BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Evergy Metro Inc., d/b/a Evergy Missouri Metro's 2021 Triennial Compliance Filing Pursuant to 20 CSR 4240-22	))))	Case No. EO-2021-0035
In the Matter of Evergy Missouri West, Inc., d/b/a Evergy Missouri West's 2021 Triennial Compliance Filing Pursuant to 20 CSR 4240-22	))))	Case No. EO-2021-0036

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 Missouri Metro and Evergy Missouri West, Inc., d/b/a Evergy Missouri West (together, "Evergy") in the above-referenced cases (the "Evergy IRP Proceedings") pursuant to 20 CSR 4240-22.080(8). 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 Missouri Public Service Commission ("Commission") granted NEE's application to intervene in the Evergy IRP Proceedings on April 26, 2021.

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 Proceedings, 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 Chapter 22 of the Commission's Rules: minimization of the present worth of long-run utility costs. 20 CSR 4240-22.020(9); 20 CSR 4240-22.010(2)(B).

5. As further detailed in the attached Report, NEE has identified several other Concerns relating to Evergy's compliance with Chapter 22. 20 CSR 4240-22.020(6).

These include:

a. Evergy's use of critical factor and risk analysis methodology used to capture risk factors (20 CSR 4240-22.060(6) & (7));

b. Evergy's apparent failure to model any Alternate Resource Plans that contained new battery storage or solar hybrid resources (20 CSR 4240-22.040(4)(B))

c. Evergy's cost assumptions for new solar, wind, and battery storage resources are based on out-of-date data (20 CSR 4240-22.040(2)).

d. Evergy's cost assumptions for new solar resources do not include monetization of the Investment Tax Credit ("ITC") (20 CSR 4240-22.040(1));

e. Evergy's failure to evaluate achievable and beneficial levels of demand side management (20 CSR 4240-22.050(3) & (4));

f. Evergy's inadequate modeling of extreme weather conditions (20 CSR 4240-22.030(8)(B)).

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 Missouri Metro customers 5.01% and Evergy Missouri West customers 9.20% compared to Evergy's Preferred Plan. By refinancing unrecovered investment in early retired plants with securitized debt, NEE's plan could save about 2.75% more for Evergy Metro customers and about 1.50% more for Evergy Missouri West customers.

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

Respectfully submitted,

By: */s/Andrew O. Schulte*
Andrew O. Schulte MBN 62194
900 West 48th Place, Suite 900
Kansas City, Missouri 64112
(816) 691-3731
Fax No. (816) 751-1536
aschulte@polsinelli.com

ATTORNEY FOR THE COUNCIL FOR
THE NEW ENERGY ECONOMICS

CERTIFICATE OF SERVICE

The undersigned hereby certifies that a true and correct copy of the above and foregoing pleading has been emailed this Sepember 27, 2021, to all counsel of record:

/s/Andrew O. Schulte
Andrew O. Schulte

ENERGY FUTURES GROUP

Evaluation of Triennial Resource Planning Filing of Evergy Metro and Evergy Missouri West

Prepared by:

Chelsea Hotaling, Energy Futures Group

Anna Sommer, Energy Futures Group

Kenneth Sercy, Sercy Consulting

Prepared for:

The Council for the New Energy Economics

September 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.

Table of Contents

Table of Figures

Table of Tables

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 Evergy's Preferred Plans;
2. Much greater CO_2 emission reductions;
3. Hundred of millions of dollars in savings from securitization; and
4. Additional energy efficiency modestly reduces system cost.

Our report also summarizes our assessment of how Evergy's IRP complies with the Chapter 22 requirements. Table 1 provides a summary of our areas of concern and deficiency and the proposed remedy. 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. Chapter 22 Deficiencies and Concerns for Evergy's IRP

Title	Deficiency or Concern	Chapter 22 Citation	Proposed Remedy
Policy Objectives	Deficiency	20 CSR 4240-22.010 (2) (B)	Utilize capacity expansion and production cost modeling to ensure minimization of costs
Supply Side Resource Analysis	Concern	20 CSR 4240-22.040 (1)	Utilize market pricing from RFPs or the NREL ATB if market price data is not available
Supply Side Resource Analysis	Deficiency	20 CSR 4240-22.040 (4) (B)	Include solar hybrid resources and battery storage technologies in Alternate Resource Plans
Supply Side Resource Analysis	Deficiency	20 CSR 4240-22.040 (1)	Assume monetization of the ITC to fairly evaluate solar and paired storage
Integrated Resource Plan and Risk Analysis	Concern	20 CSR 4240-22.060 (6) and (7)	Utilize scenario and sensitivity modeling to test critical factors
Demand-Side Resource Analysis	Deficiency	20 CSR 4240-22.050 (3) & (4)	Evaluate the cost-effectiveness of all levels of DSM contained in the Company's Market Potential Study
Load Analysis and Load Forecasting	Concern	20 CSR 4240-22.030(8)(B)	Evaluate supply and demand-side resource performance under the same meteorological conditions that underpin the extreme weather load forecast

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[1], 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.

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

[1] 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.

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[2]

	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[3], 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 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

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

[3] Evergy Metro includes Evergy Metro Missouri and Evergy Metro Kansas

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[4]	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[5], 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

[4] 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.

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

costs and utilities have expressed concern[6] 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.[7] 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.

[6] 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

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

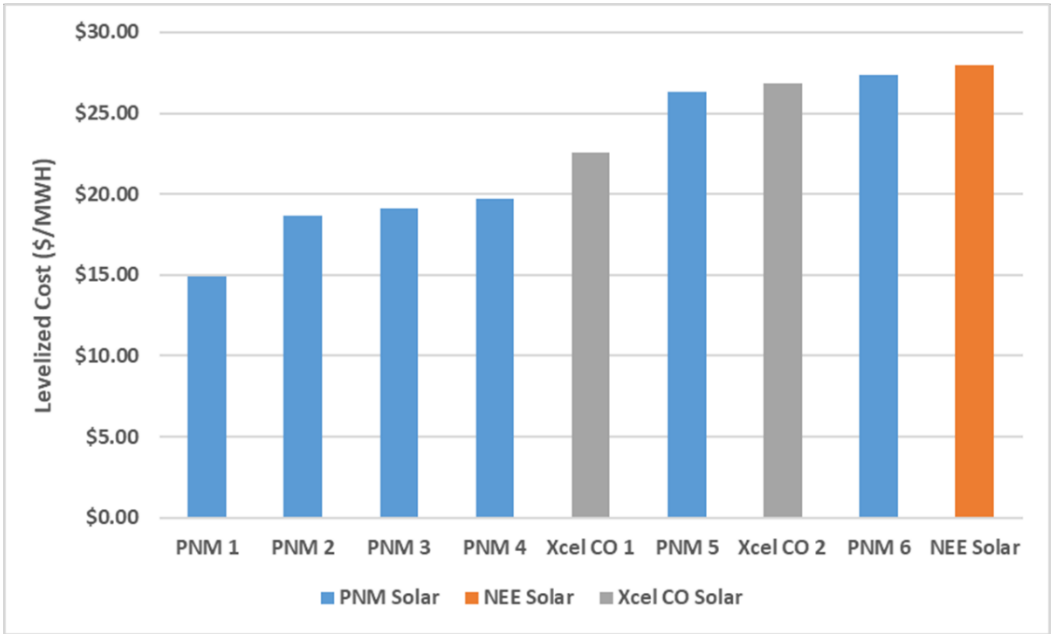

Figure 1. RFP Bids Compared to NEE Solar Cost

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.[8] The market for utility scale batteries has grown dramatically since 2019[9] with thousands of megawatts of

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

[9] 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.[10] 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[11]

	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.

[10] 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
[11] 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.*[12]

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[13] 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.

[12] Evergy's response to NEE 2-28.
[13] 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

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.[14] We also used the load and CO_2 price forecasts that Evergy provided to us in discovery.[15]

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.[16] We set up a market interaction within EnCompass to represent

[14] Evergy discovery response to NEE 1-4.
[15] Evergy discovery response to NEE 3-6 and NEE 2-14.
[16] Evergy discovery response to NEE 2-15.

Evergy's market exchange with the Southwest Power Pool ("SPP"). We also used Evergy's capacity price assumptions for purchases and sales.[17] Evergy's modeling assumed that each operating company was able to purchase or sell up to 100 MW of capacity in any given year. After further discussion with Evergy, it is our understanding that the Missouri West operating company could purchase more than 100 MW of capacity if it came from Evergy Metro so we reflected that in our modeling as well. 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.[18]

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 Missouri West.

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

	Metro	Missouri West
Sales Constraint	452	257

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.[19]

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..

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

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

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[20] 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.

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

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

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 Missouri West 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 Missouri West, Jeffrey 3 retires in 2030 and

Jeffrey units 1 and 2 and Iatan 1 retire in 2039. Table 12 and Table 13 show the expansion plan for Evergy Metro and Evergy Missouri West. Evergy's Preferred Plan includes modest amounts of new solar and wind and several CT additions after 2040.

Table 11. Evergy Metro and Missouri West Coal Plant Retirements in Preferred Plan

Year	Evergy Metro	Evergy Missouri West
2030		Jeffrey 3
2032	LaCygne 1	
2039	LaCygne 2	
2039		Jeffrey 1 & 2
2039	Iatan 1	Iatan 1

Table 12. Evergy Metro Preferred Plan (Capacity in MW)[21]

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

[21] Evergy Metro IRP Volume 7: Resource Acquisition Strategy Selection, Table 1, page 3.

Table 13. Evergy Missouri West Preferred Plan (Capacity in MW)[22]

Year	Solar	Wind	CT
2024	120		
2025		80	
2026		80	
2028	80		
2029	80		
2030	80		
2031	80		
2032	80		
2033			233
2039			233
2040			233

4.4 NEE Preferred Capacity Expansion Plans

NEE's capacity expansion optimization runs produced a plan that result 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 Missouri West Preferred Plan.

[22] Evergy Missouri West IRP Volume 7: Resource Acquisition Strategy Selection, Table 1, page 7.

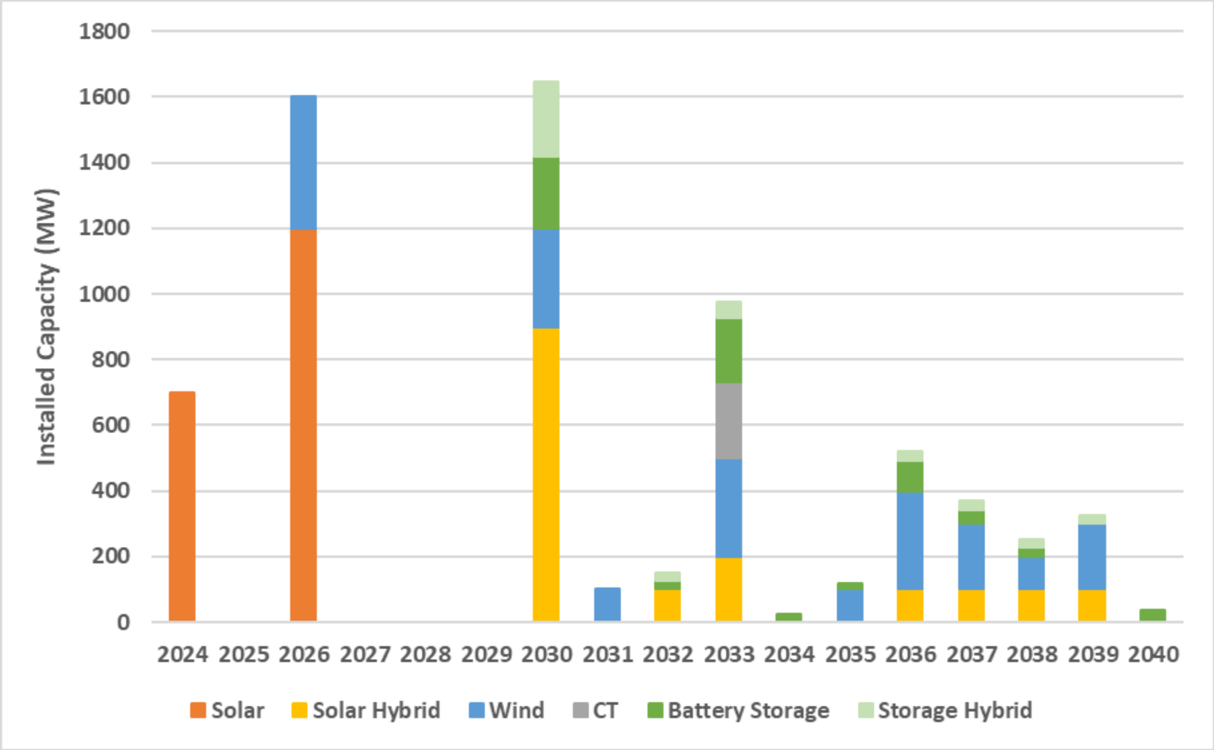

Figure 2. Capacity Expansion Plan for the NEE Metro Preferred Plan (Installed Capacity MW)

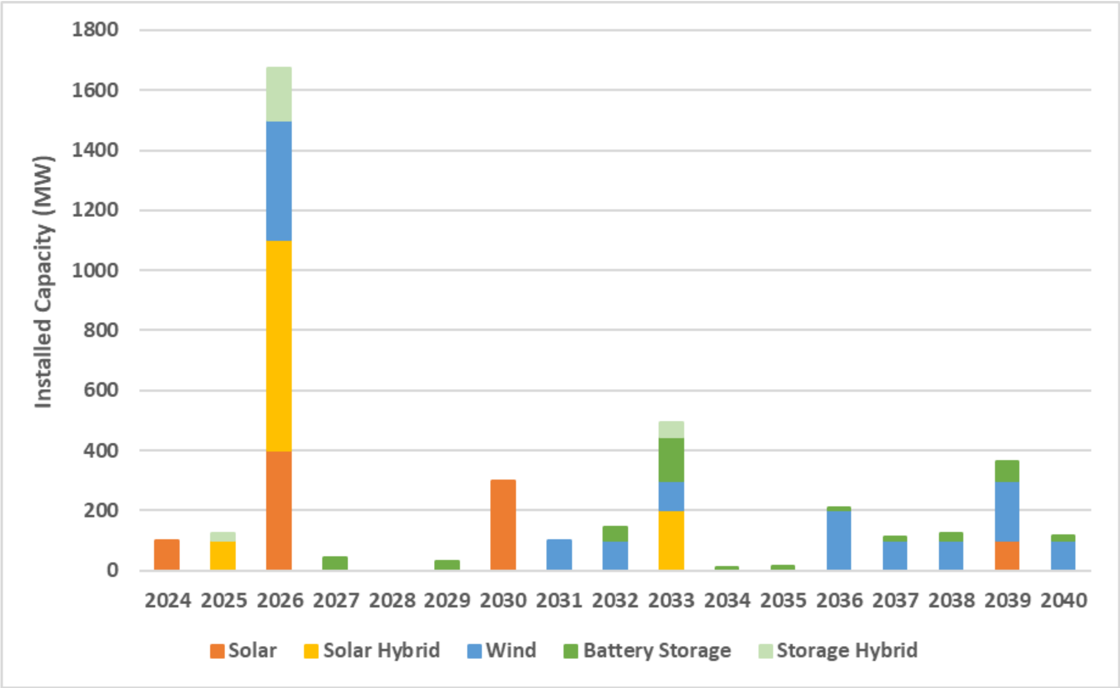

Figure 3. Capacity Expansion Plan for the NEE MO West Preferred Plan (Installed Capacity MW)

Table 14 shows the total installed capacity additions (MW) between 2021 and 2040 for Evergy Metro and Evergy Missouri West in the NEE Preferred Plans. For both Evergy Metro and Evergy Missouri West, 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 no CTs added in the Evergy MO West Preferred Plan.

Table 14. Total Installed Capacity Additions (MW) for Evergy Metro and MO West (2021 – 2040)

Resources	Metro (MW)	MO West (MW)
Solar	1900	900
Solar Hybrid	1600	1000
Wind	2000	1400
Storage	684	417
Storage Hybrid	400	250
CTs	233	0

Table 15 and Table 16 show the load and capacity tables for the NEE Preferred Plans for Evergy Metro and Evergy Missouri West.

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 MO West 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)	1,871	1,862	1,821	1,803	1,785	1,770	1,758	1,750	1,738	1,728	1,733	1,747	1,757	1,767	1,779	1,791	1,799	1,810	1,823	1,837
Existing Resources																				
Nuclear:Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas/Oil:Combined Cycle	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas/Oil:Combustion Turbine	1205	1205	1205	1205	1108	1108	1108	1108	1108	1108	1108	1108	1108	1108	1108	1108	1108	1108	1108	1108
Coal:Conventional	462	462	462	336	336	336	162	162	162	162	162	162	0	0	0	0	0	0	0	0
Renewable:Landfill	0	0	0	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	178	178	178	178	178	178	178	178	178	178	178	141	109	109	109	96	82	60	0	0
Storage:Battery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Contract:Purchase	323	325	328	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Contract:Sale	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Firm Capacity Existing	**2,168**	**2,170**	**2,173**	**1,719**	**1,622**	**1,622**	**1,447**	**1,447**	**1,447**	**1,447**	**1,447**	**1,410**	**1,217**	**1,217**	**1,217**	**1,204**	**1,190**	**1,168**	**1,108**	**1,108**
Net Resource (Need)/Surplus	**298**	**308**	**352**	**-83**	**-163**	**-148**	**-311**	**-303**	**-290**	**-281**	**-285**	**-336**	**-540**	**-550**	**-562**	**-587**	**-609**	**-642**	**-715**	**-729**
New Projects																				
New Wind	0	0	0	0	0	40	40	40	40	40	50	60	70	70	70	90	100	110	130	140
New Solar	0	0	0	50	50	90	90	90	90	120	120	120	120	120	120	120	120	120	130	130
New Solar Hybrid	0	0	0	0	50	160	160	160	160	160	160	160	180	180	180	180	180	180	180	180
New Battery Storage	0	0	0	0	0	0	38	38	65	65	65	107	236	248	261	272	282	302	359	375
New Hybrid Battery Storage	0	0	0	0	23	180	180	180	180	180	180	180	225	225	225	225	225	225	225	225
New CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Capacity Purchase	0	0	0	250	255	0	13	4	0	0	0	0	0	0	0	0	0	0	0	0
Firm Capacity New Resources	0	0	0	300	377	470	521	513	535	565	575	627	831	843	856	887	907	937	1024	1050
Total Firm Capacity	**2,168**	**2,170**	**2,173**	**2,019**	**2,000**	**2,092**	**1,969**	**1,960**	**1,983**	**2,013**	**2,023**	**2,037**	**2,048**	**2,060**	**2,073**	**2,090**	**2,096**	**2,105**	**2,132**	**2,158**
Reserve Margin	**15.92%**	**16.57%**	**19.33%**	**12.00%**	**12.00%**	**18.18%**	**12.00%**	**12.00%**	**14.10%**	**16.47%**	**16.74%**	**16.63%**	**16.59%**	**16.56%**	**16.53%**	**16.72%**	**16.54%**	**16.30%**	**16.93%**	**17.44%**

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 Missouri West. Table 17 shows the PVRRs from our re-simulation of Evergy's Preferred Plans against the NEE Preferred Plans. The NEE Preferred Plans, which contain more coal plant retirements and higher levels of renewables and storage, have significant cost savings when compared to the Evergy Preferred Plans.

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

Operating Company	NEE PVRR ($000)	Evergy PVRR ($000)	% Difference
Metro	$11,970,457	$12,602,399	-5.01%
MO West	$7,050,637	$7,764,550	-9.20%

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.

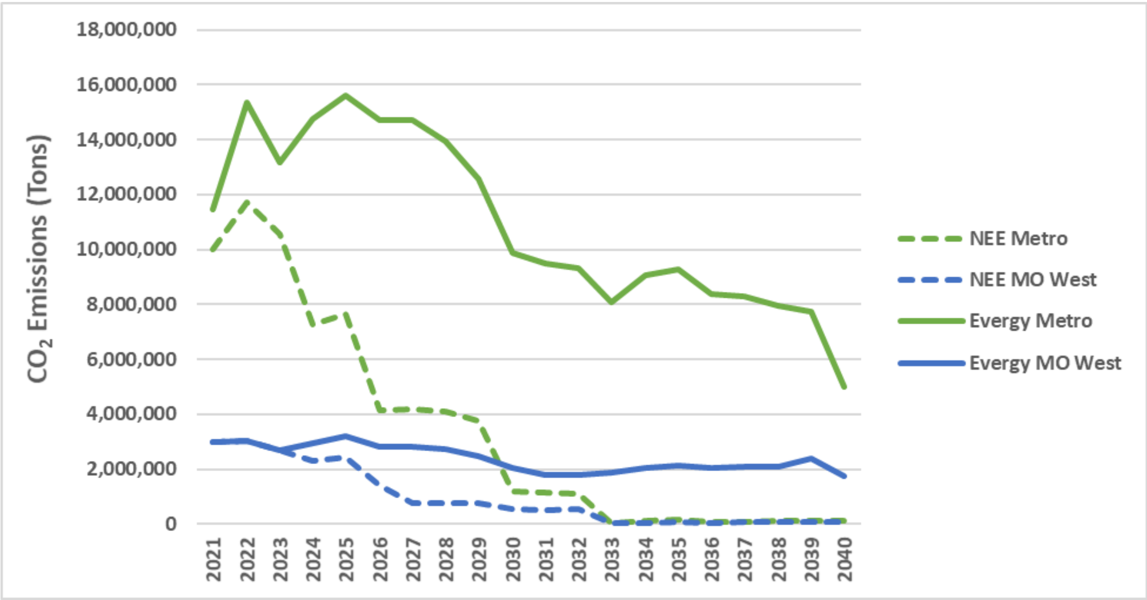

Figure 4. Carbon Emissions of NEE and Evergy Preferred Plans

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 Missouri West Preferred Plan (dashed blue line) achieves an 81% reduction in CO_2 emissions by 2030, and a 98% reduction by 2040. 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 Missouri West Preferred Plan (blue line) achieves a somewhat larger, though still modest, 31% reduction in CO_2 emissions by 2030 and a 41% reduction by 2040.

4.7 Additional Energy Efficiency Scenario

The 2019 Market Potential Study ("MPS") completed for Evergy included energy efficiency savings for 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.[23] The NEE modeling runs included the Realistic Potential Achievable ("RAP") level of energy efficiency savings for each operating company. Table 18 shows the comparison of energy efficiency savings in the RAP and MEEIA scenarios.

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

Table 18. MPS Energy Efficiency Summary of Savings (Annual GWH)[24]

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

We were able to set up the modeling inputs for the MEEIA scenario based on the discovery responses we received from Evergy.[25] Table 19 shows the PVRR comparison of the NEE modeling runs with the RAP level of energy efficiency with the NEE modeling runs with the MEEIA level of energy efficiency savings. The results indicate that there are some cost savings with the MEEIA level of energy efficiency.

Table 19. PVRR Comparison of NEE Plans with the RAP and MEEIA Levels of Energy Efficiency

Operating Company	RAP EE PVRR ($000)	MEEIA EE PVRR ($000)	Difference (%)
NEE Metro	$11,970,457	$11,932,463	-0.32%
NEE MO West	$7,050,367	$7,008,281	-0.60%

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 20 gives the resulting PVRRs and the new difference between plans.

Table 20. PVRR Comparison for Renewable Price Sensitivity

Operating Company	NEE PVRR ($000)	Evergy PVRR ($000)	% Difference
Metro	$12,415,056	$12,939,848	-4.06%
MO West	$7,310,123	$7,829,001	-6.63%

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

[25] 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.

Performing this cost sensitivity confirms that there would still be significant cost savings under the NEE Plans even if the new wind and solar resources were 25% higher.

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 21. PVRR Comparison with Iatan 2 Proxy Transmission Upgrade Cost

Operating Company	NEE PVRR ($000)	Evergy PVRR ($000)	% Difference
Metro	$11,991,241	$12,602,399	-4.85%
MO West	$7,057,295	$7,764,550	-9.11%

4.10 Securitization

New Missouri legislation that was passed in 2021, House Bill 734, enables the use of securitization for cost recovery of remaining plant balances when coal units are retired on an accelerated schedule.[26] 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 Missouri West together, securitization saves approximately $10 million with the Evergy Preferred Plan, and approximately $500 million with the NEE Plan.

[26] Codified at RSMo. 393.1700 *et seq*.

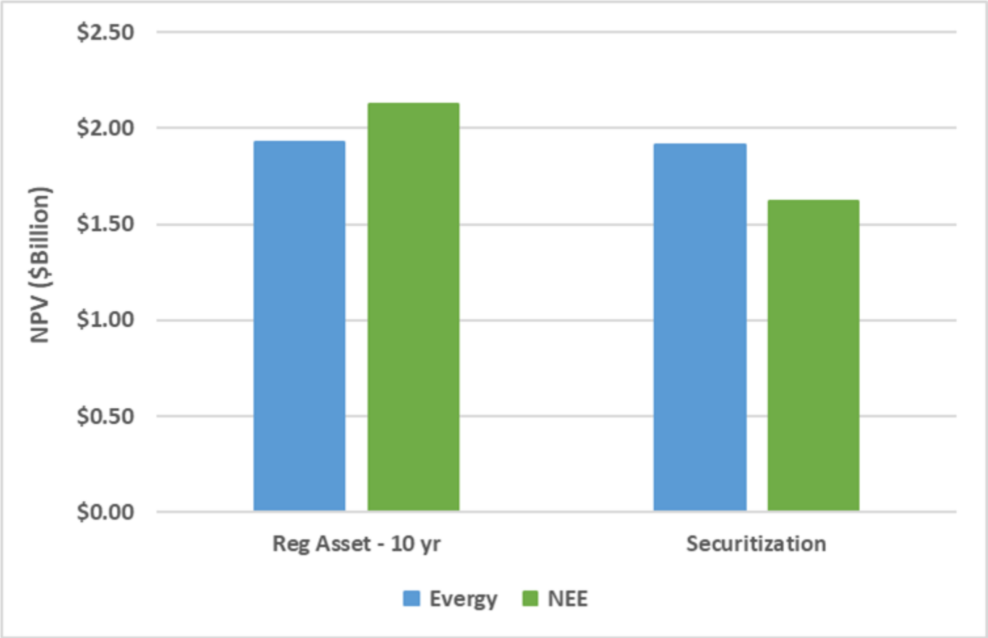

Figure 5. NPV ($Billion) of Regulatory Asset and Securitization for Evergy and NEE Preferred Plans

Figures 6 and 7 illustrate the benefits of securitization relative to the full PVRRs of the plans, and broken out into the two Missouri operating companies. 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 1.5% for Evergy MO West 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 each operating company.

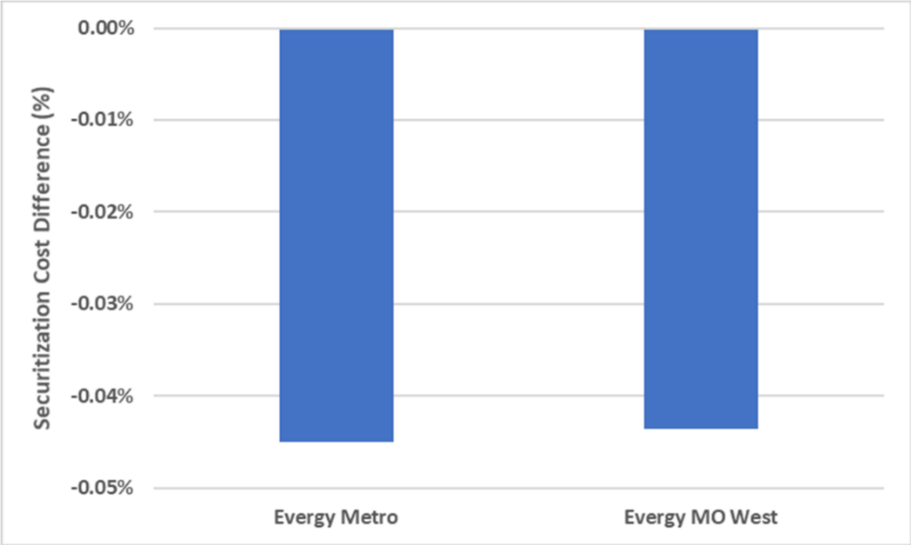

Figure 6. Evergy Securitization and Regulatory Asset Cost Difference (%)

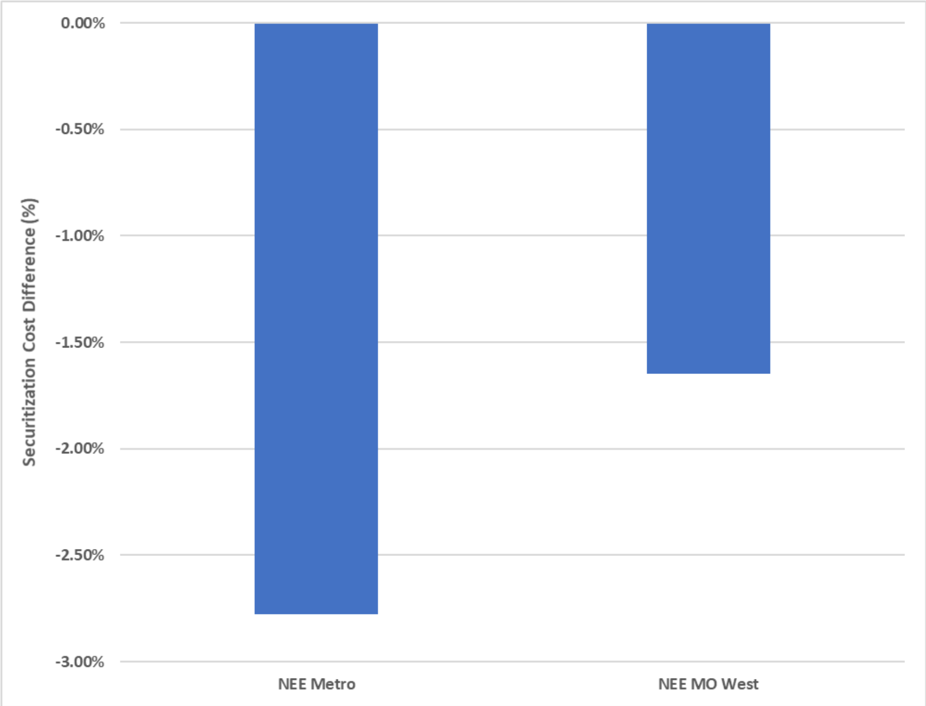

Figure 7. NEE Securitization and Regulatory Asset Cost Difference (%)

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[27] 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.

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

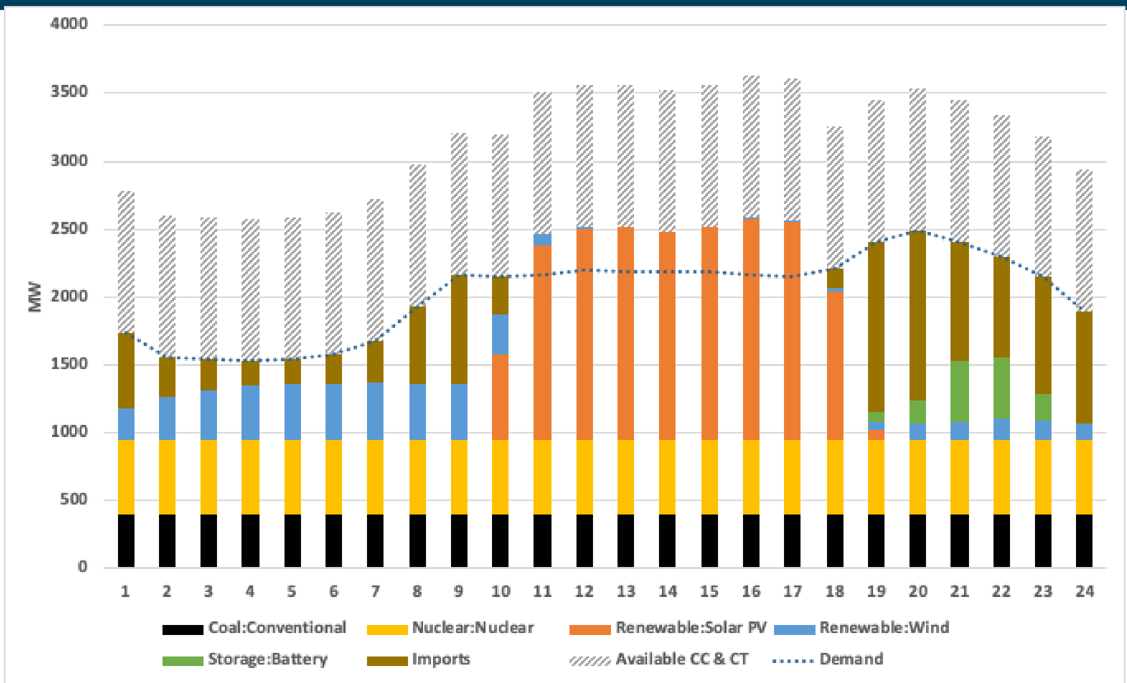

Figure 8. NEE Evergy Metro Preferred Plan Dispatch Under Extreme Weather Scenario

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 CTs 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.

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.

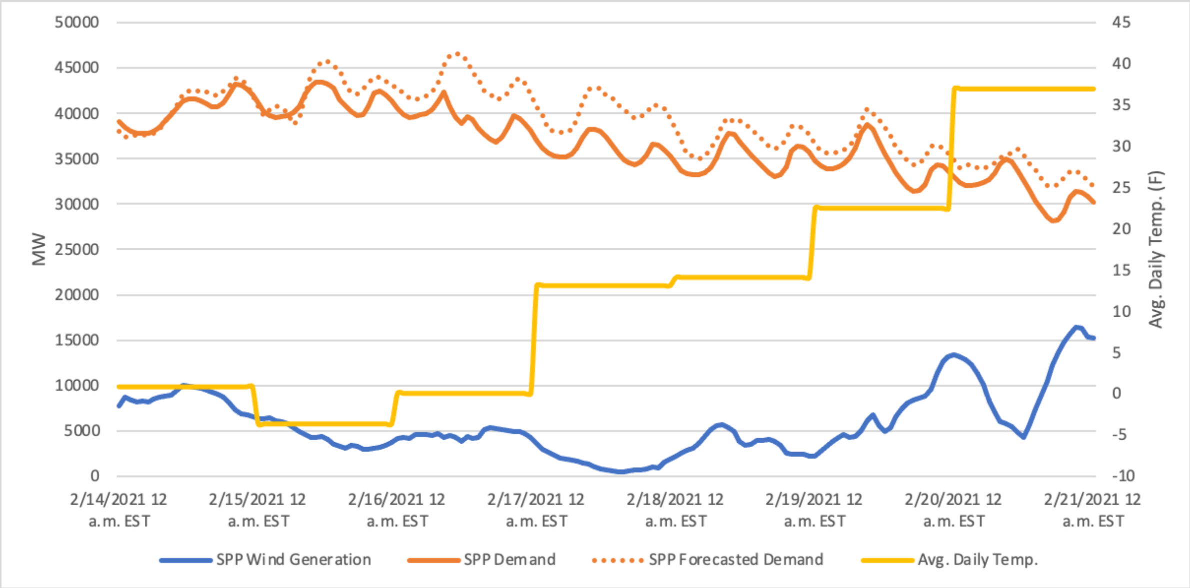

Figure 9. Comparison of Wind Generation, Load, and Average Temperature in SPP During February 2021 Winter Storm

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.[28] Particularly because load tends to increase significantly under extreme weather conditions an increased probability of thermal derates is also important to capture.

[28] 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.

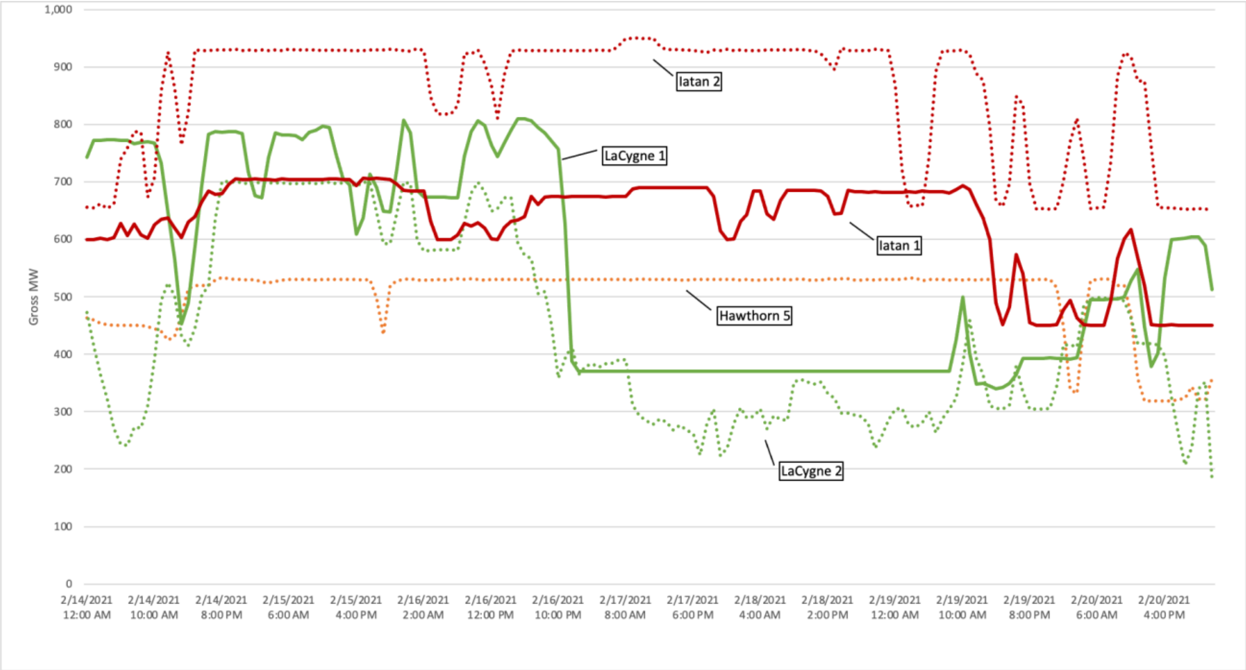

Figure 10. Operation of Evergy Metro's Coal Plants During Arctic Event[29]

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."[30] 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

[29] Coal plant generation data from EPA Air Markets data.
[30] 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.[31]

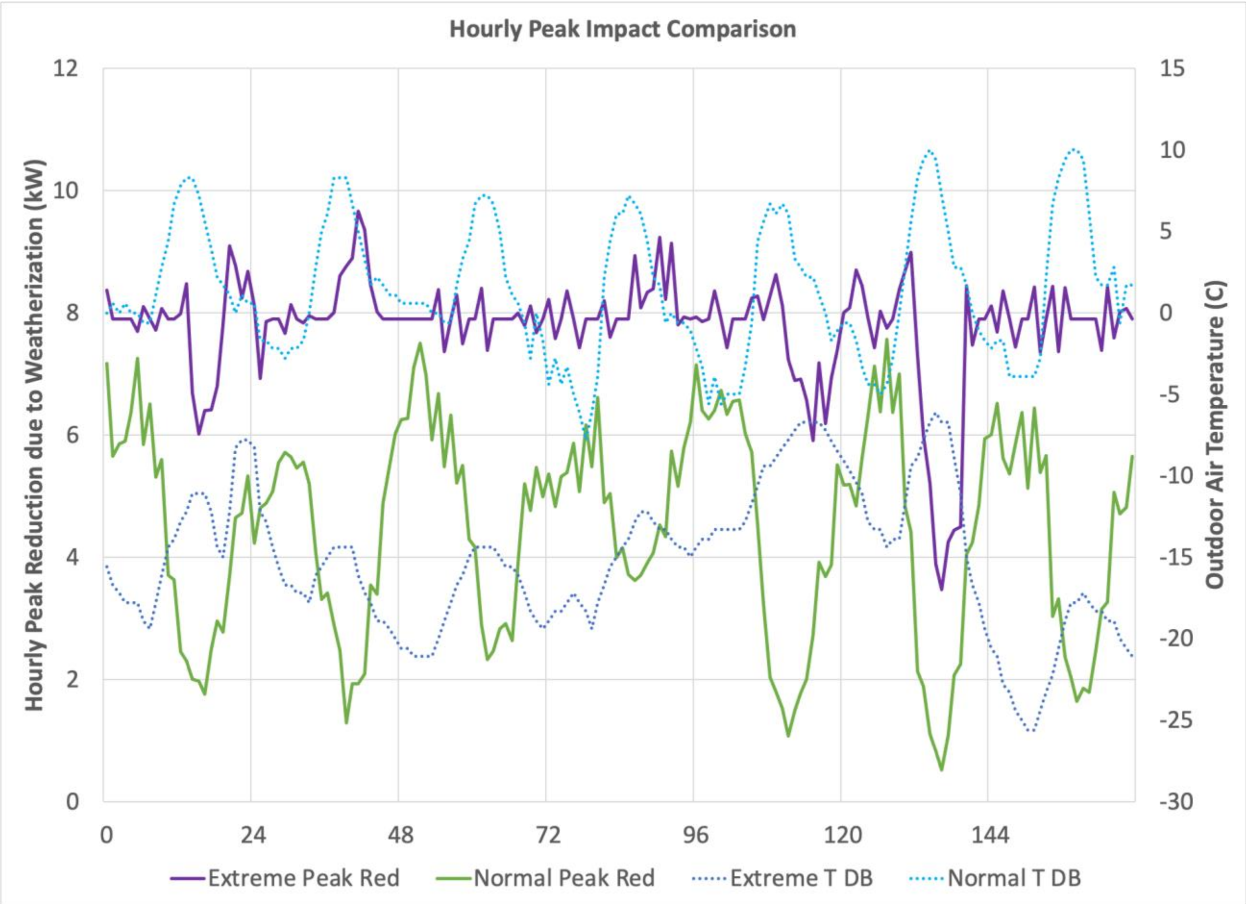

Figure 11. Hourly Peak Reduction Due to Weatherization[32]

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.

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

[32] 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.

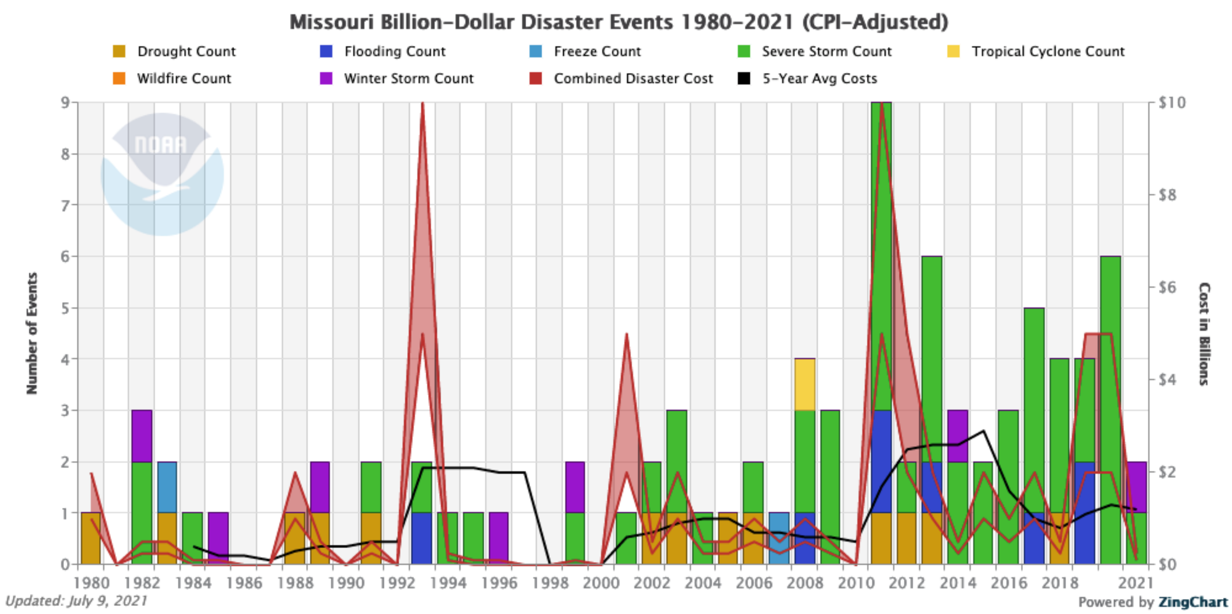

Figure 12. Billion Dollar Disaster Events in Missouri[33]

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

NOAA National Centers for Environmental Information (NCEI) U.S. Billion-Dollar Weather and Climate Disasters (2021). https://www.ncdc.noaa.gov/billions/, expensive weather and climate related events are becoming more frequent in Missouri, 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.[34] 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.

[34] 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. [35]
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

[35] 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

Chapter 22 of the Electric Resource Planning rules require the use of critical factors and endpoint probabilities for risk analysis. Sections 6 and 7 of 20 CSR 4240-22.060 state:

> *The utility shall describe and document its assessment of the impacts and interrelationships of critical uncertain factors on the expected performance of each of the alternative resource plans developed pursuant to 4 CSR 240-22.060(3) and analyze the risks associated with alternative resource plans. This assessment shall explicitly describe and document the probabilities that utility decision makers assign to each critical uncertain factor.*
>
> *The utility decision-makers shall assign a probability pursuant to section (5) of this rule to each uncertain factor deemed critical by the utility. The utility shall compute the cumulative probability distribution of the values of each performance measure specified pursuant to 4 CSR 240-22.060(2). Both the expected performance and the risks of each alternative resource plan shall be quantified. The utility shall describe and document its risk assessment of each alternative resource plan.*

While we understand that Evergy needed to include the critical factor and risk analysis methodology in its IRP to meet the Chapter 22 rules, 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, and 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."[36] 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.

We recommend that Commission rules should be interpreted or modified to allow Evergy and other Missouri utilities to model a smaller number of scenarios and sensitivities so that plans could be compared using the PVRR of the portfolios evaluated under those scenarios and sensitivities. 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 contain several changes to the assumptions, such as a combination of a change in market prices with an associated CO_2 price. We have reviewed many dozens of utility IRPs and similar analyses across different jurisdictions and utilities often model a base or reference case that generally reflects an extension of current trends. Utilities then test those inputs by changing the assumptions. For example, if Evergy wanted to test the impact of a change in natural gas prices, they could fix the Alternate Resource Plan and redispatch the plan under a higher or lower natural gas price or they could reoptimize the plan and see how that change in natural gas price impacts the capacity expansion plan. It would still be able to compare differences in cost across multiple plans and under differing assumptions. If the plan was reoptimized under the different natural gas price, then Evergy could also compare differences in the capacity expansion plans. Cost differences between the base case plans and the sensitivity or scenario can be used to calculate the impact of those factors that changed, such as the load, fuel, or market price forecasts.

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.

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

We would ask the Commission to revisit the requirements in CSR 4240-22.060 to explore evaluating risk in IRPs through the use of scenarios and sensitivities to test critical factors as an alternative to endpoint probability analysis, and to recognize the importance of well-supported, data-driven applications of any probability analyses that are used.

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."[37] 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.

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

[37] Volume 4: Supply-Side Resource Analysis, page 6.

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. 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.[38]

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.

For this IRP, Evergy evaluated a handful of different energy efficiency levels. However, we do not believe it makes sense to model levels of energy efficiency that are at a lower performance level than what the utility is achieving, i.e., the Realistic Achievable Potential minus scenario or "RAP-", reflected energy efficiency savings from a lower performance level.[39] It is our understanding from the information presented in stakeholder workshops and the IRP, along with the discovery requests that we asked, that Evergy did not evaluate the MEEIA level of savings that was developed in the MPS. Since our modeling results show some cost savings from modeling this level of energy efficiency, we believe that Evergy should have explored at least this level of energy efficiency in its IRP and should do so for future IRPs.

[38] 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

[39] Evergy 2019 DSM Potential Study. Page 1.

We would also like reiterate the comments that NEE and EFG filed on Evergy's Kansas stakeholder workshop held on January 22, 2021[40], 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 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.*[41]

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

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

[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

The Chapter 22 requirement for extreme weather is as follows:

> *(8)(B) The utility shall estimate the sensitivity of system peak load forecasts to extreme weather conditions. This information shall be considered by utility decision-makers to assess the ability of alternative resource plans to serve load under extreme weather conditions when selecting the preferred resource plan pursuant to 4 CSR 240-22.070(1).*

A responsive 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.

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 Evergy's Preferred Plans;
2. Produces much greater CO_2 emission reductions;
3. Offers the possibility of hundred of millions of dollars in savings from securitization; and
4. 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.