 Year PVRR** | | | |
| Metro | $9,999,092 | $10,158,039 | -1.56% |
| Kansas Central | $16,922,031 | $16,701,602 | 1.32% |
| **10 Year PVRR** | | | |
| Metro | $7,417,785 | $7,358,430 | 0.81% |
| Kansas Central | $12,400,583 | $12,114,436 | 2.36% |

While PVRRs are certainly useful information they don't convey any information about the elements of the plan that result in the PVRR. We observed that spot market sales of energy have a large influence on the PVRRs and therefore we also wanted to present the same PVRR comparison but without sales revenue.  Certainly Evergy will continue to buy and sell power within SPP, but the volume of sales and magnitude of revenue to the Company is an area of particular uncertainty because it depends a great deal on the changes in generation mix and load of all the utilities in SPP and not just on the characteristics of Evergy's generators and load. Relying on a plan with significant sales revenue has both more upside and downside risk in the sense that if those sales don't materialize as modeled total cost to customers will actually rise. Table 18b shows the 10, 15, and 20 year PVRR comparison for the NEE Preferred Plans and our simulation of the Evergy Preferred Plans excluding sales revenue for both plans. Because Evergy's Preferred Plans include many more sales than NEE's plans, excluding those sales magnifies the difference in cost between Evergy's Preferred Plans and NEE's Preferred Plans.

**Table 18b. PVRR Comparison ($000) Between NEE and Evergy Preferred Plans Net of Sales Revenue**

| Operating Company | NEE PVRR ($000) | Evergy PVRR ($000) | % Difference |
|---|---|---|---|
| **20 Year PVRR** | | | |
| Metro | $13,904,477 | $15,180,360 | -8.40% |
| Kansas Central | $21,771,859 | $22,832,125 | -4.64% |
| **15 Year PVRR** | | | |
| Metro | $11,435,608 | $12,485,140 | -8.41% |
| Kansas Central | $17,914,268 | $18,632,656 | -3.86% |
| **10 Year PVRR** | | | |
| Metro | $8,321,387 | $9,032,581 | -7.87% |
| Kansas Central | $13,017,421 | $13,571,181 | -4.08% |

## 4.6 Carbon Emission Reductions

Our modeling results in a significantly faster pace of coal plant retirements when compared to Evergy's Preferred Plans. Figure 4 shows the annual $CO_2$ emissions for Evergy's Preferred Plans and NEE Preferred Plans.

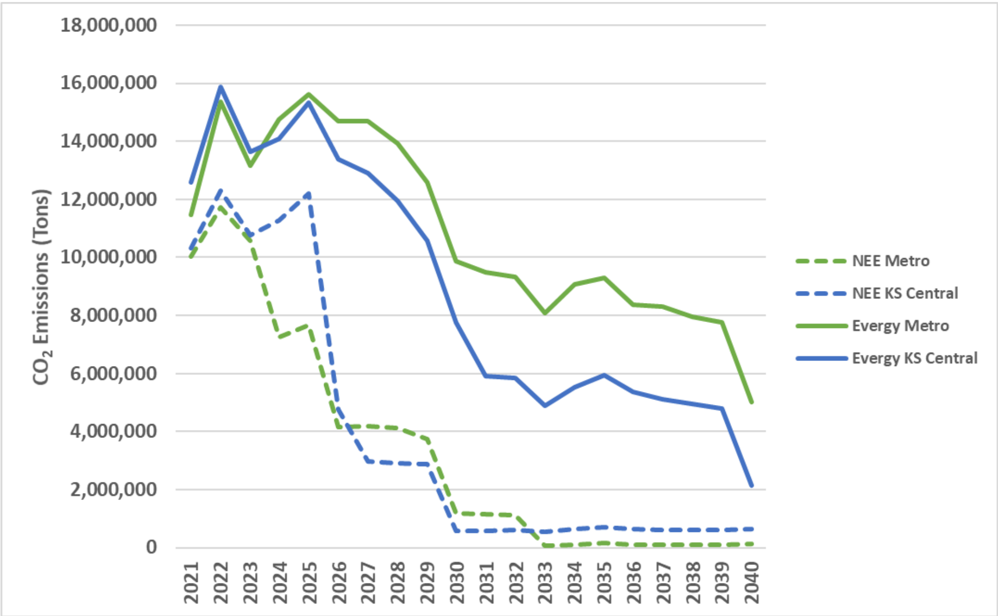


**Figure 4. Carbon Emissions of NEE and Evergy Preferred Plans**

When compared to the 2021 emissions, the NEE Metro Preferred Plan (dashed green line) achieves an 88% reduction in $CO_2$ emissions by 2030 and a 99% reduction by 2040. The NEE Kansas Central Preferred Plan (dashed blue line) achieves a 95% reduction in $CO_2$ emissions by 2030 and remains at that 95% reduction level through the end of the planning period. On the other hand, the Evergy Metro Preferred Plan (green line) achieves a much more modest 14% reduction from 2021 $CO_2$ emission levels by 2030, and only a 56% reduction by 2040. The Evergy Kansas Central Preferred Plan (blue line) achieves a somewhat larger, though still modest, 38% reduction in $CO_2$ emissions by 2030 and an 83% reduction by 2040.

## 4.7 Additional Energy Efficiency Scenario

The 2019 Market Potential Study ("MPS") completed for Evergy included energy efficiency savings consistent with the Missouri Energy Efficiency Investment Act ("MEEIA"). Despite the inclusion of this level of savings in the MPS, we could not find any evidence in Evergy's IRP filing or discovery responses that this level of energy efficiency was modeled by Evergy. The MPS says that the MEEIA level of savings represents incremental savings of just over 1% of sales.[27] The NEE modeling runs included the Realistic Potential Achievable ("RAP") level of energy efficiency savings for each operating company. Table 19 shows the comparison of energy efficiency savings in the RAP and MEEIA scenarios.

[27] Evergy 2019 DSM Potential Study. Page 2.

**Table 19. MPS Energy Efficiency Summary of Savings (Annual GWH)[28]**

| | 2023 | 2024 | 2025 | 2032 | 2042 |
|---|---|---|---|---|---|
| RAP | 108 | 220 | 313 | 709 | 790 |
| MEEIA | 199 | 414 | 580 | 1,273 | 1,637 |

We created modeling inputs for the MEEIA scenario based on the discovery responses we received from Evergy.[29] Evergy used its Missouri MPS results to model energy efficiency in the Kansas service territories. Evergy applied the MO MPS results to its Kansas customers based on a peak load proportional calculation. We used the same process to develop the energy efficiency savings and costs to apply the MEEIA MPS results to Evergy's Kansas customers. We discuss our recommendations related to the modeling of energy efficiency in Section 7.4.

Table 20 shows the PVRR comparison of the NEE modeling runs with the RAP level of energy efficiency against the NEE modeling runs with the MEEIA level of energy efficiency savings. The results indicate that there are modest cost savings with the MEEIA level of energy efficiency for the 10, 15, and 20 year PVRR comparison.

**Table 20. PVRR Comparison of NEE Plans with the RAP and MEEIA Levels of Energy Efficiency**

| Operating Company | RAP | MEEIA | % Difference |
|---|---|---|---|
| **20 Year PVRR** | | | |
| NEE Metro | $11,970,450 | $11,932,463 | -0.32% |
| NEE Kanas Central | $20,419,092 | $20,295,099 | -0.61% |
| **15 Year PVRR** | | | |
| NEE Metro | $9,999,092 | $9,971,406 | -0.28% |
| NEE Kansas Central | $16,922,031 | $16,829,657 | -0.55% |
| **10 Year PVRR** | | | |
| NEE Metro | $7,417,785 | $7,406,202 | -0.16% |
| NEE Kansas Central | $12,400,583 | $12,361,774 | -0.31% |

The NEE Preferred Plan with the MEEIA level of energy efficiency savings also has a 20 year PVRR that is about 1.52% less than that of Evergy's Preferred Plan for Kansas Central.

[28] Evergy 2019 DSM Potential Study. Table 1-1, page 2.

[29] It is our understanding that Evergy did not model the MEEIA level of energy efficiency for this IRP. We used the annual savings information for the MEEIA scenario that was provided through discovery and applied the monthly shape from the Realistic Achievable Potential to shape the MEEIA savings from an annual to a monthly basis.

## 4.8 Renewable Energy Cost Sensitivity

We wanted to test the impact that higher wind and solar costs would have on the PVRR difference between the NEE and Evergy Preferred Plans to see if there would still be a significant difference in PVRR. We increased the cost of the new wind and solar resources in both the NEE and the Evergy Preferred Plans by 25% and Table 21a gives the resulting PVRRs and the new difference between plans.

**Table 21a. PVRR Comparison for Renewable Price Sensitivity**

| Operating Company | NEE PVRR ($000) | Evergy PVRR ($000) | % Difference |
|---|---|---|---|
| **20 Year PVRR** | | | |
| Metro | $12,415,049 | $12,715,201 | -2.36% |
| Kansas Central | $20,957,329 | $20,914,806 | 0.20% |
| **15 Year PVRR** | | | |
| Metro | $10,293,165 | $10,242,634 | 0.49% |
| Kansas Central | $17,271,212 | $16,894,571 | 2.18% |
| **10 Year PVRR** | | | |
| Metro | $7,564,606 | $7,403,556 | 2.13% |
| Kansas Central | $12,567,705 | $12,216,305 | 2.80% |

Performing this cost sensitivity confirms that there would still be significant cost savings under the NEE Metro Preferred Plan even if the new wind and solar resources were 25% higher. The NEE Kansas Central Preferred Plan does show a slight increase in the 20 year PVRR over the Evergy Kansas Central Preferred Plan under this sensitivity. Table 21a also shows the 10 and 15 year PVRRs in accordance with the Kansas IRP Framework. Our modeling was performed on a 20 year basis as the capacity expansion plan was optimized out to 2040. The PVRRs reported for the 10 and 15 year periods reflect the PVRRs from the production cost runs that were performed on the plans optimized out to 2040.

Table 20b shows the comparison of the NEE and Evergy Preferred Plans under the renewable cost sensitivity when the sales revenue is removed from the PVRR, which continue to have an outsized influence on the Evergy plans.

**Table 22b. PVRR Comparison for Renewable Price Sensitivity Net of Sales Revenue**

| Operating Company | NEE PVRR ($000) | Evergy PVRR ($000) | % Difference |
|---|---|---|---|
| **20 Year PVRR** | | | |
| Metro | $14,349,076 | $15,293,163 | -6.58% |
| Kansas Central | $22,310,097 | $23,137,993 | -3.71% |
| **15 Year PVRR** | | | |
| Metro | $11,729,682 | $12,569,735 | -7.16% |
| Kansas Central | $18,263,450 | $18,825,626 | -3.08% |
| **10 Year PVRR** | | | |
| Metro | $8,468,208 | $9,077,707 | -7.20% |
| Kansas Central | $13,184,544 | $13,673,050 | -3.71% |

## 4.9 Iatan 2 Transmission Upgrade Proxy Costs

We included the transmission upgrade costs for coal plant retirements that were provided to us by Evergy in our modeling for the NEE and Evergy Preferred Plans. Since Evergy did not provide us with any transmission upgrade costs for the retirement of Iatan 2, we decided to evaluate the additional cost of converting Iatan 2 to a synchronous condenser when it retires in the NEE Preferred Plans. We assumed a cost of $73,311,494 and included this additional cost as a post-processing adjustment to the NEE plan.

**Table 23. PVRR Comparison with Iatan 2 Proxy Transmission Upgrade Cost (20 year PVRR)**

| Operating Company | NEE PVRR ($000) | Evergy PVRR ($000) | % Difference |
|---|---|---|---|
| Metro | $11,991,234 | $12,602,399 | -4.85% |

## 4.10 Securitization

New Kansas legislation that was passed in 2021, House Bill 2072, enables the use of securitization for cost recovery of remaining plant balances when coal units are retired on an accelerated schedule. We quantified the impact that securitization would have on the PVRR cost outcomes using a spreadsheet tool developed by the Rocky Mountain Institute. Figure 5 displays the net present value of the coal unit balances that would be recovered from customers under two cases: a regulatory asset case and a securitization case. In the regulatory asset case, when a coal unit is retired before it is fully depreciated, the remaining plant balance is assumed to be recovered as a regulatory asset at Evergy's weighted average cost of capital; the regulatory asset is assumed to be recovered over a 10-year period unless the unit's remaining book life is less than 10 years. In the securitization case, coal units retired on an accelerated schedule have their remaining plant balances securitized and recovered at a significantly lower cost of capital.

Our results show that compared to the regulatory asset case, securitizing the plant balances would reduce customer costs. Further, the cost savings are considerably higher in the NEE Preferred Plans. Across Evergy Metro and Evergy Kansas Central together, securitization saves approximately $130 million with the Evergy Preferred Plan, and approximately $730 million with the NEE Plan.

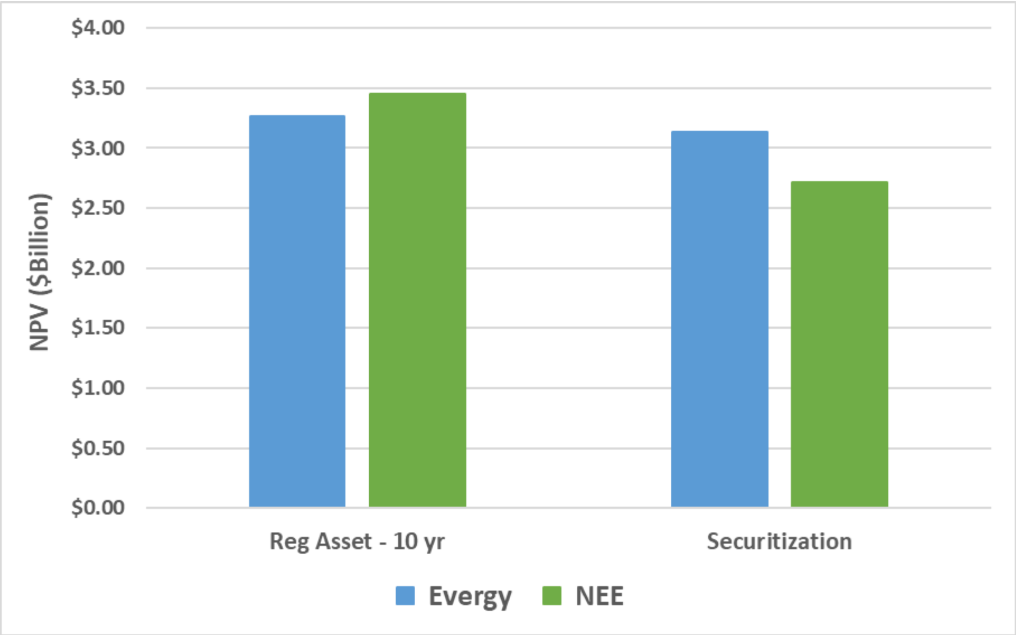


**Figure 5. NPV ($Billion) of Regulatory Asset and Securitization for Evergy and NEE Preferred Plans**

Figures 6 and 7 illustrate the benefits of securitization relative to the full PVRRs of the plans, and broken out into Evergy Metro and Evergy Kansas Central. The cost of the NEE Preferred Plan, including both going-forward costs and coal plant balance recovery, is reduced by about 2.75% for Evergy Metro and about 1.60% for Evergy Kansas Central when securitization is used instead of the regulatory asset approach, whereas the analogous cost of the Evergy Preferred Plan is reduced by about 0.05% for Evergy Metro and about .56% for Evergy Kansas Central.

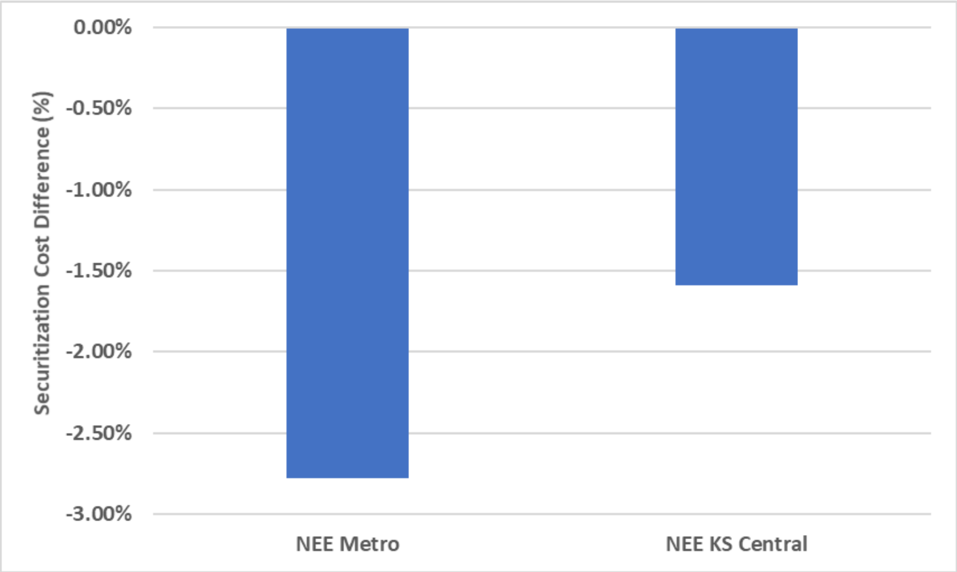


**Figure 6. NEE Securitization and Regulatory Asset Cost Difference (%)**

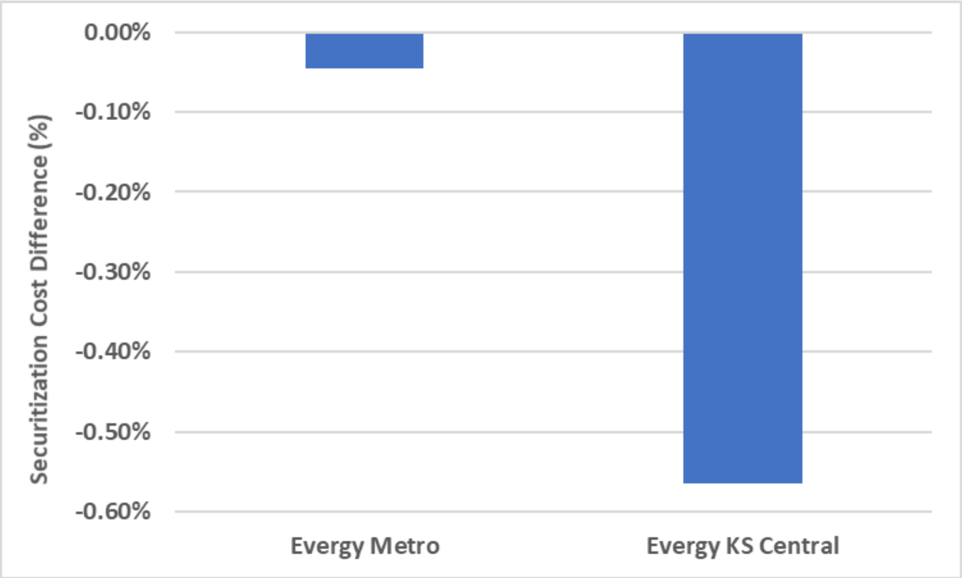


**Figure 7. Evergy Securitization and Regulatory Asset Cost Difference (%)**

# 5 Extreme Weather and Reliability

As with the Commission, Evergy, and other stakeholders, we are also keenly concerned about reliability. So we wanted to explore how the NEE Plans would fair under extreme weather conditions. In Evergy's IRP, that analysis was contained in a scenario that increased peak load. While Evergy's IRP describes that scenario as related to summer peaks only, the data we received increased the peak in all months of the year, so we applied it as such to a sensitivity on the NEE Evergy Metro Preferred Plan.

## 5.1 Evergy's Extreme Temperature Scenario

In its IRP, Evergy developed an extreme temperature load forecast that increased the monthly peak forecast for each year of the planning period.

We applied this extreme temperature forecast[30] to the NEE Evergy Metro Preferred Plan in the year 2030 to evaluate how our plan perform after large portions of the renewable additions and most of the coal unit retirements had occurred. In only two hours of the year, both of which were in July, did the demand for energy exceed the units available on Evergy's system. Given the events of February 2021, however, we chose to focus in on the operation of Evergy's system during the winter months. We selected one of the worst case days, January 14, 2030. The following day, the 15th, is the peak day, but system operations relied less on imports and actually exported energy during some hours, so we are showing the 14th in Figure 8 instead.

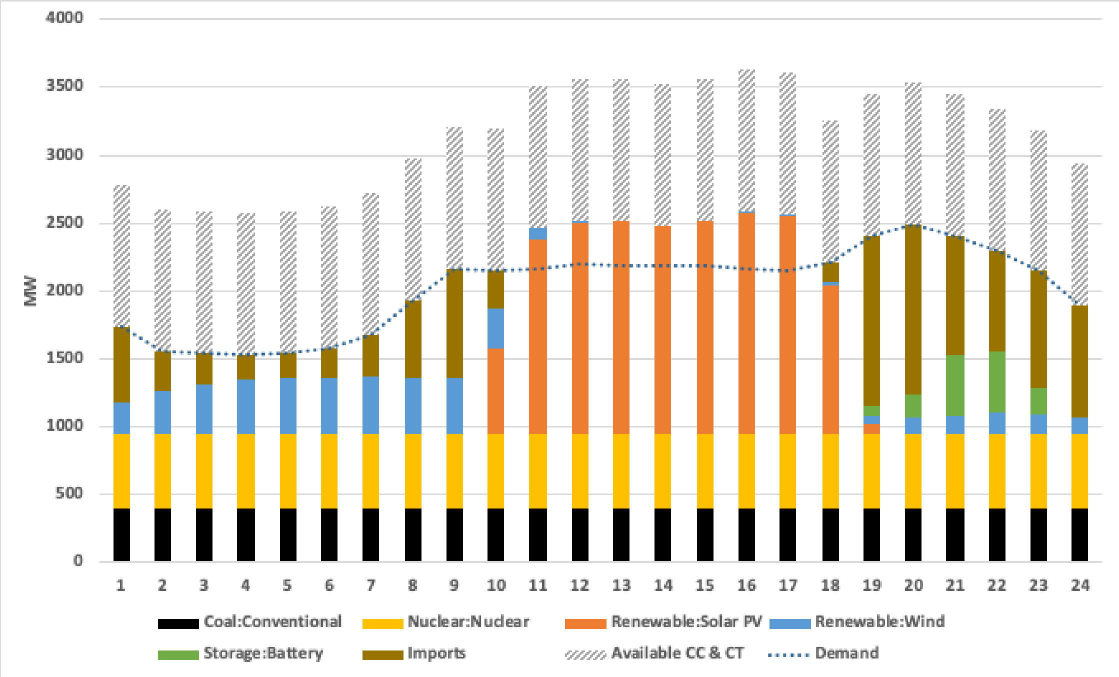


**Figure 8. NEE Evergy Metro Preferred Plan Dispatch Under Extreme Weather Scenario**

The total number of generators in the portfolio more than exceeds demand (dotted blue line) by a wide margin. But EnCompass found imports (brown bars) more economical than operating Evergy's CC and CT units (the patterned gray bars) so it relies on those to fill in the morning and evening hours. Storage (green bars) contributes only modestly because there is not much of it in the plan even by 2030.

[30] Response to NEE 4-4, file named "QNEE-4-4_Metro_Load Peak DSM-c"

Despite the fact that the NEE Preferred Plans meet the same resource adequacy requirements as Evergy's plan, we intend to explore some additional resources for their potential to reduce imported energy. Those resources include flow batteries (batteries with an 8 – 12 hour duration) and multi-day storage. Finally, it is important to note that the performance of energy efficiency ("EE") does not change under this scenario. Just as load increases under unusually hot or cold weather conditions, the impacts of EE should change (improve) too. And neither we nor Evergy have temperature adjusted demand curves to apply to this analysis.

## 5.2 Current Limitations of Resource Adequacy Analyses

As the Commission navigates the likelihood of changing approaches to resource adequacy in SPP, we wanted to offer some thoughts on the limitations of resource adequacy analyses that may help frame the discussions to come. It's also important to note that approaches to resource adequacy in general are very much in flux at the moment around the country. Neither Evergy's analysis nor our application of that approach to the NEE Preferred Plan constitutes a complete resource adequacy assessment. The February Arctic Event has caused a national reckoning of how we evaluate whether a system is resource adequate or not. Such evaluations are complicated by problems with resource adequacy analyses themselves which often suffer from limitations such as:

1. Lack of sufficient synchronous renewable production and demand profiles;
2. Lack of meteorological consistency in artificial renewable and demand datasets;
3. Lack of temperature dependent thermal deratings;
4. Lack of weather dependent DSM profiles;
5. Not capturing fuel supply interruptions ; and
6. No reflection of forward looking climate change impacts.

There are very few sources of historical renewable production data - one of the most widely used is NREL's System Advisor Model ("SAM"). SAM data has the advantage of being publicly available and with wide geographic coverage. Its wind data set covers the years 2007 - 2013 and solar data covers years 1998 – 2020, so only seven years overlap. This is important because wind, solar, and demand datapoints utilized in a resource adequacy analysis need to arise from the same meterological conditions. Unless atmospheric conditions are also being simulated then the data used to determine resource adequacy need to be time synchronous so that the consistency of meteorological conditions can be assured. Without only seven years of overlap, some resource adequacy modelers will create artificial renewable and load datasets that assume datapoints from different years can be picked and chosen so long as the underlying temperature and/or month is the same.

Such an approach is highly problematic and Figure 9, helps illustrate why.

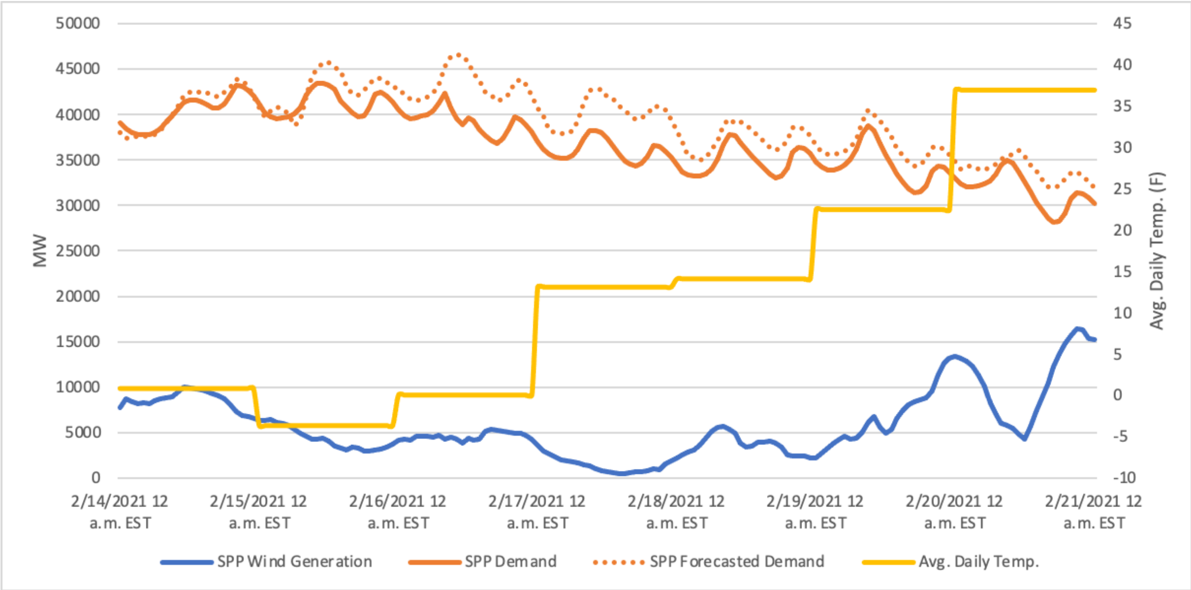


**Figure 9. Comparison of Wind Generation, Load, and Average Temperature in SPP During February 2021 Winter Storm**

Figure 9 shows the pattern of load, wind generation, and average daily temperature in SPP during the February winter storm event. Demand is represented by the two orange curves because forecasted demand could not be met by available generation. Daily temperature is in yellow and one can see an obvious inverse correlation between temperature and demand. As temperature drops, demand increases, and as temperature increases demand drops. However, wind production doesn't hold the same relationship. It drops as the cold weather sets in, but even as temperature rises it is several days before wind generation picks up again. If these data were sampled based on temperature alone it could miss the important dynamics of this event.

Many resource adequacy analyses also assume that the probability of forced outage at thermal units is the same regardless of the time of year or weather conditions. However, several studies have shown correlation between extreme heat or cold and increased thermal derates/decreased availability.[31] Particularly because load tends to increase significantly under extreme weather conditions an increased probability of thermal derates is also important to capture.

[31] S. Murphy, L. Lavin, J. Apt, Resource adequacy implications of temperature dependent electric generator availability, Appl. Energy 262 (2020) 14, https://doi.org/10.1016/j.apenergy.2019.114424.

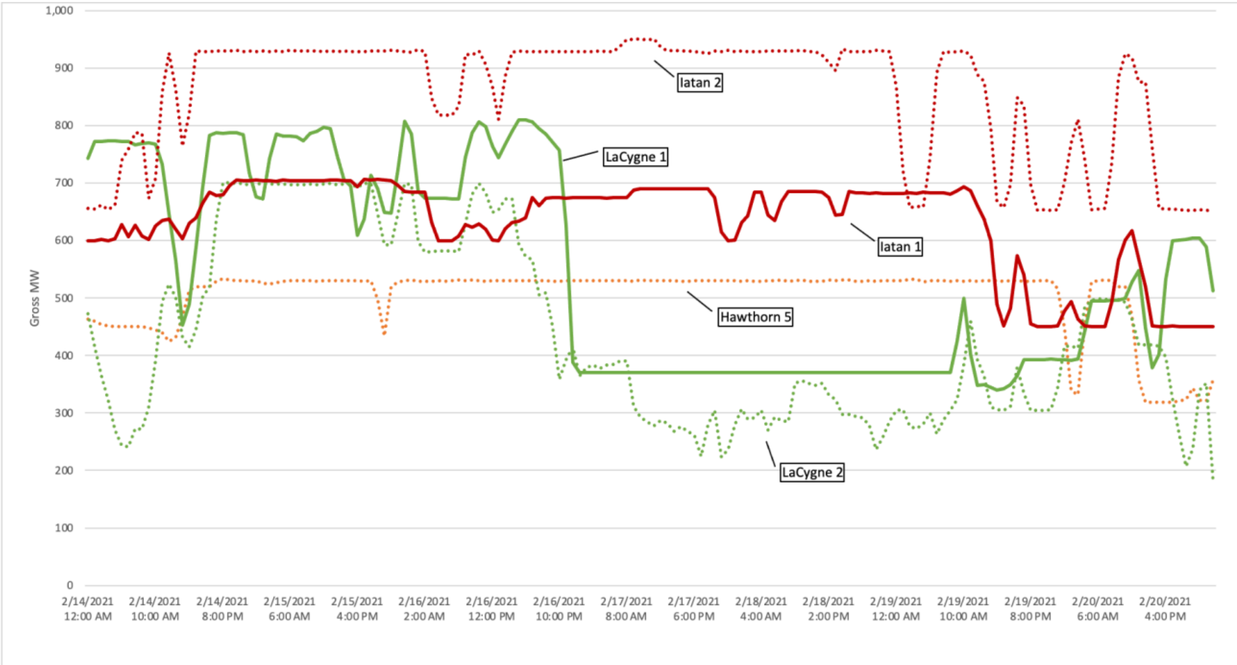


**Figure 10. Operation of Evergy Metro's Coal Plants During Arctic Event**[32]

Figure 10 shows the operation of Evergy Metro's coal units during the February 2021 winter event. This data doesn't offer any insight into why the units operated as they did, for example whether they operated up and down in response to energy price signals or because of equipment challenges. However, Evergy CEO David Campbell stated during a workshop at the Kansas Corporation Commission on May 24, 2021 that its coal units "performed well, it had challenges. The coal fleet definitely struggled with some of this, particularly as the weather event persisted, we had freezing coal issues…but overall the fleet performed well. We literally had staff out on coal piles overnight breaking up coal because you have to pulverize it to feed it to the boiler."[33] Figure 10 shows that the operation of the LaCygne units dropped off starting on February 17th and it may be that he was referencing those units. Either way, the partial or full loss of a thermal unit during extreme weather is an important dynamic to capture in resource adequacy analyses.

No resource adequacy analysis, nor IRP for that matter, of which we are aware captures the decrease in demand during extreme weather arising from weatherizing homes. During a winter weather event there is typically less commercial and industrial load because schools are closed, businesses are closed, etc. And there is, therefore, more residential load because most people

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[32] Coal plant generation data from EPA Air Markets data.

[33] Sustainability Transformation Plan workshop at the Kansas Corporation Commission available at https://www.youtube.com/watch?v=LH3bliz_-mo starting at about 6:12:00.

are at home. In the case of SPP, extreme weather during the February winter storm drove demand from its peak in the prior week of 40,935 MW to what would have been an estimated peak of 47,000 MW, an increase of 15%, but for conservation calls and other activities to reduce load.[34]

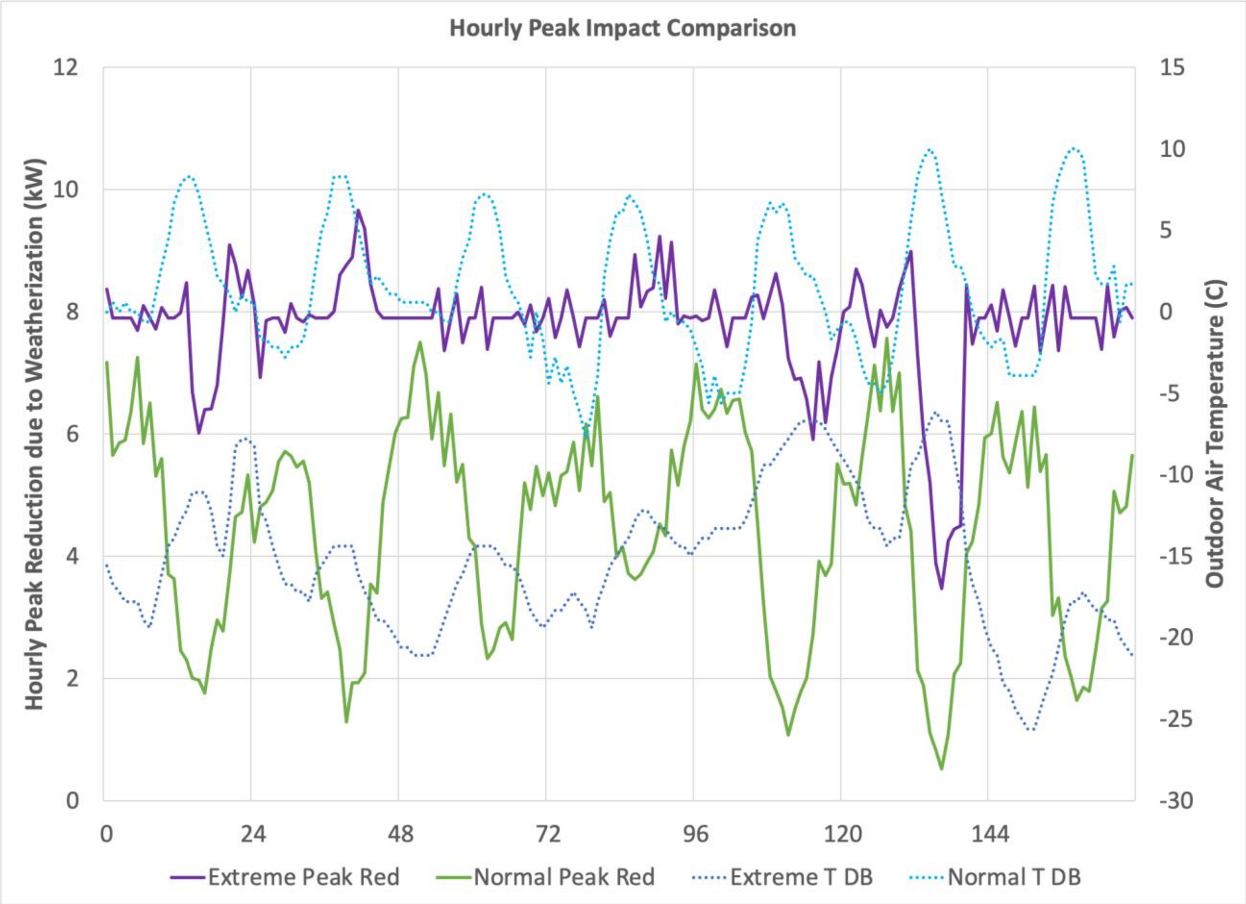


**Figure 11. Hourly Peak Reduction Due to Weatherization[35]**

Residential energy efficiency in particular has an important role to play here because it helps dampen those peaks. Figure 11 shows the performance of a reasonably weatherized home in Kansas versus an unweatherized home, both of which utilize electric baseboard heating under normal and extreme winter weather conditions. The dotted lines correspond to the dry bulb temperature during the week in question, which is not the February 2021 storm week, but rather an "extreme" week shown here that is actually a bit warmer.

[34] "A Comprehensive Review of Southwest Power Pool's Response to the February 2021 Winter Storm: Analysis and Recommendations". Southwest Power Pool. July 19, 2021.

[35] Developed by the Cadeo Group.

The green line shows the difference in demand between the weatherized and non-weatherized home during normal winter conditions. Not surprisingly the weatherization reduces the home's demand. However, the difference between the weatherized and non-weatherized home becomes even greater and notably so, during the extreme winter weather week. As stated previously, this dynamic is not captured in any resource adequacy or IRP analysis of which we are aware, but it is an important one. Increasing frequency and severity of weather events is making it more and more difficult to plan for those events and if we are not modeling load's ability (or inability as the case may be) to respond we are missing a key piece of the puzzle.

Most resource adequacy analyses also exclude any representation of fuel supply interruptions. During the February event, gas plants across the country had difficulty in procuring natural gas for any length of time and some resorted to using fuel oil, if available. Additionally, several coal plants experienced coal pile freezing that caused them to run a partial output. Fuel supply dynamics are normally not represented in resource adequacy analyses and fuel is assumed to be fully available and/or available at prices that are typical for the period.

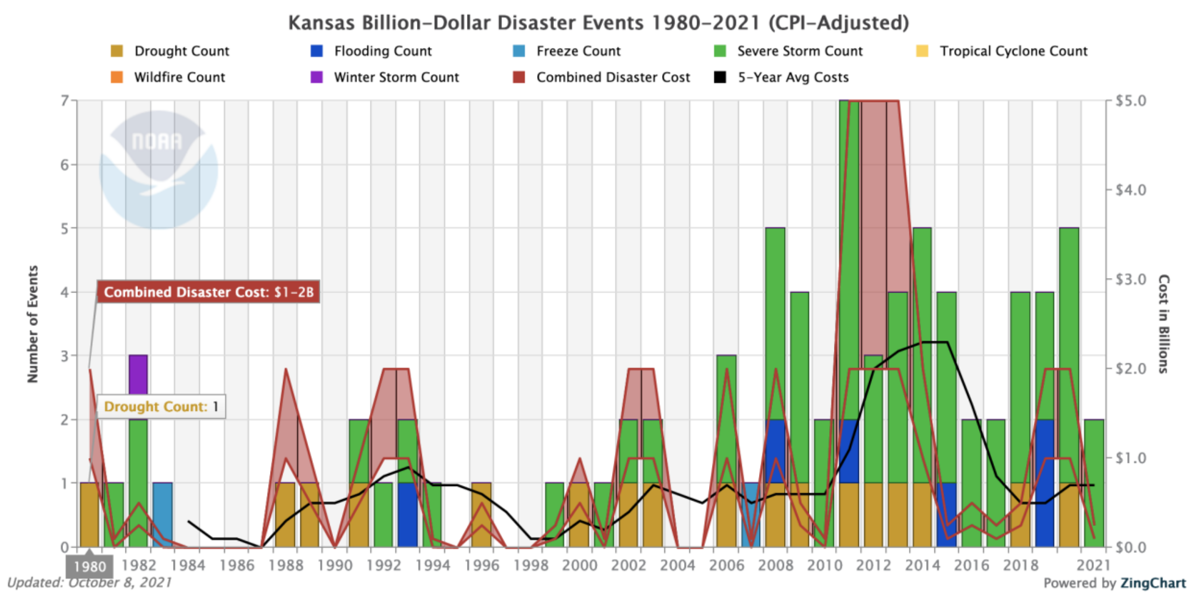


**Figure 12. Billion Dollar Disaster Events in Kansas[36]**

Finally, except to the extent that some level of climate change is already captured in historical datasets, resource adequacy analyses miss the multi-faceted impacts of climate change on electric systems. They miss their increased frequency and severity, their impact on power line ratings, on the ability of generators to operate, and their impact on load. Though it's not possible attribute any one event or its severity to climate change, Figure 12 shows that expensive weather and climate related events are becoming more frequent and more costly in

NOAA National Centers for Environmental Information (NCEI) U.S. Billion-Dollar Weather and Climate Disasters (2021). https://www.ncdc.noaa.gov/billions/time-series/KS

Kansas, just as they are in the rest of the country. Increased frequency and severity of weather events both introduces new uncertainty in resource adequacy analyses but also means that decarbonization is an important reliability strategy.

# 6 Engagement with Evergy

Following the completion of our modeling in EnCompass, we reached out to Evergy to schedule a meeting to present our results to them. That meeting was held on August 24, 2021, and Evergy's planning team was able to ask a number of questions and offer comments. We have also since followed up with Evergy providing them all of our data files and answering additional clarification questions.

Evergy had the following areas of concern:

1. Monetization of the ITC;
2. The degree to which Evergy can build, acquire, and/or interconnect the amount of solar added in the NEE Plans;
3. Lack of an Iatan 2 transmission upgrade cost associated with its retirement; and
4. Reliability of the NEE Preferred Plan.

Regarding the monetization of the ITC and as discussed in Section 3.3.1, we view this as an entirely solvable issue. We know of numerous utilities who have found a pathway to monetize the ITC and fully capture its benefits for customers. We know of no reason Evergy would not be capable of doing so as well and so we stand behind the assumptions we've made about treatment of this tax credit.

Evergy had concerns about how much solar it can build, acquire, and/or interconnect, particularly in the near term. Certainly, there is some physical and political limit, an infinite amount of this resource cannot be acquired. However, we don't see evidence in Evergy's IRP filing that is has fully tested the options available to it or supported the limits it imposed in its own analysis. For example:

1. A recent study by the Brattle Group on behalf of the WATT Coalition found that dynamic line ratings, advanced power flow control, and topology optimization could enable Kansas and Oklahoma to integrate 5,200 MW of additional wind and solar currently in the interconnection queues by 2025.[37] Taking advantage of these technologies would likely require action at SPP, but they are actions that Evergy can have a role in promoting.
2. Evergy's own solar solicitation yielded thousands of megawatts of projects with in-service dates in the next two – three years.

[37] https://watt-transmission.org/wp-content/uploads/2021/02/Brattle__Unlocking-the-Queue-with-Grid-Enhancing-Technologies__Final-Report_Public-Version.pdf90.pdf

3. There are over 9,000 MW worth of solar in the Definitive Interconnection System Impact Study ("DISIS") stage in SPP's queue, suggesting that there is significant interest amongst solar developers in Evergy's footprint. [38]
4. Evergy has not fully explored utilization of the Surplus Interconnection Service under the SPP OATT in Section 3.3 of Attachment V. Given natural gas and oil peaking stations represent about 26% of Evergy's generating resources, the ability to integrate new wind, solar and batteries at those locations without incurring any additional interconnection costs as a result of Surplus Interconnection Service is a promising path forward.

Regarding the Iatan 2 transmission upgrade cost at retirement, we agree that a cost is likely to be necessary given the size and location of the unit. Since Evergy could not supply us with that cost we estimated the cost to convert Iatan 2 to a synchronous condenser and we included that in an updated PVRR calculation given in Section 4.9.

With respect to reliability, this is an important and difficult question to answer for all power systems at present. We know, for example, that the system SPP had on February 15, 2021 was not capable of supplying all load. The NEE plans meet the same SPP reliability requirements that Evergy's system does and would under its Preferred Plans, but that reassurance is no longer sufficient in either case.

We think this issue deserves attention through development of data to at least create a meteorologically consistent scenario that accurately captures the impacts across generators and load. Such data would help address the issues we discussed in Section 5.2 of this report. With some of those improvements, Evergy's next IRP filing could include a more robust assessment of resource adequacy in a framework that allows for evaluation of many different types of plans, not just its preferred plans. At present, given the information Evergy has shared with us in discovery and in its IRP, there is no methodology that would allow the Commission and stakeholders to fairly evaluate the reliability of resource plans of differing makeups.

# 7 Recommendations

## 7.1 Modeling Methodology

### 7.1.1 Capacity Expansion and Production Cost Modeling

Evergy's modeling methodology for this IRP relied on the development of resource plans by hand and then the use of MIDAS to perform the hourly production costing of those plans. NEE and EFG expressed concern about this approach in the comments filed for the December 18, 2020, stakeholder workshop in Kansas and attached to this report as Appendix A. NEE and EFG

[38] SPP GI Queue as of 9/16/2021.

urged Evergy to move to a modeling platform that would be capable of performing capacity expansion to determine optimal plans, and then utilize that model to also simulate the hourly dispatch of those plans. In addition, NEE and EFG recommended a stakeholder process that would help Evergy choose a new model to use in future IRPs. It is our understanding that Evergy will be moving to the PLEXOS model, which can perform capacity expansion and production cost modeling. In other jurisdictions, we have encountered some transparency issues with PLEXOS because it cannot export its user guide and may or may not be able to export all modeling input and output files. We've made our files fully available to Evergy. With an EnCompass license, Evergy could execute exactly the same simulations we performed. If Evergy is committed to utilizing PLEXOS in its future IRPs, then we would very much like to see it commit to a similar process that ensures stakeholders can replicate its analysis and fully vet its modeling. The process of asking multiple discovery questions about individual pieces of its modeling was cumbersome and didn't lend itself to creating a comprehensive dataset quickly nor to understanding all aspects of its MIDAS modeling including how its simulation settings and model capabilities would influence the results. Finally, PLEXOS's vendor, Energy Exemplar, is starting to make project licenses available to intervenors for $4,000 without training and support. We hope that this will also be an option for future Evergy IRPs.

### 7.1.2 Critical Factors and Risk Analysis

As stated in Kansas' IRP Framework:

> *[P]art of the purpose of the IRP Process is to provide (l) resource modeling that identifies the portfolio of resources that meets customer requirements at the lowest reasonable cost given an uncertain future, and (2) to provide an optimal portfolio that is flexible and robust as determined by input sensitivity analyses and contingent scenario analyses.*

We have concerns about Evergy's approach to capturing risk factors within its resource planning analyses. Evergy identified load, natural gas, and $CO_2$ price as the critical factors to which it would assign endpoint probabilities and it created 27 different endpoints (3 load x 3 natural gas x 3 $CO_2$). Our concerns about this approach lies in the considerable complexity of determining endpoint probabilities to be assigned to each critical factor and how those critical factors are paired together as well as a lack of support for the probabilities assumed in Evergy's IRP. Volume 6 of the IRP says that "These probabilities were assigned by the Operations Executive Leadership team after review and discussion of the various forecasts."[39] Based on the probability assignments that were shown in Table 2, we are unsure how it was determined that the $CO_2$ price critical factor had a 20% probability assigned for the low and high cases or why load growth and natural gas were assigned a 35% probability for the low case and a 15% probability for the high case. Given the numerous market, technological, regulatory and political drivers of key inputs such as load, gas prices, and $CO_2$ prices, developing probabilities is a non-trivial task that must be well supported and transparently described.

[39] Evergy Metro IRP Volume 6: Integrated Resource Plan Risk Analysis, page 129.

The Kansas IRP Framework specifically contemplates the use of scenario testing combined with sensitivity analysis to evaluate the performance of portfolios and we would recommend that Evergy adopt this approach over its current methodology. Sensitivities can be modeled to isolate and understand the impact of single assumption changes, i.e., a change in load, capital cost, market price, $CO_2$ price, or fuel price. Scenarios can also be modeled that reflect changes in energy policy, tax policy, cost trends, etc. so that the Company is not simply mixing and matching factors as it has done in this IRP, but providing a rationale for why a particular future is worth evaluating. This approach would also be more consistent with the Kansas IRP framework which asks utilities to model "changes in regulatory milieu" at the state and federal level.

If Evergy does use PLEXOS going forward it will have the capability to do probabilistic modeling. We often see the misuse of probabilistic modeling in IRPs because that modeling isn't being tested for convergence (statistical significance). It is often not based on probability distributions that have been developed with numerical support, e.g. constructing hypothetical probability distributions of $CO_2$ pricing without any underlying data. Sometimes it probabilistically tests variables that could be better represented as sensitivities, e.g. capital cost. We would strongly urge Evergy *not* to use probabilistic techniques just for the sake of using them, but to make sure they are analytically robust, supportable with data, and statistically significant.

## 7.2 Supply Side Resources

### 7.2.1 Modeling Solar Hybrid and Standalone Storage Resources

None of the Alternative Resource Plans presented in Volume 6 of the IRP suggest that solar hybrid or standalone storage resources were included in Evergy's plans. The highlights section in Volume 4 indicates that "Candidate generation resources that passed screening included combustion turbines (CT), combined cycle (CC), wind, battery storage, and solar options and were made available as new generation resources in Integrated Analyses."[40] Despite being passed on to the Integrated Analyses, it does not appear that Evergy modeled any Alternate Resource Plans that contained new battery storage or solar hybrid resources. This could be due to difficulties with representing these resources in the MIDAS and may be resolved with Evergy moving to a new modeling platform. Given the results of our modeling, we recommend that Evergy evaluate both standalone battery storage and solar + storage hybrid resources. We also recommend that Evergy consider long duration and multiday storage as a supply side resource option in future IRPs. Doing so would allow Evergy to comply with the Medium-Run Futures Expectations requirements which seem to require Evergy to evaluate cost-effective electric storage.

[40] Evergy Metro Volume 4: Supply-Side Resource Analysis, page 6.

### 7.2.2 Costs of New Resources

Evergy's cost assumptions for new solar resources assumed utility owned resources that would receive tax normalization and no monetization of the ITC. Utilities in other jurisdictions have modeled the assumption of monetization of the ITC, irrespective of whether they are going to own the resource or not. We strongly believe that Evergy ought to do the same so that it can fairly represent ITC-eligible resources and so that it is not unduly constraining the creation of a least cost plan for customers.

We also recommend, to the extent possible, the use of RFP bids to characterize the cost of new resources. We had hoped to do exactly this with the responses to Evergy's solar RFP, but the responses were given to us in a manner that made it very difficult to put them in apples to apples terms and evaluate them. In the absence of availability of market price data, we recommend utilizing the NREL ATB for renewable and storage resources.

### 7.2.3 Limits on New Resources

Since Evergy did not use a capacity expansion model for this IRP, there were no constraints placed on resources that would limit the optimization. However, if Evergy is moving towards using PLEXOS for future IRPs, it will be important for Evergy to discuss model settings, constraints, and inputs during the stakeholder process.

## 7.3 Coal Plant Retirements

Given the results of our modeling, we recommend that Evergy evaluate optimized retirement dates for its coal plants in future IRPs. We believe optimized retirement dates and corrections to the supply side resources Evergy modeled in this IRP, would have resulted in the selection of a different Preferred Plan. The modeling for the next IRP should critically evaluate the Jeffrey units, particularly if there are anticipated environmental retrofits at those units, as well as the life extension of the LaCygne 2 unit from 2029 to 2039.

## 7.4 Demand Side Management

We have several recommendations related to Demand Side Management ("DSM"). These recommendations include:

1. Conduct an MPS that includes the Kansas service territory and use a stakeholder process to support development of the MPS,
2. Model higher levels of energy efficiency across all operating companies,
3. Account for avoided transmission and distribution ("T&D") and other monetizable benefits, and

4. Account for marginal, not just average line losses.[41]

EFG staff have participated in stakeholder processes for MPS development in other jurisdictions and have found that it has improved buy-in to the final MPS, enhanced assessment of emerging technologies and different program designs such as upstream incentives, and brought transparency to a key input to IRPs.  We would recommend a similar process here.

It's important to note that MPSes are inherently conservative estimates of energy efficiency potential.[42] Where there is little history of energy efficiency, as is the case in Kansas, an MPS can help stakeholders understand the landscape of energy efficiency potential, but they are by no means a cap on the level of EE that can be achieved.  We do not advocate for an MPS to characterize savings potential in Kansas just for the sake of conducting an MPS.  Instead, the components of the MPS like an appliance saturation survey would help make clear the opportunities for utility-sponsored savings programs. The value of an MPS is very much influenced by its quality and the manner in which it is applied (or not) to the IRP modeling. We strongly encourage Evergy to utilize the stakeholder process to vet its methodological approach not just to the MPS, but to its utilization in IRP modeling. EFG has significant experience in this area and would like to help Evergy navigate the pitfalls that we've seen other utilities encounter and narrow the scope of potential disagreements about how this important analysis is conducted.

For this IRP, Evergy evaluated a limited number of different energy efficiency levels. Since our modeling results show some cost savings from modeling a higher level of energy efficiency than Evergy assumed, we believe that Evergy should have explored at least this level of energy efficiency in its IRP and should do so for future IRPs.

We would also like to reiterate the comments that NEE and EFG filed on Evergy's Kansas stakeholder workshop held on January 22, 2021,[43] related to accounting for avoided transmission and distribution benefits and line losses. One of the benefits of energy efficiency is that it avoids costs that supply-side generator cannot such as T&D costs. Most IRP models do not have a way to explicitly include avoided T&D costs, but those avoided costs can be captured as a reduction in energy efficiency program cost.

Most market potential studies define potential at the meter, *i.e.*, as a reduction in sales. However, IRP modeling is conducted at the generator.  So, in order for EE to be correctly

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[41] Lazar, Jim and Xavier Baldwin. "Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements." August 2011. Available at: https://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-eeandlinelosses-2011-08-17.pdf

[42] Kramer, Chris and Glenn Reed. "Ten Pitfalls of Potential Studies." Regulatory Assistance Project. November 2012. https://www.raponline.org/wp-content/uploads/2016/05/energyfutures-kramerreed-tenpitfallsesdraft2-2012-oct-24.pdf

[43] Those comments are attached to this report as Appendix B.

accounted for in an IRP it must be grossed up to account for line losses between the generator and meter. Oftentimes, EE savings are grossed up based on an average line loss rate, *e.g.*, 7 percent. However, energy efficiency saves energy on the margin, not on average, and therefore the marginal line loss rate should be applied. As the Regulatory Assistance Project puts it:

> *There are two types of losses on the transmission and distribution system. The first are no-load losses, or the losses that are incurred just to energize the system – to create a voltage available to serve a load. Nearly all of these occur in step-up and step-down transformers. The second are resistive losses, which are caused by friction released as heat as electrons move on increasingly crowded lines and transformers… Losses increase significantly during peak periods. The mathematical formula for the resistive losses is $I^2R$, where "I" is the amperage (current) on any particular transformer or distribution line, and "R" is the resistance of the wires through which that current flows. While the "R" is generally constant through the year, since utilities use the same wires and transformers all year long, the "I" is directly a function of the demand that customers place on the utility. Thus, resistive losses increase with the square of the current, meaning losses increase as load increases.*[44]

Therefore, the loss reduction benefit of energy efficiency also increases as load increases. A utility with average line losses of 7 percent could have peak line losses of 20 percent or more. This is a very important benefit of energy efficiency that should be captured in the IRP modeling.

## 7.5 Extreme Weather and Reliability

Under the Kansas IRP Framework, "[W]hat-if' contingency analysis needs to be conducted to determine how flexible and robust each supply option is". This provision can be broadly interpreted, but given the events of February 2021 an obvious "what-if" analysis would look at system operation under extreme weather. A comprehensive analysis to this requirement would look at the performance of all generators under the same weather conditions, the performance of load and DSM under those conditions as well, and would account for decreased/increased capability to move power through the transmission system. Evergy's current analysis (and therefore ours as well) looking at extreme weather merely increases the peak load – we don't believe that is sufficient.

[44] Lazar, Jim and Xavier Baldwin. "Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements." August 2011. Available at: https://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-eeandlinelosses-2011-08-17.pdf

## 7.6 Changes in Evergy Kansas Central Preferred Plan

Evergy's IRP filing on June 3, 2021 stated that the Preferred Plan included the retirement of Lawrence Units 4 and 5 with the addition of 350 MW of solar in 2023. In the Request for Waiver, filed on September 22, 2021, Evergy said:

> *Evergy continued to review its analysis after the IRP was filed and determined that retiring only LEC Unit 4 and continuing to operate LEC Unit 5 on natural gas will result in essentially the same net present value revenue requirement ("NPVRR") for customers as retiring both units, but will also provide reliability benefits. Thus, Evergy's current plan is to retire the coal handling facilities at LEC and retire LEC Unit 4 but operate LEC Unit 5 on natural gas.*[45]

Evergy's Preferred Plan now retires Lawrence Unit 4, operates Lawrence Unit 5 on natural gas, and reduces the amount of solar from 350 MW to 190 MW. The amount of solar that was included in the predetermination proceeding is 190 MW instead of the 350 MW that was included in the IRP. In regards to the lower amount of solar, Evergy said:

> *This reduction is quantity was driven by the availability and maturity of specific solar projects as Evergy moved from the generic solar resources included in the IRP to the procurement process for a specific project and does not reflect a substantive change to the Preferred Portfolio.*[46]

Evergy's change to the Preferred Plan is a significant transparency concern. Evergy's filing was made about a month before comments from stakeholders are due. This leaves stakeholders with insufficient time to understand the consequences of Evergy's changes to the Preferred Plan. Furthermore, we have not seen any supporting analysis from Evergy regarding the change in Lawrence Unit 5's status. Indeed, in her testimony in Docket No.22-EKCE-141-PRE, Evergy's Director of Long-Term Planning Kayla Messamore stated "Analysis related to trade offs between retiring LEC Unit 5 and transitioning it to gas operations will be included in future IRP filings."[47]

Furthermore, Kansas Electric Power Cooperative, Inc. ("KEPCo") submitted discovery to Evergy on August 16th and August 18th (KEPCo 1-03 and 1-05) related to the availability of coal-to-gas conversions as an alternative to early retirement and the impact of interconnection queue backlogs on planned procurements and Evergy's responses do not align with certain statements Evergy made about changes to its Preferred Plan in the Predetermination Petition.[48] KEPCo reported that no updates were provided to the discovery questions asked, which is inconsistent with Evergy's statement that they were able to perform additional analysis showing "essentially the same net present value revenue requirement*"* between retiring Lawrence 5 or operating it on natural gas. As

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[45] Docket No. 19-KCPE-096-CPL. Evergy Kansas Metro and Evergy Kansas Central Request for Waiver.
[46] Docket No. 19-KCPE-096-CPL. Evergy Kansas Metro and Evergy Kansas Central Request for Waiver.
[47] Testimony of Kayla Messamore in Docket No.22-EKCE-141-PRE, page 23, lines 11 – 13.
[48] Docket No. 19-KCPE-096-CPL-Response of Kansas Electric Power Cooperative, Inc. to Request for Waiver (Oct 4, 2021).

KEPCo points out, the IRP Framework Order requires that Evergy "file supporting documents relating to the change for review in advance of its next regularly scheduled compliance filing."[49]

We concur with KEPCo that improvements to the IRP procedures are necessary to increase transparency and enhance stakeholder participation. Although the Commission expressed its expectation "that there will be robust review and scrutiny of Evergy's resource decisions in the open predetermination proceeding," predetermination is limited to a 180-day schedule and is limited to the particular project for which the utility files for predetermination. This process should not be used to circumvent integrated resource planning.[50]

It is challenging for stakeholders to engage in the IRP process and provide meaningful feedback when changes are made to the utility's Preferred Plan a month before those stakeholders will file comments on the IRP and when detailed technical information can only be received through multiple rounds of discovery. While Evergy may state that the changes do not result in a material difference in the NPVRR of the portfolio, it is still important for stakeholders to be able to have access to the supporting analysis for the new Preferred Plan sWe currently lack any meaningful analysis to comment on the conversion of this unit to operation on gas.

# 8 Conclusions

In sum, our resource optimization and production costing of Evergy's operating companies finds that advancing retirement of its coal fleets and adding more renewable and battery storage resources:

1. Significantly lowers costs compared to the Evergy Metro Preferred Plan;
2. Modestly lowers costs than the Evergy Kansas Central Preferred Plan;
3. Produces much greater $CO_2$ emission reductions;
4. Offers the possibility of hundred of millions of dollars in savings from securitization; and
5. Additional energy efficiency modestly reduces system cost.

We appreciate the opportunity to provide this report to the Commission, Evergy, and stakeholders and welcome continued dialogue on all these issues.

[49] Docket No. 19-KCPE-096-CPL-Response of Kansas Electric Power Cooperative, Inc. to Request for Waiver.
[50] Docket No. 19-KCPE-096-CPL, Order Granting Evergy's Request for Waiver (Oct. 28, 2021).

# Appendix A

# Appendix A

**<u>COMMENTS OF THE COUNCIL FOR THE NEW ENERGY ECONOMICS REGARDING EVERGY'S INTEGRATED RESOURCE PLAN STAKEHOLDER MEETING ON DECEMBER 18, 2020</u>**

**Submitted December 31, 2020**

The Council for the New Energy Economics ("NEE") appreciates the opportunity to provide comments regarding Evergy's stakeholder workshop held on December 18, 2020, as part of the integrated resource planning ("IRP") process established by the Kansas Corporation Commission ("KCC" or "Commission") in Docket No. 19-KCPE-096-CPL. The established IRP framework allows stakeholders to comment on presentations from Evergy. NEE believes this framework helps facilitate a collaborative stakeholder process for an IRP.

**A. Brief Introduction**

Energy Futures Group ("EFG") provides NEE's analytical modeling services in this IRP. EFG has deep experience participating in state IRP regulatory proceedings. For example, Anna Sommer, principal at EFG, has provided expert testimony in front of utility commissions in Michigan, Minnesota, Montana, New Mexico, North Carolina, Puerto Rico, South Carolina, and South Dakota. EFG's experience includes capacity expansion and production cost modeling, scenario and sensitivity construction, modeling of supply and demand resources, and review of forecast inputs, such as fuel prices, wholesale market prices, and load forecasts. EFG also has experience reviewing modeling performed using numerous models including Aurora, Capacity Expansion Model, EnCompass, PLEXOS, PowerSimm, PROSYM, PROMOD, SERVM, Strategist, and System Optimizer.

**B. Transparency**

Based on our experience, the best results come from a collaborative process between the utility and stakeholders. Proprietary information that is not shared early with stakeholders that have signed non-disclosure agreements ("NDAs") may preclude significantly better outcomes for ratepayers and shareholders. Economic decisions involving billions of dollars made on behalf of customers, shareholders and other impacted stakeholders should be based on shared and vetted data.

Not only is transparency the foundation of stakeholder participation in IRP workshops, but it is also necessary for the Commission's ability to render informed decisions. In order to ensure full transparency, Evergy should provide stakeholders with all modeling inputs[1] as well as the underlying documentation for those inputs. Sharing this information now would be more efficient and allow stakeholders to provide much more meaningful feedback, thereby potentially improving the IRP filing. Stakeholder participation can add substantial value by weighing-in in a collaborative, solution-oriented manner on methodologies, key inputs and assumptions. It could ultimately improve the quality of the modeling effort, thereby improving the IRP preferred portfolio recommendations. In addition, it is much easier to rectify concerns about inputs now rather than after the modeling has been completed and the IRP filed. NEE understands the delicate nature of confidential and proprietary information, but if stakeholders have signed an NDA, then they should be able to access this information. Given the importance of transparency to creating value during the entire IRP process it is important this be addressed now.

**C. MIDAS Model**

The modeling approach for this IRP process diverges from the manner in which most utilities conduct modeling for an IRP. Evergy is developing fixed portfolios of new resource alternatives and then simulating the dispatch of those new resources, along with existing units, in

[1] Examples of modeling inputs include the capital costs, variable and fixed O&M for all new supply side resources (owned and PPAs); underlying cost and savings inputs for DSM resources, including the Market Potential Study; forecast inputs including load, behind the meter solar and battery, electric vehicle, fuel, $CO_2$, and market price forecasts.

a production cost model[2] called MIDAS. It is NEE's understanding that MIDAS is only capable of performing hourly chronological dispatch of the system's generating assets and does not perform capacity expansion modeling. This means that portfolios are created without the benefit of an optimization modeling tool.[3] The vast majority of utilities of Evergy's size conducting IRP modeling use a model that can economically select resources to create an optimal, economic mix of new resource additions. The models frequently used for IRPs are capable of performing both economic selection of a resource portfolio and then subsequently performing an 8760 hourly dispatch of that portfolio, commonly referred to as capacity expansion optimization. For a number of reasons, an optimization approach is far more preferable than using MIDAS to dispatch pre-determined fixed portfolios. First, it is much more time consuming to construct portfolios by hand. Second, it is difficult for a modeler to manually create portfolios that are truly optimal. It would take significant iteration to develop portfolios that aren't overbuilt with respect to the reserve margin, that add new resources by type and timing in an optimal manner, or fairly evaluate the impact of acquiring more of a modular resource, e.g., energy efficiency, or the need to acquire other resources. In addition, the current approach using MIDAS makes it difficult, perhaps even impossible, to fully evaluate how certain model inputs (such as fuel or $CO_2$ prices) impact the selection of new resources or optimize retirements of existing units. For comparison, models that perform capacity expansion optimization allow stakeholders and decision-makers to utilize a

[2] A production cost model is used to determine how individual generators will dispatch into the electricity grid. Production cost models usually simulate this dispatch on an hourly basis over the planning period. In comparison, other models, are used for both capacity expansion and production cost modeling. Once the model determines the optimal resource mix in the capacity expansion plan, it then dispatches those new resources, along with the utilities' existing resources, in a production cost run. That run simulates hourly dispatch over the planning period.

[3] Sometimes the MIDAS name is used somewhat interchangeably with a legacy version of a model called "Capacity Expansion Model". CEM can optimize a resource portfolio but only if the system is currently in a position of deficit, otherwise an artificially high reserve margin has to be used before the model will create an "optimal" portfolio. This would be another reason not to use MIDAS for resource optimization even if it is theoretically capable of doing so.

model that is capable of performing capacity expansion optimization and production costing, which is important for evaluating and determining the optimal mix of a resources at the lowest cost.

NEE is also concerned that MIDAS is an out-of-date model not capable of performing the types of simulations necessary to evaluate all the resources that are currently available for optimal economic benefit. For example, legacy production costing models like MIDAS oftentimes cannot represent solar hybrid resources. This is for one or more reasons. One is that the model was not designed to simulate batteries, since batteries in these models are often represented as pumped storage facilities which can have limitations such as an inability to charge and discharge based on economics (instead it must use a charge/discharge profile created by the modeler). Thus, available capacity and savings from batteries cannot be adequately evaluated. Additionally, most legacy production costing models cannot represent the initial five-year period[4] during which a hybrid battery must be charged by the solar farm to which it is connected simply because the model has no setting to allow for that configuration. With more up-to-date modeling software, solar hybrid resources are being evaluated in other states' IRPs, and if adequately considered, could demonstrate economic benefit in Kansas. In addition, it is our understanding that the vendor of MIDAS, ABB, no longer supports the software. Indeed, several utilities that previously used MIDAS (Ameren Missouri[5] and Indianapolis Power & Light) have moved to other modeling platforms in their recent IRP filings.

With the Missouri filing date so close, NEE believes it is would not be possible for Evergy to switch to a model that is capable of performing both capacity expansion and production cost

[4] In order for the battery to receive the Investment Tax Credit, it must be charged by the solar resource it is paired with for the first 5 years of the life of the project. After the five-year period, the battery no longer has to be charged by the solar resource and can instead be charged by electricity from the grid.

[5] See pdf page 31 of https://www.efis.psc.mo.gov/mpsc/commoncomponents/viewdocument.asp?DocId=935874877

modeling, allowing an economic evaluation of resource portfolios. As outlined above, NEE has concerns about the use of portfolios developed outside of a capacity expansion model that are then dispatched in a production cost model. As a result of these concerns, NEE recommends that Evergy start the search for a model replacement sooner rather than later. In the search for a replacement model, it is crucial to utilize a collaborative stakeholder process. When utilities in Minnesota needed to select a new IRP model to replace Strategist and System Optimizer, they engaged in a model selection process[6] with stakeholder groups that allowed the utilities and stakeholders to vet modeling platforms they learned about through a Request for Information ("RFI"). Through the input of the group, the number of model vendors was narrowed down to four final candidates. Those candidates were asked to provide presentations and Q&A sessions with the parties involved in the RFI process. In addition, each utility test "drove" the top two software packages before making the final decision based on the utility's individual needs.[7] DTE Energy recently conducted a similar process that was very well received and helped create buy-in to DTE's model choice. NEE strongly encourages Evergy to select a new model to conduct its IRP process, utilizing an approach similar to those conducted in Minnesota and Michigan.

**D. Retirement Dates for Coal Plants**

As explained, it is NEE's understanding that the MIDAS model only includes production cost modeling and not capacity expansion optimization. As a result, Evergy creates its own selection of new resources according to a pre-determined coal plant retirement schedule of the plan being evaluated. This limits the possibility of capacity expansion optimization and the ability to

[6] Minnesota utilities including Xcel Energy, Minnesota Power, Otter Tail Power, and Great River Energy engaged in a joint Request for Information process with Commission staff, the consumer advocate, and environmental intervenors. The RFI process allowed these parties to evaluate and vet model alternatives as a group. The selection of the final software package was made by each utility.
[7] All four Minnesota utilities ultimately chose to license Anchor Power Solutions' EnCompass software.

evaluate the retirement of existing units and replacing the capacity of those units with new resources that are economically favorable, with potential fuel and $CO_2$ cost reductions, if the replacement resources include renewables. NEE understands that the base case plan modeled by Evergy assumes the retirement schedule currently reflected in rates. Thus, an optimized comparison of earlier retirement dates and the accompanying potential economic benefits is not included. Such valuable information for decision-making should be included in an IRP. It is unclear to NEE how the alternative retirement dates modeled under the different plans are chosen. It appears the MIDAS model is not performing a neutral economic analysis. NEE recommends that Evergy provide additional information to stakeholders regarding those factors influencing the alternative, selected retirement dates for the coal plants. It is not clear to NEE if the retirement dates are being driven by planned capital expenditures, or if there are other factors influencing the modeled retirement dates. Understanding those factors may help all stakeholders evaluate potentially avoidable, large capital expenditures and savings available from earlier retirements.

**E. Application of Endpoint Probabilities to Uncertain Factors**

Evergy's proposed methodology for evaluating and ranking alternative resource plans includes assessing the Net Present Value of Revenue Requirement ("NPVRR") results for individual scenarios in addition to the "expected" value of the NPVRR across all scenarios. The expected value of NPVRR approach includes applying an endpoint probability for several different critical factors. Evergy has identified the load forecast, natural gas and $CO_2$ prices as critical factors for this IRP update. Each of these critical factors will be assigned a probability associated for the high, mid, and low cases. Endpoint probabilities of 25% for high, 50% for mid, and 25% for the low cases were assigned.[8] For example, in a scenario with high load growth, high natural gas price,

[8] Slide 19 from December 18th, 2020 Evergy IRP Stakeholder Meeting.

and a high $CO_2$ price, that scenario will have an endpoint probability of 1.6%, which is derived by taking the product of the endpoint probabilities, or .25 x .25 x .25. It is NEE's understanding that the expected value of NPVRR is calculated by taking the average of all resulting NPVRRs weighted by their "probability". We understand the desire to synthesize the results of all the different scenarios, but we do not believe that this approach is a sound one. First, it appears the endpoint probabilities may be determined subjectively for two of the three critical factors ($CO_2$ and gas prices). For that reason alone, it's not clear why assigning probabilities would provide additional, helpful information. Moreover, it may be helpful to evaluate why certain of these factors would occur together. For example, for the December 18, 2020 presentation, the modeling assigns all high cases at 25% probability and all low cases at 25% probability of happening. Instead of using this endpoint probability approach, NEE recommends that Evergy model a smaller number of internally consistent scenarios and then compare the NPVRR of the portfolios evaluated under those scenarios. Sensitivities can then be performed to isolate and understand single assumption changes, e.g., a change in capital cost expectations, a change in load, etc. This approach is much more consistent with that of other utilities.

**F. Inclusion of Additional Resource Alternatives**

During the stakeholder meeting held on December 18, 2020, Evergy discussed preliminary modeling results and indicated that future modeling iterations will evaluate new resource additions that include wind, battery storage, and higher levels of Demand Side Management ("DSM"). The alternative resource plans presented during the December 18, 2020 meeting only included a mixture of solar, combined cycles, combustion turbines, and two levels of DSM. In order to ensure a balanced and economic mix of resources, it will be crucial to evaluate resource plans that also consider solar, wind, battery storage, and hybrid resource alternatives. While Evergy seemed hesitant to model hybrid resources when it was discussed during the stakeholder meeting, NEE strongly believes hybrid resources ought to be included in the evaluation of new resources given the tax benefits gained, and the fact that utilities across a wide range of geographies are acquiring thousands of megawatts of hybrid capacity. Neutral data-based, optimization modeling in those jurisdictions indicates there are economic benefits. NEE would be happy to supply the inputs needed to represent these resources, assuming they can be modeled in MIDAS.

**G. Conclusion**

NEE appreciates the opportunity to work collaboratively with Evergy and stakeholders. In order to ensure that the process yields the best collaborative outcome, it is crucial for all modeling inputs to be made available for stakeholders to review and provide comments. NEE looks forward to sharing additional comments and engaging in constructive dialogue throughout this IRP process.

# Appendix B

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# COMMENTS OF THE COUNCIL FOR THE NEW ENERGY ECONOMICS REGARDING EVERGY'S INTEGRATED RESOURCE PLAN STAKEHOLDER MEETING HELD ON JANUARY 22ND, 2021

**Submitted February 5, 2021**

The Council for the New Energy Economics ("NEE") appreciates the opportunity to provide comments regarding Evergy's stakeholder workshop held on January 22, 2021, as part of the integrated resource planning ("IRP") process established by the Kansas Corporation Commission ("KCC") in Docket No. 19-KCPE-096-CPL. The established IRP framework allows stakeholders to comment on presentations from Evergy. NEE believes this framework helps facilitate a collaborative stakeholder process, improves modeling analysis, and better informs decision-makers.

## A. Transparency

As NEE recommended in the comments submitted to Evergy on December 31, 2020, collaboration and transparency between the utility and stakeholders are essential to ensure the best outcome for an IRP process. During the meeting held on January 22, 2021, NEE requested that several documents, including the Demand Side Management ("DSM") Market Potential Study ("MPS"), the Electrification Market Potential Assessment, and the Behind the Meter ("BTM") Solar and Storage Forecast reports be provided to stakeholders. Following the stakeholder workshop, Evergy provided this information to stakeholders by filing the studies in the open docket at the KCC. NEE appreciates Evergy sharing this information as it will help stakeholders gain a better understanding into some of the important model inputs related to DSM potential, the electrification load forecast, and the impact of BTM solar and storage.

It is clearly beneficial that Evergy is investing in these studies to better characterize these resources. The overall IRP product will undoubtedly be improved. NEE recommends that additionally in the future, Evergy incorporate development of these reports as part of stakeholder engagement. For example, stakeholders engage with the Indiana utilities prior to finalization of the reports, thereby addressing stakeholder suggestions and concerns before the finalization of the report and improving confidence and buy-in into the study results.

**B. Demand Side Management**

Based on the information presented to stakeholders, it is NEE's understanding that Evergy will be modeling DSM for the Kansas service territories based on an extrapolation of information from the MPS conducted for the Missouri service territories. Evergy presented information that the energy efficiency ("EE") levels for Kansas will be based on the Missouri Realistic Achievable Potential ("RAP") level for EE, and the Demand Response ("DR") levels for Kansas will be based on the Missouri DR RAP- level. NEE acknowledges and appreciates that Evergy is modeling new EE and DR resources for the Kansas service territories, since these resources are an important component of a cost-effective energy portfolio. However, in the future, it would be helpful to have Kansas-specific EE and DR studies.

We have just begun the process of reviewing Evergy's DSM potential study and do not yet have feedback on the study itself. However, we do have some feedback to offer about how to model DSM in IRPs and some questions for Evergy.

1. <u>Adding an Additional Level of EE</u>. It is very likely the case, as Evergy stated during the presentation, that starting EE programs in its KS service territories will be cost-effective. Given that, it would be very helpful if Evergy could model a second, higher level of EE to evaluate its cost-effectiveness. NEE strongly recommends that Evergy extrapolate the

Missouri study results for a Kansas Maximum Achievable Potential ("MAP") level also. This will allow KCC stakeholders to evaluate the optimal, potential ratepayer savings and economic benefits available in Kansas.

2. Accounting for Avoided T&D and other Monetizable Benefits. One of the ways in which EE and other Distributed Energy Resources ("DERs") are disadvantaged in integrated resource planning is through the exclusion of a portion of the benefits they provide, including avoided transmission and distribution ("T&D") costs. For example, **Figure 1** shows many of the utility, participant, and societal benefits that EE provides. Because IRP modeling is most akin to a utility or societal view of cost-effectiveness, depending on the jurisdiction, it is those categories of benefits that can be overlooked and should be incorporated in IRPs.

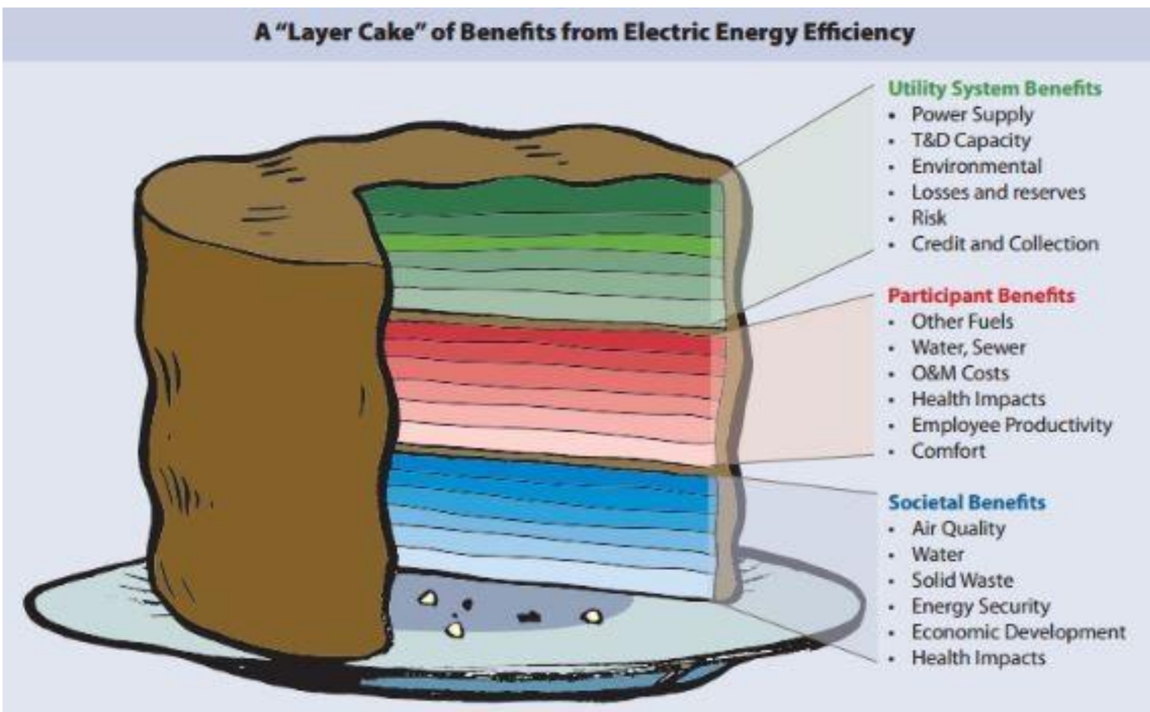


**Figure 1. EE Offers a Wide Range of Utility, Participant, and Societal Benefits**[1]

[1] Lazar, Jim and Ken Colburn. "Recognizing the Full Value of Energy Efficiency." September 9, 2013. Available at: https://www.raponline.org/knowledge-center/recognizing-the-full-value-of-energy-efficiency/

Where an IRP allows EE to reduce both dispatch and new capacity build, the Power Supply benefits are captured. While Power Supply typically constitutes the majority of the utility benefits, the avoided T&D costs are often substantial as well. Though most IRP models do not have a way to explicitly include avoided T&D costs, these can be accounted for as a reduction in modeled EE program cost. Avoided T&D benefits will likely apply regardless of the primary cost-effectiveness test (total resource cost test, utility cost test, societal cost test, etc.) that Kansas would use for screening EE programs and therefore it makes sense to include them in the IRP.

3. Accounting for Line Losses. Most market potential studies define potential at the meter, *i.e.*, as a reduction in sales. However, IRP modeling is conducted at the generator. So, in order for EE to be correctly accounted for in an IRP it must be grossed up to account for line losses between the generator and meter. Oftentimes, EE savings are grossed up based on an average line loss rate, *e.g.*, 7 percent. However, in actuality, energy efficiency saves energy on the margin, not on average, and therefore the marginal line loss rate should be applied for more accurate modeling. As the Regulatory Assistance Project puts it,

> There are two types of losses on the transmission and distribution system. The first are no-load losses, or the losses that are incurred just to energize the system – to create a voltage available to serve a load. Nearly all of these occur in step-up and step-down transformers. The second are resistive losses, which are caused by friction released as heat as electrons move on increasingly crowded lines and transformers… Losses increase significantly during peak periods. The mathematical formula for the resistive losses is $I^2R$, where "I" is the amperage (current) on any particular transformer or distribution line, and "R" is the resistance of the wires through which that current flows. While the "R" is generally constant through the year, since utilities use the same wires and transformers all year long, the "I" is directly a function of the demand that customers place on the utility. Thus, resistive losses increase with the square of the current, meaning losses increase as load increases.[2]

[2] *See* https://www.raponline.org/knowledge-center/valuing-the-contribution-of-energy-efficiency-to-avoided-marginal-line-losses-and-reserve-requirements/ at pages 3 and 4.

Therefore, the loss reduction benefit of EE also increases as load increases. A utility with average line losses of 7 percent could have peak line losses of 20 percent or more. To apply losses correctly to EE savings information about when lines are heavily loaded will be needed, which may be unique for each utility. This is a very important benefit of EE that should be captured in Evergy's modeling.

### C. Electrification Scenario

NEE has concerns about how Evergy is planning to model the electrification scenario load forecast developed in the 1989 Electrification Market Assessment. Evergy stated it will be modeling the electrification load forecast under all of the carbon price and natural gas price scenarios. If Evergy models the electrification scenario in this manner, it is possible that the result will be contrary to the usual intended policy impetus supporting beneficial electrification, which is to electrify certain end-uses to help reduce carbon emissions. Furthermore, widespread electrification would likely occur as a complementary policy regulating greenhouse gas emissions and a failure to reconcile the two could put Evergy in the position of selecting a plan with unrealistically high and therefore costly carbon emissions, simply because of the projected impact of electrification.

NEE recommends that Evergy model the electrification scenario with an explicit limit on carbon emissions, rather than relying on the carbon price to drive the carbon reduction necessary to be modeled with a beneficial electrification scenario. Otherwise, electrification is modeled unrealistically separated from the public policy that would make that electrification happen. Slide 28 of Evergy's presentation illustrates the impact that the top technologies would have in adding to Evergy's load and there is a significant increase starting in 2028 – 2029. If there is no carbon emissions limit placed in the modeling, then this could lead to a counterintuitive result that

Evergy's carbon emissions should increase in order to serve this "decarbonizing" load. We are concerned that this will be Evergy's modeling result case because without capacity expansion optimization modeling runs, the carbon price has no influence on the selection of resources in any given portfolio. With Evergy's methodology of hand-picking resource plans, the high electrification forecast's impact is only to influence the dispatch of units, thereby influencing the NPVRR results.

Additionally, based on the information provided to stakeholders, it appears that the 1898 Electrification Assessment evaluated overall electrification potential in Evergy's service territory and the electrification load forecast was developed based on one level of potential. It may be beneficial for Evergy to explore different electrification pathways in future IRPs that look at varying levels of technology adoption in order to produce an electrification load forecast that is representative of those different levels (such as a low, mid, and high case).

**D. Behind the Meter Solar and Storage**

NEE appreciates Evergy providing the BTM Solar and Storage Forecast Summary Report developed by ICF to stakeholders. NEE is supportive of Evergy's approach to take what is effectively a "utility cost test" view of the costs of BTM solar and storage. Ideally, BTM solar and storage could be treated as any other optimizable DER and assigned avoided cost benefits (like T&D benefits) just as would be assigned to EE. It is NEE's understanding that Evergy intends to model the BTM solar and storage by re-running the NPVRR analysis for each alternative resource plan with the reduced load impact from the high BTM solar and storage forecast. We believe that this is a reasonable first step approach to isolate the impact that BTM solar and storage has on the alternative resource plan. However, in order to evaluate whether Evergy should be offering a BTM solar or storage program to its customers, it would need to have a mechanism within its modeling to back-off other resource additions so that the full potential benefits of BTM resources can be captured. This "avoided capacity" value is most easily captured through the use of a capacity expansion model – a recommendation we made to Evergy in our prior comments.